CenterPoint Energy

Pipeline Services
525 Milam Street
Shreveport, LA 71101

October 5, 2007

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

Re: CenterPoint Energy Gas Transmission Company, CPF 4-2007-1005M, Final Integrity Management Program Plans and Procedures

Dear Mr. Seeley:

On April 3, 2007, CenterPoint Energy Gas Transmission Company (CEGT) received a Notice of Amendment (NOA) dated March 29, 2007, issued by the Southwest Region of the Department of Transportation's Office of Pipeline and Hazardous Materials Safety Administration (PHMSA). In the NOA, PHMSA stated that, based on PHMSA's review of CEGT's Integrity Management Program (IMP) conducted in Shreveport, Louisiana, during the weeks of September 12-16 and November 14-18, 2005, PHMSA had identified apparent inadequacies within CEGT's IMP plans or procedures.

On June 29, 2007, after receiving an extension of time from PHMSA, CEGT submitted amended IMP procedures to comply with the NOA. Those IMP procedures have now been approved through CEGT's Management of Change (MOC) process. Accordingly, CEGT hereby submits its final IMP procedures to comply with the NOA.

During CEGT's MOC process, additional changes were made to seven of the documents that CEGT sent to PHMSA on June 29, 2007:

PS-03-01-200 "HCA Segment Identification"
PS-03-01-214 "Data Management"
PS-03-01-232 "External Corrosion Direct Assessment"
PS-03-01-132 "Dry Gas Internal Corrosion Direct Assessment"
PS-03-01-135 "Pressure Testing for Assessment"

PS-03-01-145 "Remediation"
O&M Book 1 Procedure 219 "Population Density and HCA Field Survey"

The changes to these seven documents did not impact the substance of the NOA response. The remaining thirty documents included with this letter are the same as those submitted on June 29, 2007, except the "draft" annotation has been removed and the effective dates, revision dates, and revision numbers have been updated."

Please contact me if you have any questions about this submission.

Sincerely,

Scott Mundy

Scott A. Mundy
Director, Pipeline Integrity
CenterPoint Energy Gas
Transmission Company

cc: Walter L. Ferguson
Debbie Ristig
Johnny Cavitt

CENTERPOINT ENERGY - INTERSTATE PIPELINES

PIPELINE INTEGRITY MANAGEMENT IN HIGH CONSEQUENCE AREAS - NATURAL GAS TRANSMISSION PIPELINES

PROGRAM DESCRIPTION DOCUMENT

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CenterPoint Energy

Pipeline Group
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PIPELINE INTEGRITY MANAGEMENT POLICY:

NATURAL GAS TRANSMISSION PIPELINES

Scope

This policy applies to the CenterPoint Energy Gas Transmission, Mississippi River Transmission and Illinois Gas Transmission pipeline systems owned and operated by CenterPoint Energy, and the operating groups within the CenterPoint Energy Pipeline organization involved in the operation, maintenance, or control of the natural gas transmission pipeline systems.

Policy

CenterPoint Energy is committed to doing business with integrity, initiative, accountability and respect for our customers and the communities in which we operate. A key ingredient of this respect is our unwavering commitment to the safe operation of our natural gas pipeline systems. The Company's integrity management program is an important part of our pipeline safety focus.

Federal legislation in the form of the Pipeline Safety Improvement Act of 2002 requires natural gas transmission pipeline operators to develop and implement an integrity management program. The PHMSA Office of Pipeline Safety has published regulations in 49 CFR Part 192, Subpart O addressing integrity management. CenterPoint Energy fully supports the goals of the legislation and the regulations.

It is the policy of the CenterPoint Energy Pipeline organization to conduct its activities in such a manner to:

- Consider first the safety of the public, employees, and contractors that may be affected by the operation of the pipeline system.
- Ensure the operation integrity of its natural gas pipeline system meeting the requirements as detailed in 49 CFR Part 192 Subpart O.
- Comply with operations and maintenance requirements per Book 1, O&M Manual of Procedures
- Comply with safety requirements per Book 6, Manual of Safety Procedures.

- Comply with environmental requirements per Book 7, Environmental Manual of Procedures, and Book 7A, Manual of Environmental Procedures – Waste Management, and meet the requirements of CenterPoint Energy's Environmental Policy.

The pipeline organization will carry out this policy through action plans supported by management. We require the commitment of each employee to achieve these objectives and are committed to providing continuing education and training to achieve its goals.

At CenterPoint Energy we are proud to be one of America's major natural gas pipeline operators, and are equally proud of both our and the industry's operating safety record. Our goal is to continue that record and enhance it through our integrity management program.

Byron R. Kelley
Group President & COO
Pipelines, Pipeline Services, & Field Services

PIPELINE INTEGRITY MANAGEMENT PROGRAM

OVERVIEW

CenterPoint Energy's goal is the delivery of product to customers without adverse effects on employees, customers, the public, and the environment. This goal is assured through the safe and reliable continuous operation of its pipeline system. The Company has developed a natural gas transmission pipeline integrity management program (hereafter called the "Integrity Management Program" or "IMP") that meets the requirements of 49 CFR 192 Subpart O – Pipeline Integrity Management, in order to maintain safe and reliable pipeline operation. The requirements implement the "Pipeline Safety Improvement Act of 2002," which became law on December 17, 2002. 49 CFR 192 Subpart O (the "rule") was published in the Federal Register on December 15, 2003 with an effective date of January 14, 2004. The rule uses the date of the law enactment (December 17, 2002) as the basis for many of the completion dates specified in the rule.

Specific processes and procedures are in place to implement the Integrity Management Program. This document describes the processes that are the keys to managing the overall program and identifies the associated procedures that implement each of the program's requirements.

COMPLIANCE SCHEDULE

The following shows when the Integrity Management Program will meet key milestones established in 49 CFR 192:

- **December 17, 2004** - Identify High Consequence Areas (HCAs), Develop a Baseline Assessment Plan, Develop a framework for a written integrity management program.

- **December 17, 2007** - Complete 50% of Baseline Assessment.

- **December 17, 2012** - Complete 100% of Baseline Assessment.

1.0 PURPOSE AND OBJECTIVES

This Integrity Management Program is a comprehensive, prescriptive-based systematic approach to maintain and improve the safety of the Company's pipeline system. The program contains policies, processes, and procedures that will help Company employees achieve successful results. The program contains five plans that provide the foundation for the program.

The five plans are as follows:

- Integrity Management Plan (Section 6.0 of this document)
- Performance Plan (Section 7.0)
- Communications Plan (Section 8.0)
- Management of Change Plan (Section 9.0)
- Quality Control Plan (Section 10.0)

Two other key elements of the program are Documentation (Section 4.0) and Personnel Qualification (Section 5.0). These key elements, together with the five plans, cover the 16 elements of an integrity management program described in Subpart O, §192.911. Each of the plans will be updated with changes and/or improvements to the knowledge base, technology, system components, environment, etc., affecting integrity management of CenterPoint Energy's pipeline system.

The foundation for the Company's program was established using the Department of Transportation's (DOT) Title 49, Part 192, Subpart O (the "rule") and ASME B31.8S-2001.

a. The Integrity Management Program includes a framework of processes and procedures that describes the implementation of each program element, describes how relevant decisions will be made and by whom, and describes how experience will be continuously incorporated into the program.

b. The Integrity Management Program upholds CenterPoint Energy's high regard for strict compliance with all safety and environmental laws and regulations. The program requires that actions be performed in a manner that minimizes environmental and safety risks.

2.0 BACKGROUND

Pipeline safety has always been a primary focus for pipeline operators. A formalized approach to gas pipeline integrity programs was initiated with the American Society of Mechanical Engineers (ASME) B31.8S "Managing System Integrity of Gas Pipelines" in 2001. The Department of Transportation, Office of Pipeline Safety, established a rule requiring formal gas pipeline integrity programs under 49 CFR 192, Subpart O as required by the "Pipeline Safety Improvement Act of 2002" enacted on December 17, 2002. The rule (published December 15, 2003 and effective January 14, 2004) generally follows the ASME standard.

The rule identifies 16 elements that must be present in a pipeline integrity management program. The table below lists each of the required elements, their relationship to sections in the ASME standard, and where each is addressed within the CenterPoint Energy Pipeline Integrity Management Program.

Regulation 49 CFR 192 Subpart O	ASME Standard B31.8S	CenterPoint Energy Program
a. Identification of all high consequence areas	Section 3 Consequences	6.1.1 High Consequence Area Identification
b. Baseline assessment plan		6.2.2 Develop Long-term Assessment Plan
c. Identification of threats to each covered pipeline segment (including data integration and a risk assessment)	Section 4 Gathering, Reviewing & Integrating Data Section 5 Risk Assessment	6.1.2 Potential Threat Impact Identification 6.1.3 Gather/Review and Integrate Data
d. Direct assessment plan, if applicable, depending on the threat assessed	Section 6.4 Direct Assessment	6.3 Implementation of Annual Assessment Plan
e. Remediating conditions found during an integrity assessment	Section 7 Responses to Integrity Assessments & Mitigation	6.3.4 Implement Repairs and Mitigation Based on Assessment
f. Process for continual evaluation and assessment	Section 6 Integrity Assessment	6.4 Post-assessment
g. If applicable, a plan for confirmatory direct assessment (CDA)		6.3.2.4 Confirmatory Direct Assessment
h. Provisions for adding preventive and mitigative measures to protect HCA	Section 7.6 Prevention Strategy/Methods	6.3.4.5 Prevention & Mitigation Strategy/Methods
i. Performance plan that includes performance measures	Section 9 Performance Plan	7.0 Performance Plan
j. Record keeping provisions	Section 4 Gathering, Reviewing & Integrating Data	4.0 Documentation

Regulation 49 CFR 192 Subpart O	ASME Standard B31.8S	CenterPoint Energy Program
k. Management of change process	Section 11 Management of Change	9.0 Management of Change Plan
l. Quality assurance process	Section 12 Quality Control Plan	10.0 Quality Control Plan
m. Communications plan that includes procedures for addressing safety concerns	Section 10 Communications Plan	8.0 Communications Plan
n. Process for providing copy of risk analysis or integrity management program to OPS and state or local authority	Section 10 Communications Plan	8.0 Communications Plan
o. Procedures for ensuring that each integrity assessment is conducted in a manner that minimizes environmental and safety risks	Section 1.2 Purpose and Objectives	1.0 Purpose and Objectives 6.3 Implementation of Annual Assessment Plan
p. Process for identification and assessment of newly-identified HCAs		6.1.1 High Consequence Area Identification Appendix A Identification of High Consequence Areas (HCAs) Process

The following table shows this program's compliance with CFR 192 Subpart O.

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.901 What do the regulations in this subpart cover?	Not required in the Pipeline Integrity Management Program	
192.903 What definitions apply to this subpart?	List of definitions in Section 11 of Pipeline Integrity Management Program	
192.905 How does an operator identify a high consequence area?	6.1.1 High Consequence Area (HCA) Identification	PS-03-04-100: " Population Density & HCA Field Survey" PS-03-01-105: "HCA Class Review" PS-03-01-200: "HCA Segment Identification" PS-03-01-210: "HCA Segment Mapping Requirements"
192.907 What must an operator do to implement this subpart?	Overview	PS-03-01-220: "Baseline Assessment Plan"

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.909 How can an operator change its integrity management program?	9.0 Management of Change Plan	PS-03-01-264: "IMP Communication Plan"
192.911 What are the elements of an integrity management program	6.1.1 High Consequence Area (HCA) Identification 6.2.2.1 Develop Long-term Assessment Plan 6.2 Risk Assessment and Inspection Schedule 6.2.4 Actions to Address Particular Threats 6.3.1.3 Direct Assessment 6.3.4 Implement Repairs and Mitigation Based on Assessment 6.4.2 Integrate Findings/Analysis into Risk Assessment and Threat Analysis 6.4.4 Update Integrity Management Plan for Specific Segments 6.3.2.4 Confirmatory Direct Assessment 6.3.4.5 Prevention and Mitigation Strategy/Methods 4.0 Documentation 7.0 Performance Plan 8.0 Communications Plan 9.0 Management of Change 10.0 Quality Control Plan	PS-03-01-200: "HCA Segment Identification" PS-03-01-220: "Baseline Assessment Plan" PS-03-01-120: "Develop Long-term Assessment Plan" PS-03-01-216: "Threat Identification and Risk Assessment" PS-03-01-230: "Direct Assessment Plan" PS-03-01-232: "External Corrosion Direct Assessment" PS-03-01-238: "Dry Gas Internal Corrosion Direct Assessment" PS-03-01-240: " SCC Direct Assessment" PS-03-01-258: "Preventive and Mitigative Measures" PS-03-01-140: "Perform DA Inspection and Repair" - Step 13 & 14 PS-03-01-260: "Continual Process For Evaluation and Assessment" PS-03-01-262: "Methods to Measure Program Performance" PS-03-01-150: "Post Assessment" PS-03-01-214: " Data Management" PS-03-01-266: "IMP Management of Change" (Specific to IMP) PS-03-01-268: "IMP Quality Assurance" (Specific to IMP) PS-03-01-264: "IMP Communication Plan" O&M Books 6, 7, 7a on safety and environment

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.913 When may an operator deviate from certain requirements of this subpart in its program?	Not applicable	
192.915 What knowledge and training must personnel have to carry out an integrity management program?	5.0 Personnel Qualifications 5.1 Supervisory Personnel 5.2 Technical Personnel	PS-03-01-272 "IMP Personnel Qualification Requirements"
192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?	6.1 Pipeline System Data Integration 6.1.2 Potential Threat Impact Identification 6.1.3 Gather, Review, and Integrate Data 6.2 Risk Assessment and Inspection Schedule 6.2.1 Risk Assessment 6.2.2 Develop Long-term Assessment Plan 6.2.4 Actions to Address Particular Threats	PS-03-01-216: "Threat Identification and Risk Assessment" PS-03-01-110: "Gather, Review, and Integrate Data" PS-03-01-115: "Risk Assessment" PS-03-01-260: "Continual Process For Evaluation and Assessment" PS-03-01-258: "Preventive and Mitigative Measures"
192.919 What must be in the baseline assessment plan?	6.1.2 Potential Threat Impact Identification 6.2.2 Develop Long-term Assessment Schedule 6.2.4 Actions to Address Particular Threats 6.3.1.3 Direct Assessment	PS-03-01-115: "Risk Assessment" PS-03-01-224: "Assessment Methods Selection Process" PS-03-01-230: "Direct Assessment Plan" PS-03-01-232: "External Corrosion Direct Assessment" PS-03-01-238: "Dry Gas Internal Corrosion Direct Assessment"

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.921 How is the baseline assessment to be conducted?	6.3.1.1 Pipeline In-line Inspections 6.3.1.2 Pressure Testing 6.3.1.3 Direct Assessment 6.3.1.4 Other Integrity Assessment Methodologies 6.2.2 Develop Long-term Assessment Plan 6.3.1 Perform Planned Assessment	PS-03-01-120: "Develop Long-term Assessment Plan" PS-03-01-115: "Risk Assessment" PS-03-01-224: "Assessment Methods Selection Process" PSS-03-01-200: "HCA Segment Identification"
192.923 How is DA used and for what threats?	6.3.1.3 Direct Assessment	PS-03-01-230: "DA Plan" PS-03-01-232: "External Corrosion Direct Assessment" PS-03-01-224: "Assessment Methods Selection Process" PS-03-01-140: "Perform DA Inspection & Repair"
192.925 What are the requirements of external corrosion direct assessment (ECDA)?	6.3.2.1 External Corrosion Direct Assessment	PS-03-01-230: "DA Plan" PS-03-01-232: "External Corrosion Direct Assessment" PS-03-01-240: "SSC Direct Assessment"
192.927 What are the requirements for using internal corrosion direct assessment (ICDA)?	6.3.2.2 Internal Corrosion Direct Assessment	PS-03-01-230: "DA Plan" PS-03-01-238: " Dry Gas Internal Corrosion Direct Assessment"
192.929 What are the requirements for using direct assessment for stress corrosion cracking (SCCDA)?	6.3.2.3 Stress Corrosion Cracking Direct Assessment	PS-03-01-230: "DA Plan" PS-03-01-240: "SCC Direct Assessment"
192.931 How may confirmatory direct assessment (CDA) be used?	6.3.2.4 Confirmatory Direct Assessment	PS-03-01-230: "DA Plan" PS-03-01-260: "Continual Process for Evaluation and Improvement"

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.933 What actions must be taken to address integrity issues?	6.4 Post-assessment 6.4.3 Determine Reassessment Schedule for Each Segment	PS-03-01-140: "Perform DA Inspection & Repair" PS-03-01-135: "Perform Planned Assessment-Pressure Test" PS-03-01-130: "Perform Planned Assessments – In-Line Inspection (ILI)" PS-03-01-250: "Pipeline Evaluation and Remediation"
192.935 What additional preventative and mitigative measures must an operator take to protect the high consequence area?	6.2 Risk Assessment and Inspection Schedule 6.2.4 Action to Address Particular Threats	PS-03-01-258: "Preventive and Mitigative Measures" PS-03-01-254: " Threat Prevention & Repair Chart"
192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?	6.0 Integrity Management Plan	PS-03-01-260: "Continual Process For Evaluation and Improvement" PS-03-01-150: "Post Assessment" process for overall pipeline (in general)
192.939 What are the required reassessment intervals?	6.4.3 Determine Reassessment Schedule for Each Segment	PS-03-01-260: "Continual Process For Evaluation and Improvement"
192.941 What is a low stress reassessment?	6.3.3 Low Stress Reassessment	PS-03-01-260: "Continual Process For Evaluation and Improvement"
192.943 When can an operator deviate from these reassessment intervals?	Not applicable	PS-03-01-260: "Continual Process For Evaluation and Improvement"
192.945 What methods must an operator use to measure program effectiveness?	7.0 Performance Plan	PS-03-01-150: "Post Assessment" PS-03-01-262: "Methods to Measure Program Performance"
192.947 What records must be kept?	4.2 Minimum Document Requirements	PS-03-01-214: "Data Management"

Subpart	Pipeline Integrity Management Program Compliance Section	Procedure/Process Document
192.949 How does an operator notify OPS?	8.3 Office of Pipeline Safety	PS-03-01-264: "IMP Communication Plan"
192.951 Where does an operator file a report?	8.3 Office of Pipeline Safety	PS-03-01-264: "IMP Communication Plan"

3.0 MANAGEMENT ACCOUNTABILITY AND RESPONSIBILITY

The Director, Pipeline Integrity is responsible for the management and implementation of CenterPoint Energy's Integrity Management Program. General responsibilities for the various components of the program are shown below.

Title	Responsibility
Director, Pipeline Integrity	Overall management of the program.
Manager, Pipeline Integrity	Overall day-to-day implementation of the program.
Division VP - Operations	Overall management of the Operations programs and tasks required to implement the program.
Director, Project Services	Overall management of the Project Services programs and tasks required to implement the program
Senior Director, Strategy and Support Services	Overall management of the regulatory compliance, safety, environmental, mapping and database management programs and tasks required to implement the program.

Responsibilities for specific tasks, processes and activities within the CenterPoint Integrity Management Program are shown in the following table:

Overall	
• Propose annual O&M and capital budgets to executive management for approval	Director, Pipeline Integrity
• Assign appropriate personnel to manage and execute the Company's IMP	
• Establish annual goals for IMP	
• Establish and sponsor the Pipeline Integrity oversight group (PIT)	
• Develop original IMP and a process for revisions and improvements to the program	

Overall (cont'd)	
• Develop processes and procedures that support the Integrity Management Program	Manager, Pipeline Integrity
• Manage development of the baseline assessment plan and subsequent annual assessment plans	
• Supervise implementation of annual assessment plan	
• Manage overall coordination of interdepartmental activities, tasks and processes	
Identification of High Consequence Areas (HCAs)	
• Initial HCA determination	Pipeline Integrity Engineer
• Ongoing HCA determination	
Gather, Review and Integrate Data	
• Collect data about pipe characteristics, operating and repair history	Pipeline Integrity Engineer, Data Management Specialist
• Input data into Asset Inventory Database	
• Integrate data	
Threat Analysis and Risk Assessment	
• Perform threat analysis	Pipeline Integrity Engineer
• Determine appropriate mitigative measures and validate assessment method	
• Perform risk assessment annually	
• Review risk assessment methods and processes annually to ensure they are yielding relevant, accurate results consistent with the objectives of the overall IMP	Director, Pipeline Integrity

Develop Baseline Assessment Plan & Perform Planned Assessments	
• Develop baseline assessment plan	Manager, Pipeline Integrity
• Determine appropriate assessment methods	Pipeline Integrity Engineer
• Perform assessments – Direct Assessments (DA) – In-Line Inspections (ILI) – Pressure Tests (PT)	Direct Assessment Manager (DA) Pipeline Integrity Engineer (ILI) Project Services (ILI and PT) Operations (ILI)
Implement Preventive and Mitigative Measures, Remediations, Repairs	
• Take appropriate remedial measures based on assessment findings	Project Services
• Document assessments and remedial measures	Direct Assessment Manager, Pipeline Integrity Engineer
• Verify all evaluations of defects are performed by qualified personnel	
• Determine appropriate method for pipeline repairs	Pipeline Integrity Engineer
Integrate Findings into Threat Analysis and Risk Assessment	
• Evaluate assessment findings and determine conclusions	Direct Assessment Manager (DA) Pipeline Integrity Engineer (ILI, PT)
• Determine reassessment schedule	
• Integrate findings and conclusions into IMP	Pipeline Integrity Engineer
Data Management	
• Determine which data is needed for managing, executing, and documenting the IMP	Director, Pipeline Integrity
• Establish pipeline integrity related documentation processes and ensure data, records, and reports are maintained according to the processes	Manager, Pipeline Integrity
• Develop automated data management system for Pipeline Integrity use	Data Management Specialist
• Maintain records of assessments and evaluations of pipeline segments	
• Maintain records of the original baseline assessment plan and subsequent long-term and annual assessment plans	

Performance Plan	
• Establish a performance matrix; develop and revise performance measures	Director, Pipeline Integrity
• Submit OPS-required performance measures semi-annually (4 overall measures) to Manager, Compliance	Pipeline Integrity Engineer
• Integrity Management Oversight Group meets quarterly to review IMP performance	Manager, Pipeline Integrity
• Prepare an annual IMP performance report	Pipeline Integrity Engineer
Communications	
• Semi-annual reporting of performance measures	DOT Compliance Manager
• Develop written responses to inquiries and other correspondence from regulatory agencies	
• Access the Office of Pipeline Safety (OPS) website annually to obtain updated integrity management audit protocols	Pipeline Integrity Engineer
Management of Change	
• Develop change management program for IMP that is integrated with Company change management program	Director, Pipeline Integrity
• Originate proposed change request	Any employee
• Review change request	Change Review Committee
• Approve changes to IMP	Director, Pipeline Integrity
• Approve changes to data, inputs to risk assessment	Pipeline Integrity Engineer
• Store change request documents and update change log	Data Management Specialist
Quality Assurance	
• Conduct audit	Manager, Compliance
• Prepare audit report	
• Follow up on action items identified in audit report	Director, Pipeline Integrity

Operations & Maintenance	
• Develop and maintain O&M procedures and ensure procedures complement and/or enhance the IMP. Examples of these procedures include: line locating, line marking, One-Call program, population density surveys, etc.	Division VP - Operations
Engineering and Technical	
• Develop and maintain construction, engineering, and technical processes and procedures, and ensure they complement and/or enhance the IMP (see below):	See below:
– Engineering Standards	Director, Project Services
– Construction Specifications	Director, Project Services
– Corrosion Control	Corrosion Program Manager
– Pipe defect evaluation, pipe repair, integrity analysis	Director, Pipeline Integrity

The following table is an additional reference that also shows responsibility assignments. The responsibilities in this table are identified for the 16 elements described in the rule for an integrity management program.

49 CFR 192 Subpart O §192.911 16 elements	Responsible Person
a) Identification of all high consequence areas	Pipeline Integrity Engineer
b) Baseline Assessment Plan	Manager, Pipeline Integrity
c) Identification of threats to each covered pipeline segment (including data integration and a risk assessment)	Pipeline Integrity Engineer
d) Direct assessment plan, if applicable, depending on the threat assessed	Direct Assessment Manager
e) Remediating conditions found during an integrity assessment	Manager, Pipeline Integrity

49 CFR 192 Subpart O §192.911 16 elements	Responsible Person
f) Process for continual evaluation and assessment	a) Pipeline Integrity Engineer, and b) Direct Assessment Project Manager
g) If applicable, a plan for confirmatory direct assessment (CDA)	Manager, Direct Assessment
h) Provisions for adding preventive and mitigative measures to protect HCAs	Manager, Pipeline Integrity
i) Performance plan that includes performance measures	Director, Pipeline Integrity
j) Record keeping provisions	Manager, Pipeline Integrity
k) Management of change process	Director, Pipeline Integrity
l) Quality assurance process	Director, Pipeline Integrity
m) Communications plan that includes procedures for addressing safety concerns	Director, Pipeline Integrity
n) Process for providing copy of risk analysis or integrity management program to OPS and state or local authority	DOT Compliance Manager
o) Procedures for ensuring that each integrity assessment is conducted in a manner that minimizes environmental and safety risks	Senior Director, Strategy and Support Services
p) Process for identification and assessment of newly-identified HCAs	Pipeline Integrity Engineer

4.0 DOCUMENTATION

Proper documentation of each aspect of the CenterPoint Integrity Management Program is necessary for the successful implementation, review and improvement of integrity management activities. There are a variety of documents and data generated in support of the program.

4.1 GENERAL CATEGORIES OF INFORMATION

1. PROGRAM, PLAN, PROCESS AND PROCEDURE INFORMATION

   The Program Description Document for the Company's Integrity Management Program that includes summary descriptions of select processes and references other processes and supporting procedures, including forms, utilized to implement the program.

2. INFORMATION GENERATED THROUGH IMPLEMENTATION OF THE INTEGRITY MANAGEMENT PROGRAM:

   Information required to plan and schedule integrity assessments in high consequence areas, such as:

   - Identified HCA segments
   - Risk assessments and input data
   - Risk assessment results
   - Assessment Schedules (Baseline, Long-Term, Annual Updates)

   Information required for conducting integrity assessments, such as the data gathered and integrated in the pre-assessment steps:

   - Pipe physical characteristics (attribute) data
   - Construction data
   - Operational data
   - Inspection data (historical inspections)

Information obtained from the assessments, such as:

- In-line inspection reports
- Pressure test results
- Indirect inspection data from direct assessments
- Direct examination data from direct assessments

Information on pipeline repairs and other remediation activities:

- Dig site as-found information
- Reports on coating repairs, pipe replacements, pipe repairs, and other remediation actions

Post assessment reports:

- Conclusions and recommendations
- Reassessment intervals

3. INFORMATION GENERATED OUTSIDE THE INTEGRITY MANAGEMENT PROGRAM THAT AFFECTS THE PROGRAM:

- Facility replacements and additions
- Operations and maintenance activities

4. CHANGE MANAGEMENT HISTORY

4.2 DATA MANAGEMENT

An integrated database of information has been established to support the management and operation of CenterPoint Energy's pipelines. The database has also been designated as the repository for information related to pipeline integrity. The Data Management Specialist is responsible for gathering, reviewing, and integrating segment-specific data from all sources to support pipeline integrity management.

The database is being maintained with information as required in the Integrity Management Program by pipeline segment. As the pipeline inspections are completed, additional data will be added to the database. Additional data acquired for operations and maintenance activities will also be added.

The Data Management Specialist ensures that all data necessary for the monitoring, management, and implementation of the Company's Integrity Management Program is retained for the life of the pipeline.

Procedure PS-03-01-214: "Data Management", describes the process for management and retention of data and information required to support and substantiate the Integrity Management Program.

4.3 DATABASE

Within the context of the CenterPoint Integrity Management Program, "Asset Inventory Database" is comprised of three components of the Company's database structure.

PODS (Pipeline Open Data Structure) is a commercial software package that provides a consistent structure for storage and maintenance of certain data that pertains to pipe, pipeline components, and pipeline facilities. For example, pipe diameter, wall thickness, MAOP, pressure test data, valve type, year installed, are typical of the types of data maintained in PODS.

The Maintenance Management System (MMS) is also a commercial software package. MMS is used to maintain information about equipment performance, repair history, and maintenance requirements and is also used to generate preventive maintenance schedules.

The third component is a document database that is used to maintain MS Word documents such as memos, notes, analyses, justifications, and electronic forms; MS Excel spreadsheets; other work product files produced with commercial PC-based computer software; and also scanned images of items such as handwritten notes, manually filled in forms, and marked up drawings.

4.4 MINIMUM DOCUMENT REQUIREMENTS

The Company's Integrity Management Program will meet or exceed the following records requirements:

- Integrity Management Program
- Documents supporting threat identification and risk assessment
- Baseline assessment plan
- Documents that support decisions, analyses and processes developed and used to implement and evaluate each element of the Baseline Assessment Plan and Integrity Management Program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any of the program elements.
- Personnel training and qualification records, including a written description of the training program
- Long-term Assessment Plan and all supporting documentation that prioritizes the conditions found during and assessment for evaluation and remediation, including technical justifications for the schedule.
- Documents that describe and implement the Direct Assessment Plan, including documentation of analyses, decisions and results.
- Documents that describe and implement Confirmatory Direct Assessments, including documentation of analyses, decisions and results.
- Documents and notifications to the Office of Pipeline Safety and, when applicable, State pipeline safety authorities with which OPS has an interstate agent agreement, and State or local pipeline safety authorities that regulate a covered pipeline segment within that State.

Documentation requirements are identified in the various procedures that implement the Integrity Management Program.

4.5 RESPONSIBILITIES

Director, Pipeline Integrity

- Determine which data is needed for managing, executing and documenting the Integrity Management Program

Manager, Pipeline Integrity

- Establish pipeline integrity related documentation processes and ensure data, records and reports are maintained according to the processes

Data Management Specialist

- Oversees data retention needed for Integrity Management Program
- Maintains file in Asset Inventory Database

Data Integrity

- Maintains PODS data
- Maintains MMS data
- Maintains Company intranet documents (for example, procedures and maps)

5.0 PERSONNEL QUALIFICATION

CenterPoint Energy's policy is to assure that all employees are competent to handle the specific areas for which they are responsible. Procedure PS-03-01-272: "IMP Personnel Qualification Requirements", describes the qualification criteria and requirements for personnel involved with the Company's Integrity Management Program.

Management and supervisory personnel whose responsibilities relate to the Company's Integrity Management Program will possess and maintain a thorough knowledge of the Integrity Management Program and of the Program's elements for which the supervisor is responsible. Company personnel who qualify as a supervisor for the Integrity Management Program will have appropriate training or experience in the area for which the person is responsible.

The program includes specific criteria for qualification of Company personnel who carry out assessments and evaluate assessment results, including review and analysis of assessment results and decisions on actions to be taken based on the assessments.

Specific qualification criteria are also included for persons responsible for implementation of preventive and mitigative measures, including marking and locating of buried structures, or who directly supervise excavation work carried out in conjunction with an integrity assessment. Personnel involved in preventive and mitigative activities will meet the qualification requirements described in the Company's Operator Qualification program.

6.0 INTEGRITY MANAGEMENT PLAN

CenterPoint Energy's Integrity Management Program incorporates several key elements including an understanding of the integrity risks, a thorough assessment of each risk, a mitigation/remediation process to address each risk, and a continuous integrity assessment process.

Pipeline System Data Integration

Identifying and locating High Consequence Areas (HCAs) and the potential threats to specific pipeline segments will indicate the data elements required for integrity management. Initial data is collected from attribute and construction data. Additional data is integrated as it becomes available through O&M activities and pipeline integrity inspections. Finally, the information is distributed through reports and alignment sheets that provide the information for a specific pipeline segment. Any new or replacement pipe to the pipeline system is incorporated into the database and an initial assessment is completed within 10 years of installation.

Risk Assessment & Inspection Schedule

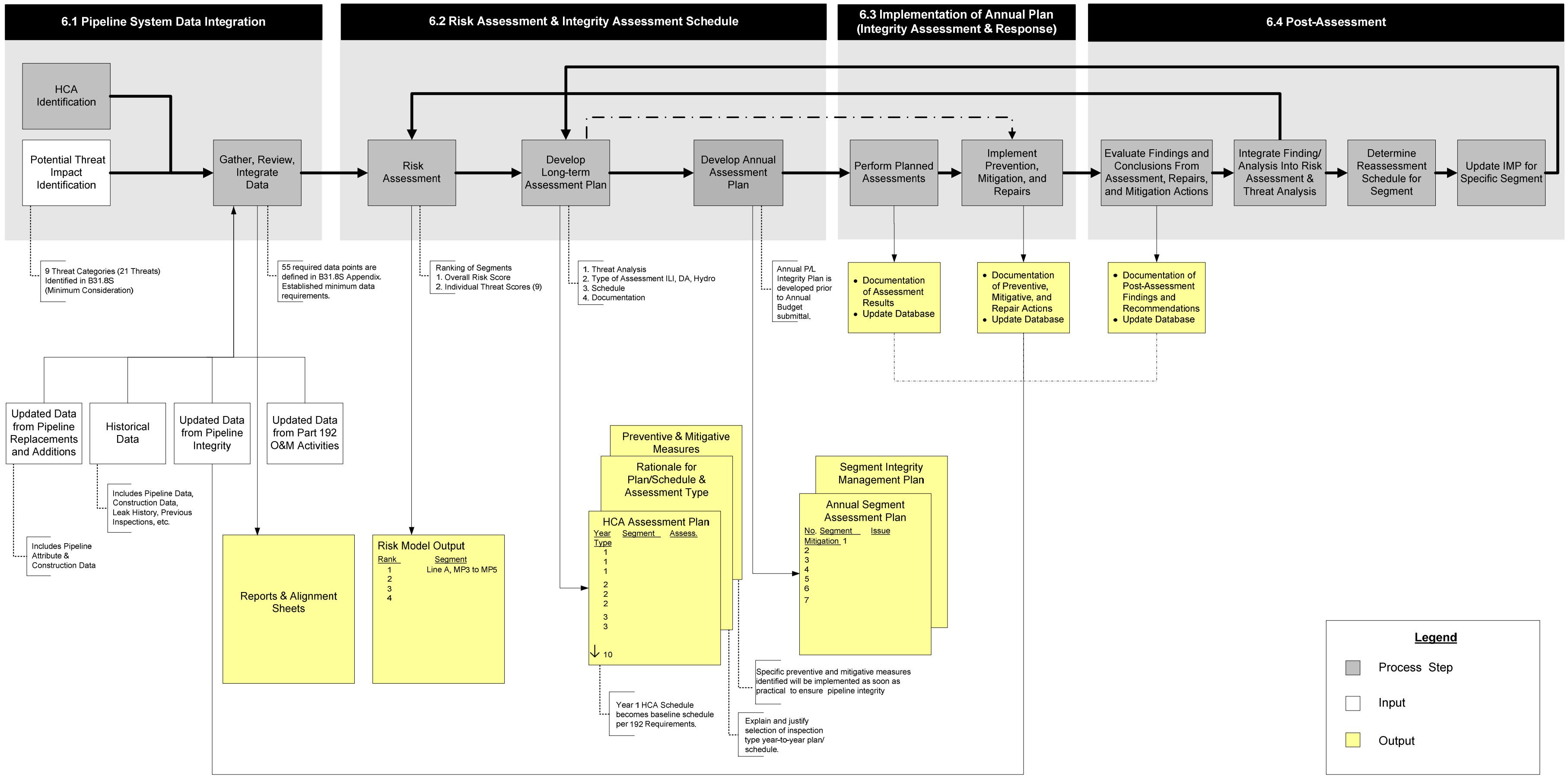
The Company's relative risk model ranks each pipeline segment from highest to lowest risk. The results of the risk assessment are used to develop a long-term (10-year) assessment plan and schedule. The initial long-term plan becomes the baseline assessment schedule. Before each subsequent year begins, the long-term plan is used to develop an annual assessment plan that provides additional details about the assessments for the coming year.

Implementation of Annual Assessment Plan

The annual assessment plan details integrity management activities for the year. Assessment results are documented and used to formulate immediate and scheduled repair and mitigation actions, as appropriate. The actions taken are documented. This process ensures the availability of the information gained during inspection and repairs for both data integration and management of the segment integrity management plan.

Post-assessment

After completing the assessment and repair/mitigation for each segment, the findings, conclusions, recommendations, and actions are used to update the segment Pipeline Integrity Management Plan and schedule reassessment activity, as appropriate. In addition, any recommended changes to risk assessment and threat analysis are forwarded to the pipeline integrity management group and incorporated as necessary into the long-term and/or annual assessment plans.


6.1 Pipeline System Data Integration
6.2 Risk Assessment & Integrity Assessment Schedule
6.3 Implementation of Annual Plan (Integrity Assessment & Response)
6.4 Post-Assessment
HCA Identification
Potential Threat Impact Identification
Gather, Review, Integrate Data
Risk Assessment
Develop Long-term Assessment Plan
Develop Annual Assessment Plan
Perform Planned Assessments
Implement Prevention, Mitigation, and Repairs
Evaluate Findings and Conclusions From Assessment, Repairs, and Mitigation Actions
Integrate Finding/ Analysis Into Risk Assessment & Threat Analysis
Determine Reassessment Schedule for Segment
Update IMP for Specific Segment
9 Threat Categories (21 Threats) Identified in B31.8S (Minimum Consideration)
55 required data points are defined in B31.8S Appendix. Established minimum data requirements.
Ranking of Segments
1. Overall Risk Score
2. Individual Threat Scores (9)
1. Threat Analysis
2. Type of Assessment ILI, DA, Hydro
3. Schedule
4. Documentation
Annual P/L Integrity Plan is developed prior to Annual Budget submittal.
Documentation of Assessment Results
Update Database
Documentation of Preventive, Mitigative, and Repair Actions
Update Database
Documentation of Post-Assessment Findings and Recommendations
Update Database
Updated Data from Pipeline Replacements and Additions
Historical Data
Updated Data from Pipeline Integrity
Updated Data from Part 192 O&M Activities
Includes Pipeline Data, Construction Data, Leak History, Previous Inspections, etc.
Includes Pipeline Attribute & Construction Data
Reports & Alignment Sheets
Risk Model Output
Rank Segment
1 Line A, MP3 to MP5
2
3
4
Preventive & Mitigative Measures
Rationale for Plan/Schedule & Assessment Type
HCA Assessment Plan
Year Type Segment Assess.
1
1
1
2
2
2
3
3
10
Segment Integrity Management Plan
Annual Segment Assessment Plan
No. Segment Mitigation Issue
1
2
3
4
5
6
7
Specific preventive and mitigative measures identified will be implemented as soon as practical to ensure pipeline integrity
Year 1 HCA Schedule becomes baseline schedule per 192 Requirements.
Explain and justify selection of inspection type year-to-year plan/ schedule.
Legend
Process Step
Input
Output

6.1 PIPELINE SYSTEM DATA INTEGRATION

The first steps of CenterPoint Energy's program consist of gathering, analyzing, and integrating the pertinent data for each pipeline segment and each perceived threat within a segment. These steps are repeated after integrity assessment and mitigation activities are implemented or as O&M practices are changed or modified.

6.1.1 High Consequence Area Identification

The first step to pipeline system integrity is to identify HCAs according to the regulations' definition provided below. CenterPoint Energy uses method 1 and method 2 for HCA identification.

The initial effort to identify HCAs is complemented by a continuous process of reassessment and identification of areas that may meet the regulatory definition. When an area is newly identified as an HCA, it is incorporated into the Integrity Management Program and baseline assessment is scheduled for that pipeline segment within 10 years from the initial identification date.

An HCA is an area near the transmission pipeline segment determined by the Pipeline Operator through either Method 1 or 2 below:

1. An area defined as:

    a) a Class Location 3 as defined in 192.5; or

    b) a Class Location 4 as defined in 192.5; or

    c) any area outside a Class 3 or Class 4 location where the potential impact radius (PIR) is greater than 660 feet (200 meters), and the area within a potential impact circle (PIC) contains 20 or more buildings intended for human occupancy; or

    d) the area within a PIC containing an identified site.

2. The area within a PIC containing

    a) 20 or more buildings intended for human occupancy, unless the exception identified below applies; or,

    b) an identified site.

Where a PIC is calculated under either Method 1 or 2, defined above, to establish an HCA, the HCA extends axially along the length of the pipeline from the outermost edge of the first PIC that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous PIC that contains either an identified site or 20 or more buildings intended for human occupancy.

Exception (see 2.a) above) - If in identifying an HCA under paragraph 1.c) or 2.a), the radius of the PIC is greater than 660 feet (200 meters), the Company may identify an HCA based on a prorated number of buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If the Company uses this approach, the Company must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the PIC (that is, the prorated number of buildings intended for human occupancy is equal to [20 x (660 feet (or 200 meters)/PIR in feet (or meters))^2]).

An identified site means:

A) An outside area or open structure that is occupied by 20 or more persons on at least 50 days in any twelve-month period (the days need not be consecutive). (Examples include, but are not limited to: beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or

B) A building that is occupied by twenty 20 or more persons on at least five days a week for ten weeks in any twelve-month period (the days and weeks need not be consecutive). (Examples include, but are not limited to: religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks); or

C) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include, but are not limited to: hospitals, prisons, schools, daycare facilities, retirement facilities, or assisted-living facilities.

PIC means a circle with a radius equivalent to the PIR.

PIR means the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property. PIR is determined by the formula

$r = 0.69 * \sqrt{(p \times d^2)}$

Where:

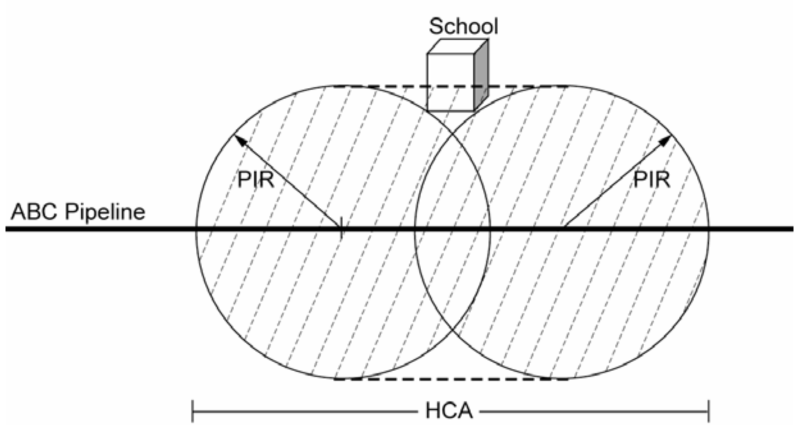
d = the nominal diameter of the pipeline in inches

p = the pipeline segment's maximum allowable operating pressure (MAOP) in psi

r = the radius of a circular area surrounding the failure in feet

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending on their heat of combustion. If the gas being transported is other than natural gas, Section 3.2 of ASME B31.8S must be used to calculate the impact radius formula.

Determining High Consequence Area



Refer to Procedure PS-03-01-200: 'HCA Segment Identification" for detailed procedural information**.**

6.1.2 Potential Threat Impact Identification

The next step is to identify the potential threats to the integrity of the pipeline. The Pipeline Research Committee International has classified gas pipeline incident data into 21 root causes. The 21 root causes are divided into nine categories. The nine categories are further classified into three failure mode groups. The groups and their respective 21 root causes are listed on the following page. Although ASME B31.8S does not consider cyclic fatigue to be a significant concern for gas transmission pipelines, the rule requires that the effects of cyclic fatigue be considered during the evaluation of any covered pipeline segment.

Time-Dependent

- External Corrosion
- Internal Corrosion
- Stress Corrosion Cracking

Stable

- Manufacturing-Related Defects
  - Defective pipe seam
  - Defective pipe
- Welding/Fabrication Related
  - Defective pipe girth weld
  - Defective fabrication weld
  - Wrinkle bend or buckle
  - Stripped threads/broken pipe/coupling failure
- Equipment
  - Gasket O-ring failure
  - Control/relief equipment malfunction
  - Seal/pump packing failure
  - Miscellaneous

Time-Independent

- Third-Party/Mechanical Damage
  - Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
  - Previously damaged pipe (delayed failure mode)
  - Vandalism

- Incorrect Operations
  - Incorrect operational procedure
- Weather-Related and Outside Forces
  - Cold weather
  - Lightning
  - Heavy rains or floods
  - Earth movements

Each segment of the pipeline system will undergo an analysis to identify each type of potential threat to its integrity. The analysis will identify the potential for simultaneous threats to the pipeline (interactive effect).

6.1.3 Gather, Review, and Integrate Data

Comprehensive pipeline and facility knowledge is essential. Integrating the data elements is necessary to obtain complete and accurate information needed for the Integrity Management Program.

6.1.3.1 Data Requirements

The desired data may be summarized into four categories: attribute, construction, operational, and inspection data. Attribute data refers to specific data about each segment of the pipeline system. The data collected for each pipeline segment will include the information below:

Attribute

- Diameter
- Pipe-wall thickness
- Pipe Grade
- Seam type and joint factor
- Manufacturer
- Manufacturer date

- Material properties
- Equipment

Construction

- Year of installation
- Bending method
- Joining method, process, and inspection results
- Depth of cover
- Crossings/casings
- Pressure test
- Field coating methods
- Soil, backfill
- Inspection reports
- Cathodic protection installed
- Coating type

Operational

- Gas quality
- Flow rate
- Normal maximum and minimum operating pressures
- Leak/failure history
- Coating condition
- Cathodic protection system performance
- Pipe-wall temperature
- Pipe inspection reports

- External and internal corrosion monitoring
- Pressure fluctuations
- Regulator/relief performance
- Encroachments
- Repairs
- Vandalism
- External forces

Inspection Data

- Pressure tests
- In-line inspections
- Bell-hole inspections
- Cathodic protection inspections (Close Interval Survey)
- Coating condition inspections (Direct Current Voltage Gradient)
- Audits and reviews

These data elements are then summarized by applicability to specific threats and used as input for the risk assessment process.

6.1.3.2 Data Gathering

The required data elements may be found in design and construction files as well as current operational and maintenance records. Typical data sources include the following:

- Piping and instrumentation drawings (P&ID)
- Pipeline alignment sheets
- Original construction inspector notes/records
- Pipeline aerial photography
- Facility drawings/maps
- As-built drawings
- Material certifications
- Survey reports/drawings
- Safety-related condition reports
- Operator standards/specifications
- Industry standards/specifications
- Inspection records
- Test reports/records
- Incident reports
- Compliance records
- Design/engineering reports
- Technical evaluations
- Manufacturer equipment data

When data is missing or questionable, conservative assumptions will be used or, alternatively, higher risk values will be assigned. Assumptions will be comprehensively documented.

6.1.3.3 Data Integration

Individual data elements are combined and analyzed to realize the full value of integrity and risk assessment. CenterPoint Energy's approach merges multiple data elements to improve confidence that a specific threat may or may not apply to a pipeline segment.

Data integration is included in the risk assessment and post assessment processes.

CenterPoint Energy uses its process PS-03-01-110: "Gather, Review, and Integrate Data" to manage data integration.

6.2 RISK ASSESSMENT AND INSPECTION SCHEDULE

The information gathered in the previous sections is used to determine relative risk and develop inspection schedules that are commensurate with the risk. The process consists of three steps: assess risk, develop a baseline assessment plan, and develop an annual assessment plan.

6.2.1 Risk Assessment

The Risk Assessment process is an evaluation of the collected and integrated data collected in the previous sections. The Company's risk assessment identifies conditions and/or location-specific events that are threats to the structural integrity of the pipeline. It also involves an understanding of the probability and consequence of each event. The Company defines risk as the product of probability and consequence. The risk assessment identifies the relative risk posed by each event to a given segment of CenterPoint Energy's pipeline system.

Where applicable, special consideration will be given to any plastic pipe, Pre-1970 low frequency electric resistance welded (ERW) pipe, and lap welded pipe identified in HCAs when assessing risks.

Refer to Procedure PS-03-01-216: "Threat Identification and Risk Assessment" for detailed procedural information.

6.2.1.1 Risk Assessment Objectives

Risk assessment of pipeline integrity includes the following:

- Identification of significant threats to the pipeline segment

- Prioritization for scheduling integrity assessment and mitigating action
- Assessment of benefits from mitigating action
- Determination of the most effective mitigation for each threat
- Assessment of the integrity impact from modified inspection intervals
- Assessment of the alternative inspection technologies

6.2.1.2 Risk Assessment Approach

CenterPoint Energy uses a relative assessment model to determine the relative risk for each of the affected areas. This approach was selected as the most appropriate based on an assessment of the following four risk assessment approaches:

- Use of subject matter experts to assign relative risk values
- Relative assessment models
- Scenario-based models
- Probability models

Subject matter experts may be used to validate the results of risk assessments.

6.2.1.3 Risk Analysis

The risk analysis assigns probabilities to each threat identified and the severity of consequence from each potential incident. The Company completes this for each segment of the pipeline system. The risk analysis follows procedure PS-03-01-216: “Threat Prevention and Risk Assessment”.

6.2.1.4 Risk Prioritization

Risk prioritization is a force-ranking of all the risks into a relative priority. The information generated about potential impact areas and HCAs are the keys to arriving at a prioritized list of all the threats to each segment of CenterPoint Energy’s pipeline system. This prioritized list is used to prepare an implementation schedule for completing the baseline integrity assessment for the pipeline system. Priorities are adjusted on an annual basis or as new sections of pipeline are added to the system and the risk analysis is run.

CenterPoint Energy developed a Risk Assessment process (PS-03-01-115) to standardize the management of risk assessment for the program.

6.2.1.5 Risk Analysis Validation

Risk analysis validation is an important step in the assessment process. Validation assures the results obtained are logical and consistent with industry experience.

Risk validation is performed through inspections, examinations, and evaluations of locations identified as high and low priority risk. Validation may also be achieved by considering other locations' information regarding the condition of a pipeline segment with a similar risk profile. Risk assessment will be repeated if warranted by the validation process.

6.2.2 Develop Long-term Assessment Plan

The Risk Assessment is the basis for development of a long-term assessment plan that prioritizes the most susceptible areas and a schedule for addressing the threats to each covered pipeline segment within the time allotted by the federal regulations. At the end of each annual assessment, the long-term plan is reviewed to determine if any changes are warranted due to newly acquired information that may impact the schedule or prioritization of planned assessments. The development of the plan and its annual review are identified in the Develop Long-term Assessment Plan Process (PS-03-01-120).

CenterPoint Energy has developed a process flowchart PS-03-01-224: "Assessment Methods Selection Process" to select assessment methods to address each threat to a covered pipeline segment.

6.2.2.1 Baseline Assessment Plan

The initial issue, or Revision 0, of the Long-Term Assessment Plan is the Baseline Assessment Plan which remains fixed and is maintained in the Company's database for the life of the Integrity Management Program. The Baseline Assessment Plan is known as the Long-Term Assessment Plan once updates and revisions are made. This plan is developed according to the process referenced above. The contents of the baseline assessment plan include the following components:

- Identification of the potential threats to each covered pipeline segment and the supporting documentation for threat identification;
- The assessment methods selected to address the potential threats to each covered pipeline segment and the supporting documentation for assessment method selection;
- A schedule for completing the integrity assessment for all covered pipeline segments;

6.2.3 Develop Annual Assessment Plan

The information obtained from the Risk Assessment combined with the baseline assessment plan form the basis for the annual assessment plan. The annual assessment plan is a working document used to plan, communicate and monitor integrity management activities for the year. This process is referenced in process PS-03-01-125: "Develop Annual Assessment Plan".

6.2.4 Actions to Address Particular Threats

The Integrity Management Program has been designed to identify specific threats in the following five categories:

- Third-party damage
- Cyclic failure
- Manufacturing and construction defects
- Electric resistance welded (ERW) pipe
- Corrosion

Data integration identifies all segments with similar characteristics subject to a particular threat. The threat is used to determine risk and to prioritize the integrity baseline assessment or reassessment.

The specific actions to address these threats are detailed in PS-03-01-258: “Preventive and Mitigative Measures”.

6.3 IMPLEMENTATION OF ANNUAL ASSESSMENT PLAN

Implementing the annual plan requires performing the assessments as well as the repairs or mitigation determined by the assessments. Each assessment is completed in accordance with all applicable environmental and safety laws to ensure the protection of employees, customers, the public, and the environment as outlined in the Company’s Safety and Environmental Manuals.

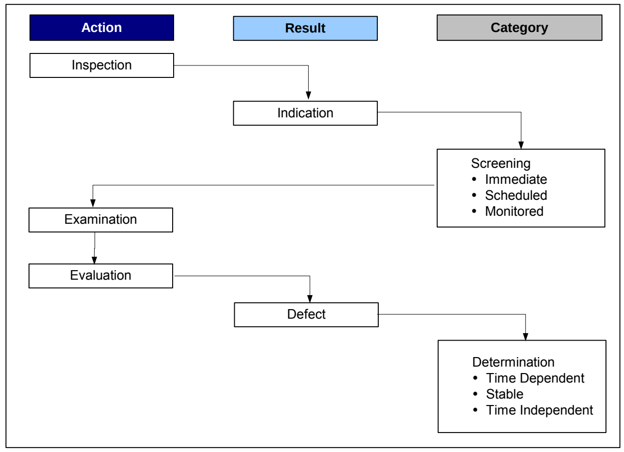
6.3.1 Perform Planned Assessments

Integrity assessment is the process of conducting inspections, examinations, or evaluations to determine the condition of a pipeline segment. There are essentially three integrity assessment methods that can be used:

- In-Line Inspection (ILI) (PS-03-01-244: “In-line Inspection and Analysis”)
- Pressure Test (Book 2, Manual of Construction Specifications, Specification 47, Pipeline Pressure Testing)
- Direct assessment (PS-03-01-232: “External Corrosion Direct Assessment”, PS-03-01-238: “Dry Gas Internal Corrosion Direct Assessment”, PS-03-01-240: “SCC Direct Assessment”).

Other assessment methods may be used if they are industry recognized and approved. CenterPoint Energy uses Procedure PS-03-01-224: “Assessment Methods Selection Process” to determine the most appropriate assessment technique to use on any pipeline segment.

The following figure provides a graphical flow of terminology for In-line inspection and direct assessment integrity assessments.



6.3.1.1 Pipeline In-Line Inspections

In-Line Inspection (ILI) is used to locate and characterize indications in a pipeline segment that may require further evaluation. The effectiveness of In-Line Inspection methods depends on the condition of the pipeline segment and how well the inspection tool matches the requirements set by the inspection objectives. ILI results characterize the indications with some detail. CenterPoint Energy developed the "Perform Planned Assessments – In-line Inspection (ILI)" process (PS-03-01-130) to define how ILI assessments are managed within the Company.

Procedure PS-03-01-244: "In-line Inspection and Analysis" provides detailed procedural information.

The Company will select an ILI tool suitable to assess the threats present on the pipeline segment.

6.3.1.2 Pressure Testing

Pressure testing follows the guidelines established in ASME B31.8 and in 49 CFR 192 Subpart J. All pressure testing is conducted according to Book 2, Manual of Construction Specifications, Procedure No. 47: "Pipeline Pressure Testing" which incorporates all of the guidelines in ASME B31.8. Process PS-03-01-135: "Perform Planned Assessment – Pressure Test" sets the parameters for managing pressure testing assessments.

Pressure testing is required to address pipe seam concerns when raising the MAOP of a pipeline or when raising the operating pressure above the historical operating pressure (highest pressure recorded in the past five years).

6.3.1.3 Direct Assessment

Direct assessment is a method that integrates knowledge of the physical characteristics and operating history of the pipeline with the results of inspections, examinations, and evaluations to determine pipeline integrity.

Direct assessment is appropriate for determining pipeline integrity with regard to internal or external corrosion and stress corrosion cracking. Direct assessment is typically not used for assessing other threats that are listed in section 6.1.2.

Process PS-03-01-140: “Perform Direct Assessment Inspection and Repair” describes how direct assessments are managed at CenterPoint Energy. The specific details are in Procedure PS-03-01-232: “External Corrosion Direct Assessment”, PS-03-01-238:”Dry Gas Internal Corrosion Direct Assessment”, PS-03-01-240: “SCC Direct Assessment”.

6.3.1.4 Other Integrity Assessment Methodologies

CenterPoint Energy stays abreast of technological developments in the industry and incorporates other assessment methodologies into its array of assessment tools as they are developed and tested for effectiveness.

6.3.2 Direct Assessment Plan

CenterPoint Energy’s direct assessment procedures describe when direct assessment methodologies may be used and the specific methods associated with the plan. The direct assessment plan was developed in accordance with ASME/ANSI B31.8S and NACE recommended practices. The procedures describe how and where direct assessment may be used. The procedures also detail the specific processes for ECDA, ICDA and SCCDA.

6.3.2.1 External Corrosion Direct Assessment

External corrosion direct assessment (ECDA) consists of four major components: pre-assessment, indirect inspections, direct examinations, and post-assessment. Procedure PS-03-01-232: “External Corrosion Direct Assessment” contains the specifics for each component.

6.3.2.2 Dry Gas Internal Corrosion Direct Assessment

Dry Gas Internal Corrosion Direct Assessment (DGICDA) contains four components: pre-assessment, identification of DGICDA regions and excavation locations, direct examination and post-assessment. Procedure PS-03-01-238: “Dry Gas Internal Corrosion Direct Assessment” contains the specifics for each component.

6.3.2.3 Stress Corrosion Cracking Direct Assessment

Stress corrosion cracking direct assessment (SCCDA) is used for two types of stress corrosion cracking: high pH, and near-neutral. There are three components: gather, review and integrate data; criteria and risk assessment; and integrity assessment. The details are provided in Procedure PS-03-01-240: “SCC Direct Assessment”.

6.3.2.4 Confirmatory Direct Assessment

Confirmatory direct assessment (CDA) may be used to reassess two potential threats: external corrosion and internal corrosion. The details are contained in Procedure PS-03-01-260: “Continual Process for Evaluation and Assessment”.

6.3.3 Low Stress Reassessment

A low-stress pipeline segment is defined as a segment that operates below 30% of Specified Minimum Yield Strength (SMYS). After completion of the initial baseline assessment, reassessment for low stress covered segments may be by indirect methods as follows:

Segments affected by external corrosion will be reassessed at least every seven years using an electrical survey. The survey results will be incorporated into the overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation will consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. If the pipe is unprotected or cathodically protected where electrical surveys are impractical, the Company will: (1) conduct leakage surveys as required at 4-month intervals; and (2) identify and remediate areas of active corrosion every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment.

Segments that are affected by internal corrosion will undergo a gas analysis for corrosive components and the fluids from appropriate storage fields will be analyzed for corrosive components at least annually. This testing data will be integrated at least every seven years into applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, and exposed pipe reports to determine and implement appropriate remediation actions.

Procedure PS-03-01-260: "Continual Process for Evaluation and Assessment" addresses low stress pipe reassessment.

6.3.4 Implement Repairs and Mitigation Based on Assessment

Responses to indications detected via integrity assessment methodologies may include repairs, preventive measures, and establishment of inspection intervals. Responses are selected to achieve risk reduction for a given pipeline segment. Reference Procedure PS-03-01-250: "Pipeline Evaluation and Remediation" and Procedure PS-03-01-252: "Schedule of Repair Requirements" for detailed procedural information.

6.3.4.1 Response to Pipeline In-Line Inspection

Responses will depend on the severity of the indication and will consider prior risk assessment efforts for the same pipeline segment. Three responses are possible:

- Immediate – indication that the segment is at or near a failure point
- Scheduled – indication that the segment has a significant problem, but not at failure point
- Monitored – indication that the segment will not fail before next scheduled inspection

All responses requiring an "Immediate" response will result in an immediate pressure reduction or pipeline segment shutdown until the repairs are completed. All other responses are prioritized and an action schedule is developed within 180 days of the inspection. The process PS-03-01-145: "Post In-Line Inspection (ILI) Repair", contains details for completing repairs following assessment.

6.3.4.2 Response to Pressure Testing

Pressure test failures are addressed by replacement of the failed pipe section.

6.3.4.3 Response to Direct Assessment

Dig locations will be selected per the procedures for ECDA, ICDA and SCCDA. The pipe at these locations will be inspected and, if required, repaired per Company procedures.

6.3.4.4 Repair Methods

CenterPoint Energy has a list of acceptable repair methods that follow established industry-accepted guidelines. These procedures are found in the Company's Operations & Maintenance Manual, Book 1, Procedure 226: Pipeline Repairs – Existing In Service Pipelines.

6.3.4.5 Prevention and Mitigation Strategy/Methods

Prevention and mitigation are important proactive elements of CenterPoint Energy's Integrity Management Program. Detailed information is provided in Procedures PS-03-01-258: "Preventive and Mitigative Measures" and PS-03-01-254: "Threat Prevention and Repair Chart".

Prevention and mitigation strategies are based on system data, identified threats, and risk assessments performed for each pipeline segment within CenterPoint Energy's pipeline system.

Industry accepted prevention and mitigation options include:

- Preventing third-party damage
- Controlling corrosion:

  - Internal (PS-03-02-120: “Internal Corrosion Control)
  - External (PS-03-02-100: “External Corrosion Control-Buried Pipe)
  - External (PS-03-02-110: “External Corrosion Control-Atmospheric)

- Detecting unintended releases

- Minimizing the consequences of unintended releases

Aside from the general prevention strategies described above, CenterPoint Energy will consider additional prevention/mitigation measures to prevent failure and mitigate the consequences of a pipeline failure in an HCA. These additional measures may include installing automatic shut-off valves or remote control valves, installing computerized monitoring and leak detection systems, replacing pipe segments with heavier pipe-wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders, and implementing additional inspection and maintenance programs.

6.4 POST-ASSESSMENT

Following completion of the assessment plan, inspections, and repairs, a formal review of the findings and conclusions is conducted. The results will be reflected in the specific plan for the segment, the overall IMP, or the processes and procedures of the IMP.

6.4.1 Evaluate Findings and Conclusions from Assessment

The documentation is reviewed upon completion of the assessment and any subsequent repairs and mitigation. This information is used to formulate findings and conclusions from implementing the IMP for a specific segment. A formal document is prepared to capture the findings and conclusions as well as any appropriate recommendations. Data from this activity are integrated with the segment data maintained in the pipeline integrity database.

6.4.2 Integrate Findings/Analysis into Risk Assessment and Threat Analysis

The results, findings, and conclusions from the assessment are reviewed to determine whether they indicate an apparent change or improvement that can be incorporated into the Risk Assessment and/or Threat Analysis Processes. Post-evaluation of a single segment may provide some insight; however, it is most likely that similar results from several assessments will be necessary to support a recommended change/improvement. Recommendations and supporting documentation are reviewed for further action with respect to the Risk Assessment or Threat Analysis processes.

6.4.3 Determine Reassessment Schedule for Each Segment

Based on the findings and conclusions from the post-assessment, the schedule for the next assessment for a pipeline segment is determined. This schedule is reviewed and incorporated into the long-term assessment plan and schedule. Integrity assessment intervals are scheduled to meet or exceed the criteria specified in ASME B31.8S as shown in the following table.

Integrity Assessment Intervals
Time-Dependent Threats Prescriptive Integrity Management Plan

		CRITERIA		
Inspection Technique	**Interval Years (Note 1)**	**At or above 50% SMYS**	**At or above 30% up to 50% SMYS**	**Less than 30% SMYS**
Hydrostatic Testing	5	TP to 1.25 times MAOP (Note 2)	TP to 1.4 times MAOP (Note 2)	TP to 1.7 times MAOP (Note 2)
	10	TP to 1.39 times MAOP (Note 2)	TP to 1.7 times MAOP (Note 2)	TP to 2.2 times MAOP (Note 2)
	15	Not Allowed	Not Allowed	TP to 2.8 times MAOP (Note 2)
	20	Not Allowed	Not Allowed	TP to 3.3 times MAOP (Note 2)
In-line Inspections	5	PF to 1.25 times MAOP (Note 3)	PF to 1.4 times MAOP (Note 3)	PF to 1.7 times MAOP (Note 3)
	10	PF to 1.39 times MAOP (Note 3)	PF to 1.7 times MAOP (Note 3)	PF to 2.2 times MAOP (Note 3)
	15	Not Allowed	Not Allowed	PF to 2.8 times MAOP (Note 3)
	20	Not Allowed	Not Allowed	PF to 3.3 times MAOP (Note 3)
Direct Assessment	5	Sample of indications examined (Note 4)	Sample of indications examined (Note 4)	Sample of indications examined (Note 4)
	10	All indications examined (Note 4)	Sample of indications examined (Note 4)	Sample of indications examined (Note 4)
	15	Not Allowed	All indications examined	All indications examined
	20	Not Allowed	Not Allowed	All indications examined

NOTES:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Time-dependent failures require immediate reassessment of the interval.

(2) TP is test pressure.

(3) PF is Predicted Failure pressure per ASME B31G or equivalent.

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals allow sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for reinspection is 5 years for pipes operating at or above 50% SMYS and 10 years for pipe operating below 50% SMYS.

6.4.4 Update Integrity Management Plan for Specific Segment

The post-assessment documentation and reassessment schedule information are used to update the assessment plan for that segment. The update reflects the assessment and repairs that were performed, the findings and conclusions from the post-assessment, and the recommendations. The assessment plan for the segment is updated to incorporate future assessment activity.

The process PS-03-01-150: "Post Assessment" describes the evaluation and integration of the aggregate results from the integrity assessment and response inspections, repairs, and mitigations. These findings and conclusions enhance the risk and threat models as well as assessment procedures.

7.0 PERFORMANCE PLAN

CenterPoint Energy has developed performance measures to evaluate the effectiveness of the Integrity Management Program. An annual evaluation is performed to determine if objectives of the program are being met and if the pipeline integrity and safety were improved through the program.

7.1 DEVELOPMENT OF PERFORMANCE MEASURES

The performance measures are selected to provide the Company with indicators of effectiveness but are not absolute. The trends indicate the overall program effectiveness over the short-term and long-term. Performance measures may be leading indicators or lagging indicators. Leading indicators provide a measure of how well the program is expected to work and lagging indicators indicate past performance.

7.2 INTERNAL PERFORMANCE MEASUREMENT

Internal performance metrics evaluate threat-specific conditions and overall integrity program performance. In addition to the threat-specific metrics listed in the table, the following program measurements will be determined and documented. These four program measures, and other applicable measures, will be calculated and reported on a semi-annual basis (as of June 30 and December 31 of each year). Reports will be submitted to the OPS by August 31 and February 28 or 29 of each year. Procedure PS-03-01-262: “Methods to Measure Program Performance” provides details of performance measurement:

- Number of miles of pipeline inspected versus program requirements
- Number of immediate repairs completed as a result of the Pipeline Integrity Management Program
- Number of scheduled repairs completed as a result of the Pipeline Integrity Management Program
- Number of leaks, failures, and incidents

Threats	Performance Metric
External corrosion	• Number of hydrostatic test failures caused by external corrosion • Number of repair actions taken due to ILI results • Number of repair actions taken due to DA • Number of external corrosion leaks
Internal corrosion	• Number of hydrostatic test failures caused by internal corrosion • Number of repair actions taken due to ILI results • Number of repair actions taken due to DA results • Number of internal corrosion leaks
Stress corrosion cracking (SCC)	• Number of in-service leaks or failures due to SCC • Number of repairs/replacements due to SCC • Number of hydrostatic test failures due to SCC
Manufacturing	• Number of hydrostatic test failures caused by manufacturing defects • Number of leaks due to manufacturing defects
Construction	• Number of leaks or failures due to construction defects • Number of girth welds/couplings reinforced/removed • Number of wrinkle bends removed • Number of wrinkle bends inspected • Number of fabrication welds repaired/removed
Equipment	• Number of regulator valve failures • Number of relief valve failures • Number of gasket or o-ring failures • Number of leaks due to equipment failure
Third-party damage	• Number of leaks or failures caused by third-party damage • Number of leaks or failures caused by previously damaged pipe • Number of leaks or failures caused by vandalism • Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect operations	• Number of leaks or failures caused by incorrect operations • Number of audits/reviews conducted • Number of findings per audit/review classified by severity • Number of changes to procedures due to audits/reviews
Weather-related and outside forces	• Number of leaks that are weather-related or due to outside forces • Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

7.3 INDUSTRY PERFORMANCE MEASUREMENT

Industry performance measurements consist of comparing CenterPoint Energy's performance measures to industry-published performance measures and conducting periodic benchmarking studies with other Pipeline Operators.

7.4 PERFORMANCE IMPROVEMENT

All the information gathered from performance measurements determines the effectiveness of CenterPoint Energy's program. The results of the evaluation are used to develop recommendations for changes and/or improvements to the Company's Integrity Management Program. The results, recommendations, and changes are documented.

8.0 COMMUNICATIONS PLAN

Communications are a key component of CenterPoint Energy's Integrity Management Program. Internal communications help ensure that the Company's employees have current information about the pipeline system and the Integrity Management Program. External communications with regulatory entities are required to keep interested parties aware of CenterPoint Energy's efforts regarding system integrity.

8.1 INTERNAL COMMUNICATIONS

The intent of CenterPoint Energy's internal communications is to ensure that management and operations personnel who are involved in or affected by the IMP are aware of the program's requirements, any changes to the program, the results of implementing integrity management, and specific performance measures. This information will be communicated through routine employee meetings, periodic written documents, and established corporate communications, such as newsletters, the Company intranet, etc.

8.2 EXTERNAL COMMUNICATIONS

CenterPoint has developed a Public Awareness Program that targets specific audiences for communication of pipeline safety information and identifies the kind of information that is communicated to each of the different audiences. The procedure PS-03-01-264: "IMP Communication Plan" augments the Public Awareness Program by providing supplemental information to the audiences specifically about CenterPoint Energy's Integrity Management Program. Communication with the target audiences is implemented through the Company's Public Awareness Program.

CenterPoint Energy's goal is to communicate its efforts, with regard to integrity management, to outside parties. A summary of those efforts is provided below:

- Local and regional emergency responders
    - Location of transmission pipelines that cross their area of jurisdiction, and how to get detailed information regarding those pipelines
    - CenterPoint Energy's emergency contact information
    - Information about the potential hazards of the pipelines

- How to contact CenterPoint Energy regarding questions and concerns with pipeline safety
- How to safely respond to a pipeline emergency
- How CenterPoint Energy prevents accidents and mitigates the consequences of accidents when they occur
- Summary of CenterPoint Energy's Pipeline Integrity Management Program

• Other public entities

- Information regarding pipelines that cross their area of jurisdiction
- Land-use practices associated with the pipeline right-of-way that may affect community safety
- Hazards associated with unintended releases
- How CenterPoint Energy prevents accidents and mitigates the consequences of accidents when they occur
- How to contact CenterPoint Energy regarding pipeline safety
- Summary of CenterPoint Energy's Pipeline Integrity Management Program

• Landowners and Tenants along the rights-of-way

- Notification that they live or work near a pipeline
- Hazards associated with unintended releases
- How CenterPoint Energy prevents accidents and mitigates the consequences of accidents when they occur
- How to recognize and respond to a pipeline emergency
- What protective actions to take in the unlikely event of a release
- How to notify CenterPoint Energy regarding questions, concerns, or emergencies

  - How to assist in preventing pipeline emergencies by following safe excavation/digging practices and reporting unauthorized digging and suspicious activity

  - How community decisions about land use may affect community safety along the pipeline right-of-way

  - How individuals can create encroachments upon a pipeline right-of-way

  - Summary of CenterPoint Energy's Pipeline Integrity Management Program

- General public

  - How CenterPoint Energy prevents accidents and mitigates the consequences of accidents when they occur

  - How to notify CenterPoint Energy regarding questions, concerns, or emergencies

  - Information regarding CenterPoint Energy's participation in the one-call initiatives that support excavation notifications and other damage prevention programs

  - Contact information with the company name and phone number applicable to the area the pipeline is located

8.3 OFFICE OF PIPELINE SAFETY

Notifications to the Office of Pipeline Safety (OPS) will be accomplished by one of the following methods as appropriate to the situation:

1. Send notification via U.S. Mail to the

   Information Resource Manager, Office of Pipeline Safety

   Research and Special Programs Administration

   US Department of Transportation, Room 7128

   400 Seventh Street SW

   Washington, DC 20590

2. Send notification via facsimile to the Information Resource Manager at (202) 366-7128.

3. Send notification via the website at http://primis.rspa.dot.gov/gasimp/. Enter the information in the integrity management database (IMDB).

Performance reports will be filed using methods 1 & 2 listed above or using the website below:

1. Send the information via the website for OPS electronic reporting at http://ops.dot.gov. Enter the information in the IMDB.

Some notifications to the OPS are also required to be sent to State or local pipeline safety authorities when either a covered segment is located in a State where OPS has an interstate agent agreement or an intrastate covered segment is regulated by that State.

Generally, notifications to OPS have a 30-day reporting requirement. Items requiring OPS (and/or State and local notification) include:

- Significant changes to the integrity management program
- Changes in program implementation
- Changes in schedules
- Extension of pressure reductions beyond 365 days

OPS notification is required for use of alternate assessment technologies and is required 180 days prior to implementation.

Safety concerns may be raised by either the OPS or State or local pipeline safety authorities. These concerns will be addressed by the Director, Pipeline Integrity with appropriate input from Pipeline Integrity Department personnel and other Company departments, responses developed, and forwarded to the Senior Director, Strategy and Support Services for transmittal to the regulatory authority. If the concern results in actions that change the IMP, including plans, schedules, or procedures, etc., the concern will be processed through the Management of Change program.

9.0 MANAGEMENT OF CHANGE PLAN

The management of change plan is designed to ensure that changes impacting the pipeline system and its integrity are identified and well-managed. The goal of managing change is to ensure that employees, contractors, vendors, and other concerned parties are aware of any changes that may impact them and the safe, reliable operation of CenterPoint Energy's pipeline system.

There are three categories of documents that are covered in the overall management of change plan for the Integrity Management program: program administration and control documents, data and records generated by the program, and reports generated outside the program.

The documents that administer and control the Integrity Management Program are critical to the success of the program. The CenterPoint Energy Management of Change process is a structured process that ensures proposed changes to the Program Description Document, Processes, Procedures, Plans and other similar documents are well-thought-out, deliberate, planned and necessary for the continued proper functioning of the overall program.

A separate change log process will be used for tracking and notification of changes to data and similar records generated through the various program processes.

The Company's Management of Change process and Procedure PS-03-01-266 "IMP Management of Change" provide the details of management of change.

For data and other information generated by the Company outside of the Integrity Management Program, but necessary to the operation of the program, reports will be generated and issued on a regular basis for updating the Integrity Management Program information base.

The following table describes the three segments of the management of change plan.

<table>
<tr><th>Document/Information Category</th><th>Change Management Method</th></tr>
<tr><td>Documents that administer and control the Integrity Management Program
Program Description Document
Implementing Procedures
Processes
Plans</td><td>Company Management of Change Program
Process Coordinator
Management Team
Oversight Group
Change Request Form
Description
Justification
Impact
Change Status List
Management Review and Approval
Training and Implementation</td></tr>
<tr><td>Information generated within the Program</td><td>Change Logs maintained for the following documents and data:
HCA Segments
Risk Model
Long Term Assessment Plan
Segment IM Plan
Class Change
MAOP Change
Separate change logs are maintained for each discrete type of document and record the date, description, originator, and approval for each change. The log also indicates the notification requirements.</td></tr>
<tr><td>Information generated outside the Program</td><td>New or changed information about the pipeline and surrounding environment is obtained from routinely generated reports:
Facility additions and replacements
Leaks, Failures and Third Party damage
Pipe Inspection Results
Gas Control Reports</td></tr>
</table>

10.0 QUALITY ASSURANCE PLAN

Quality assurance ensures that program actions and activities meet the requirements of the Integrity Management Program. The minimum requirements of CenterPoint Energy's quality control program are documentation, implementation, and maintenance.

The specific elements that comprise the quality assurance plan are:

- Specific documentation requirements (Section 4.0 of this Program document)
- Management and employee responsibilities (Section 3.0)
- Review of integrity assessment results (Section 6.4)
- Qualification of responsible employees (Section 5.0)
- Performance measurement of effectiveness (Sections 7.1 and 7.2)
- Periodic internal audits (Section 10.0)
- Implementation of corrective actions to improve the effectiveness of the overall plan (Section 10.0)

CenterPoint Energy has developed a compliance plan that outlines the need and schedule for conducting audits to ensure compliance with both the Integrity Management Program and federal regulations.

The Director, Pipeline Integrity ensures compliance with the overall Integrity Management Program by conducting periodic audits for each element of the program.

As required, the Director, Pipeline Integrity schedules additional audits to ensure compliance with the overall plan. The audits identify both noncompliance issues and opportunities to improve the overall effectiveness of the plan.

Deficiencies and improvement opportunities identified in the audit will be logged and a corrective action plan identified and tracked until implementation is complete.

Procedure PS-03-01-268: "IMP Quality Assurance", describes the quality assurance plan.

11.0 GLOSSARY AND ACRONYMS

Term	Abbreviation	Definition
Alignment Sheets		Maps showing detailed location of pipelines, facilities and other Company assets such as valve sites, rectifiers with respect to roads, railroads, streams, rivers, lakes, foreign pipelines, utilities, mileposts, aerial markers, utilities, etc.
Alternating Current Voltage Gradient	ACVG or A-Frame	A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.
Anomaly		A potential deviation from sound pipe material or weld. The indication may be generated by non-destructive inspection, such as in-line inspection.
Anode		An electrode at which oxidation of the surface or some component of the solution is occurring. Practically, this is the electrode at which corrosion occurs.
Assessment		The use of nondestructive techniques to determine the condition of a covered pipeline segment.
Asset Inventory Database		Within the context of the CenterPoint Integrity Management Program, the "Asset Inventory Database" is comprised of three components of the corporate database structure. PODS (Pipeline Open Data Structure) is a commercial software package that provides a consistent structure for storage and maintenance of certain data that pertains to pipe, pipeline components, and pipeline facilities. For example, pipe diameter, wall thickness, MAOP, pressure test data, valve type, year installed, are typical of the types of data maintained in PODS. MAXIMO is also a commercial software package expressly designed as a maintenance management program. MAXIMO is used to maintain information about equipment performance, repair history, and maintenance requirements and is also used to generate preventive maintenance schedules. The third component is a document database that is used to maintain MS Word documents such as memos, notes, analyses, justifications, and electronic forms; MS Excel spreadsheets; other work product files produced with commercial PC-based computer software; and also scanned images of items such as handwritten notes, manually filled in forms, and marked up drawings.
B31G	B31G	A method (from the ASME standard) of calculating the pressure carrying capacity of a corroded pipe.
Bell Hole		An excavation that minimizes surface disturbance yet provides sufficient room for examination or repair of buried pipelines.
Black on White MPI	BWMPI	A magnetic particle inspection (MPI) technique that uses a suspension of black magnetic iron particles that are applied on a white painted pipeline surface in the presence of a magnetic field.

Term	Abbreviation	Definition
Cathode		An electrode at which reduction is occurring. Practically, this is the electrode at which protection occurs in a cathodic protection system.
Cathodic Disbondment		The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.
Cathodic Protection	CP	A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.
Cathodic Protection System		This is a total facility designed to provide cathodic protection to a pipeline or related facility, that will consist of a direct current power source, ground bed and related wiring that connects the direct current power source to the structure to be protected and the ground bed. It is typically know as an impressed current system.
Class 1		A Class 1 location is an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy.
Class 2		A Class 2 location is any class location unit that has more than 10 bur fewer than 46 buildings intended for human occupancy.
Class 3		1. Any class location unit that has 46 or more buildings intended for human occupancy. 2. An area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). 3. When a cluster of buildings intended for human occupancy requires a Class 3 location, the class location ends 220 yards from the nearest building in the cluster.
Class 4		1. A Class 4 location is any class location unit where buildings with 4 or more stories aboveground are prevalent. 2. The length of Class locations 2, 3, and 4 may be adjusted as follows: • A Class 4 location ends 220 yards from the nearest building with four or more stories aboveground.
Cleaning Pig		A utility pig that uses cups, scrapers, brushes, or magnets to remove dirt, rust, mill scale, and other liquid or solid matter from the pipeline.
Close Interval Survey	CIS	A method of measuring the electric potential between the pipe and earth at regular intervals along the pipeline.
Cluster		A grouping of stress corrosion cracks (colony). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area.
Coating System		The complete number and types of coats applied to a substrate in a predetermined order. When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.

Term	Abbreviation	Definition
Colony		A grouping of stress corrosion cracks (cluster). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area.
Compressibility Factor (Z)	Z	The compressibility factor is the ratio of the actual volume of a given mass of gas at a specified temperature and pressure to its volume calculated from the ideal gas law under the same conditions. Used in the calculation of gas flow and pipe inclination angles when conducting the ICDA assessment process.
Confirmatory Direct Assessment	CDA	An assessment method using more focused applications of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.
Consequence		The impact that a pipeline failure could have on the public, employees, property, and the environment.
Covered Segment or Covered Pipeline Segment		A segment of transmission gas pipeline located in a high consequence area.
Critical Inclination Angle		The lowest angle at which liquid carryover is not expected to occur under stratified flow conditions.
Current Attenuation Survey		A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, anomaly location, and anomaly type.
Defect		An imperfection exceeding acceptable criteria.
Defined Length		Any length of pipe until a new input or output changes the potential for electrolyte entry or changes the flow characteristics.
Detailed Examination		Examination of the pipe wall at a specific location to determine whether metal loss from corrosion has occurred. The examination is typically performed using non-destructive inspection techniques such as visual, ultrasonic, radiographic, or other means.
Direct Assessment	DA	A structured process for assessing the integrity of buried pipelines.
Direct Current Voltage Gradient	DCVG	A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize coating activity.
Disbonded Coating		Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday.
Double Submerged Arc Weld	DSAW	A type of welding process used in fabrication of pipe
ECDA Region		A section or sections of a pipeline that have similar physical characteristics and operating history and in which the same indirect inspection tools or methods are used.

Term	Abbreviation	Definition
Electric Resistance Welded Pipe	ERW Pipe	A method of welding the long seam of a pipe during manufacture in which the two sides of the seam are first heated by the application of an electric current and then forced together to form a bond.
Electrolyte		A fluid substance through which electrical charge is carried by the movement of ions. Water is a common electrolyte.
Evaluation		The analysis and determination of a facility's fitness for service under the current operating conditions.
Examination		Physical inspection of the pipelines by a person. May include the use of nondestructive examination techniques.
External Corrosion Direct Assessment	ECDA	A four-step process that combines pre-assessment, indirect inspections, direct examinations, and post assessment to evaluate the impact of external corrosion on the integrity of a pipeline.
Failure		A general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously to the point that it has become unreliable or unsafe for continued use.
Fusion Bonded Epoxy	FBE	An epoxy based material used to coat the exterior of pipes for protection from the environment.
Gauging or Plate Pig		A utility pig that is typically configured with a metal plate with a diameter slightly less than the inside diameter of the pipeline that is permanently deformable by obstructions in the pipeline. The deformable plate provides evidence of the worst-case obstruction in a given pipeline segment.
Geometry Pig		An instrumented pig designed to record pipe wall contour conditions, such as dents, gouges, ovality, wrinkles, and bend radius by making measurements of the inside surface of the pipeline.
Geographical Information System	GIS	A mapping information system
Global Positioning System	GPS	A system used to identify the latitude and longitude of locations on Earth using geo-stationary satellites.
Girth Weld		The circumferential weld that joins two sections of pipe
Gouge		A surface imperfection caused by mechanical damage that reduces the wall thickness of a pipe or component

Term	Abbreviation	Definition
High Consequence Area	HCA	An area established by one of the methods described in (a) or (b) below. (a) An area defined as: (1) a Class Location 3 under 192.5; or (2) a Class Location 4 under 192.5; or (3) any area outside a Class 3 or Class 4 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or (4) the area within a potential impact circle containing an identified site. (b) The area within a potential impact circle containing (1) 20 or more buildings intended for human occupancy, unless the exception in paragraph (d) applies; or (2) an identified site. (c) Where a potential impact circle is calculated under either method (a) or (b) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (d) If in identifying a high consequence area under paragraph (a)(3) or paragraph (b)(1), the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If the operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to [20 x (660 feet [or 200 meters]/potential impact radius in feet [or meters])^2]).
High pH SCC		A form of stress corrosion cracking (SCC) on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3)
Holiday		A discontinuity (hole) in a protective coating that exposes unprotected surface to the environment.
Hoop Stress		Circumferential stress in a pipe or pressure vessel that results from the internal pressure.
Hydrostatic (or Pressure) Test		Proof testing of sections of a pipeline by filling the line with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

Term	Abbreviation	Definition
ICDA Region		A continuous length of pipe (including weld joints) uninterrupted by any significant changes in electrolyte or flow characteristics that includes similar physical characteristics and operating history.
ICDA Subregion		A continuous length of pipe (including weld joints) contained in a region, defined as the pipe length between two inclination angles at which corrosion is found or the start of the region and the first inclination angle at which corrosion is found.
Identified Site	IS	Each of the following areas: (a) An outside area that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) months (the days need not be consecutive). (Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or (b) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive). (Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks); or (c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, daycare facilities, retirement facilities, or assisted-living facilities.
In-Line Inspection	ILI	The inspection of a pipeline from the interior of the pipe using and in-line inspection tool. The tools used to conduct ILI are known as pigs or smart pigs.
Incident		An unintentional release of gas due to a failure.
Inclination Angle		An angle resulting from a change in elevation between two points on a pipeline, in degrees.
Indication		A finding by a nondestructive testing technique that may or may not be a defect.
Indirect Inspection		Use of tools to indirectly examine a pipeline. This includes monitoring (for example, sampling or coupons/probes) and inspection methods (for example, ultrasonics, radiography, or in-line inspection).
Inspection		1. A systematic physical examination of a site or facility. 2. Within the context of indirect inspection, the use of a nondestructive testing technique such as in-line inspection, DCVG, CIS, PCM, magnetic particle inspection, dye penetrant inspection, etc.
Integrity Management Program	IMP	A program consisting of a program description and implementing procedures that prescribes a systematic process for the continual assessment of the integrity of a pipeline. The program also provides for the mitigation of threats to the pipeline and remediation of defects in the pipeline that degrade the safety and operability of the pipe.

Term	Abbreviation	Definition
Integrity Assessment		A process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, and characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis.
Internal Corrosion Direct Assessment	ICDA	ICDA is a process that identifies areas along a pipeline where water or other electrolyte introduced by an upset condition may reside inside the pipe, then focuses detailed examination on the locations in each area where internal corrosion is most likely to exist.
Intergranular Cracking		Cracking in which the crack path is between the grains in a metal. The phenomenon is associated with high pH SCC.
Leak		An unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks, separation or pull-out, and loose connections.
Liquid Holdup		Accumulation of liquid (that is, input liquid volume is greater than output liquid volume)
Magnetic Particle Inspection	MPI	A non-destructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field. In its simplest form a dry magnetic powder is dusted on the pipe in the presence of a magnetic field.
Maximum Allowable Operating Pressure	MAOP	The maximum internal pressure permitted during the operation of a pipeline.
Mechanical Damage		Anomalies in pipe, including dents, gouges, scratches, and metal loss, caused by the application of an external force.
Metallography		The study of the structure and constitution of a metal as revealed by a microscope.
Microbiologically Influenced Corrosion	MIC	Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.
Mitigation		The limitation or reduction of the probability of occurrence or expected consequence for a particular event.
Multiphase Flow		Flow involving more than one phase (for example, gas and liquid)
Near-neutral pH SCC		A form of stress corrosion cracking (SCC) on underground pipelines that is transgranular and is associated with a near-neutral pH electrolyte. Typically, this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface.
Nondestructive Examination	NDE	An inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic, and dye penetrant methods.

Term	Abbreviation	Definition
Office of Pipeline Safety	OPS	The Department of Transportation's Research and Special Programs Administration, acting through the Office of Pipeline Safety (OPS), administers the Department's national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline.
Operator Qualification	OQ	Qualification program for pipeline personnel.
pH	pH	The negative logarithm of the hydrogen activity written as: $pH = -\log_{10}(a_H^+)$ where a_H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion activity coefficient.
Potential Impact Circle	PIC	A circle with a radius equivalent to the potential impact radius.
Potential Impact Radius	PIR	The radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property. PIR is determined by the formula $r = 0.69 * \sqrt{(p \times d^2)}$ where, d = the nominal diameter of the pipeline in inches p = the pipeline segment's maximum allowable operating pressure in psi r = the radius of a circular area surrounding the failure in feet Note: 0.69 is the factor for natural gas. This number will vary for other gases depending on their heat of combustion. An operator transporting anything other than natural gas must use Section 3.2 of ASME/ANSI B31.8S-2001 to calculate the potential impact radius.
Probability		The likelihood of an incident occurring.
Profile Pig		A utility pig, similar to a gauging pig, configured with 3 or 4 various sized metal plates that provide evidence of the worst-case obstruction and worst-case bend radius in a given pipeline segment.
Remediation		A repair or mitigation performed on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences. Also, corrective actions taken to mitigate deficiencies in the corrosion protection system.
Risk		A measure of potential loss in terms of both the incident probability of occurrence and the magnitude of the consequence.
Risk Assessment		A systematic process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are estimated.

Term	Abbreviation	Definition
Risk Management		An overall program that identifies threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences, or both; and, measuring the risk reduction results achieved.
Root Cause Analysis		A family of processes implemented to determine the primary cause of an event. These processes all seek to examine cause and effect relationships through the organization and analysis of data. Such analyses are often used in failure analyses.
RSTRENG	RSTRENG	A computer program designed to calculate the pressure-carrying capacity of a corroded pipe.
Rupture		A complete failure of any portion of the pipeline characterized by a breach in the pipe wall.
Scraper Pig		A device that is inserted into a pipeline to literally scrape clean the inside walls of a pipe.
Segment		A length of pipeline or part of the system that has unique characteristics in a specific geographic location. In the context of ICDA, a portion or a pipeline that is assessed using ICDA. A segment may consist of one or more ICDA regions.
Significant SCC		An SCC cluster was defined to be “significant” by the Canadian Energy Pipeline Association (CEPA) in 1997 provided that the deepest crack in a series of interacting cracks is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria. The presence of extensive and “significant” SCC typically triggers an SCC mitigation program, but a crack that labeled “significant” is not necessarily an immediate threat to the integrity of the pipeline.
Smart Pig		An instrumented pig used for non-destructive internal in-line inspection of the pipe wall.
Sound Engineering Practice		Also referred to as sound engineering judgment or sound engineering analysis. Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.
Specified Minimum Yield Strength	SMYS	The specified minimum yield strength is the minimum yield strength of the steel in pipe as required by the pipe product specifications.
Stress Corrosion Cracking	SCC	Brittle cracking of a normally ductile material caused by the conjoint action of a corrosive environment with tensile stress.
Stress Corrosion Cracking Direct Assessment	SCCDA	A direct assessment of stress corrosion cracking.
Superficial Gas Velocity		The volumetric flow rate of gas (at system temperature and pressure) multiplied by the cross-sectional area of the pipe.
Third-Party Damage		Damage to a pipeline facility by an outside party other than those performing work for the operator.

Term	Abbreviation	Definition
Transgranular Cracking		Cracking in which the crack path is through the grains of a metal. The phenomenon is associated with near-neutral pH SCC.
Transmission System		One or more segments of pipeline, usually interconnected to form a network, which transport gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high- or low-pressure distribution system, a large volume customer, or another storage field.
Wet Fluorescent MPI	WFMPI	A magnetic particle inspection (MPI) technique that uses a suspension of magnetic particles that are fluorescent and visible with an ultraviolet light.
Wet Visual MPI	WVMPI	A magnetic particle inspection (MPI) technique that uses a suspension of magnetic particles that are visual with natural light.

12.0 REFERENCES AND STANDARDS

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- NACE Standard Recommended Practice RP0502-2002, Pipeline External Corrosion Direct Assessment Methodology
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- 49 CFR Part 192, Transportation of Natural and Other Gas by Pipeline
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Appendix A – List of Processes

PS-03-04-100	Population Density and HCA Field Survey Process
PS-03-01-105	HCA – Class Review
PS-03-01-115	Risk Assessment
PS-03-01-120	Develop Long-Term Assessment Plan
PS-03-01-125	Develop Annual Assessment Plan
PS-03-01-130	Perform Planned Assessment – In-Line Inspection (ILI)
PS-03-01-135	Perform Planned Assessment – Pressure Test
PS-03-01-140	Perform Direct Assessment Inspection & Repair
PS-03-01-145	Post In-Line Inspection (ILI) Repair
PS-03-01-150	Post Assessment

Appendix B – List of Procedures

Section 1.0 - Purpose and Objectives	
	No Applicable Procedures
Section 2.0 - Background	
	No Applicable Procedures
Section 3.0 - Management Accountability and Responsibility	
	No Applicable Procedures
Section 4.0 - Documentation	
PS-03-01-214	Data Management
Section 5.0 - Personnel Qualifications	
PS-03-01-272	IMP Personnel Qualification Requirements
Section 6.0 - Integrity Management Plan **Section 6.1 - Pipeline System Data Integration**	
PS-03-01-200	HCA Segment Identification
PS-03-01-210	HCA Segment Mapping Requirements
PS-03-01-214	Data Management
Section 6.2 - Risk Assessment and Inspection Schedule	
PS-03-01-216	Threat Identification and Risk Assessment
PS-03-01-220	Baseline Assessment Plan
PS-03-01-224	Assessment Methods Selection Process
PS-03-01-222	Baseline Assessment Inspection & Remediation Schedule
Section 6.3 - Implementation of Annual Assessment Plan	
PS-03-01-230	Direct Assessment Plan
PS-03-01-232	External Corrosion Direct Assessment
PS-03-01-238	Dry Gas Internal Corrosion Direct Assessment
PS-03-01-240	SCC Direct Assessment
PS-03-01-234	ECDA Data Elements Form
PS-03-01-239	DG-ICDA Data Elements Form
PS-03-01-242	Dig Data Sheet
PS-03-01-250	Pipeline Evaluation and Remediation

PS-03-01-258	Preventive and Mitigative Measures
Section 6.3 - Implementation of Annual Assessment Plan (cont'd)	
PS-03-01-254	Threat Prevention and Repair Chart
PS-03-01-252	Schedule for Repair Requirements
PS-03-01-244	In-line Inspection and Analysis
PS-03-01-246	Pipeline Pigging Questionnaire
PS-03-01-248	ILI Vendor Performance Specification
Book 2, Construction Specification, Procedure No. 47	Pipeline Pressure Testing
Book 1,O&M Manual, Procedure No. 226	Pipeline Repairs – Existing In Service Pipelines
Section 6.4 - Post Assessment	
PS-03-01-260	Continual Process for Evaluation and Assessment
Section 7.0 - Performance Plan	
PS-03-01-262	Methods to Measure Program Performance
Section 8.0 - Communications Plan	
PS-03-01-264	IMP Communication Plan
Section 9.0 - Management of Change Plan	
PS-03-01-266	IMP Management of Change
Section 10.0 - Quality Control Plan	
PS-03-01-268	IMP Quality Assurance
Section 11.0 - Glossary and Abbreviations	
	No Applicable Procedures
Section 12.0 - References and Standards	
	No Applicable Procedures

HCA IDENTIFICATION

INTRODUCTION

This process describes the steps for identifying new HCAs and changes to existing HCAs on a continual basis. The purpose of this process is to maintain up-to-date, current information about identified HCAs and to maintain a list of changes made to the HCA database over time.

The initial, or Baseline, list of HCAs was developed in 2004 and updated in 2005. The development of the Baseline HCA List was described in the document PS-03-01-200: "HCA Segment Identification", Revision 4, dated September 7, 2005, and PS-03-01-210: "HCA Segment Mapping Requirements", Revision 5, dated December 17, 2004. PS-03-01-200 has been revised and PS-03-01-210 is a historical document and is no longer in use.

This outline describes five processes:

- Process A - HCA changes due to population density changes
- Process B - HCA changes due to changes to MAOP and to pipeline facilities
- Process C - HCA changes due to internet searches
- Process D - HCA changes due to local emergency official contact
- Process E - Approval of HCA changes
- Process F - Process review

PROCESS

Step Action and Discussion

Process A - Population Density Review and HCA Field Survey

Process A is an annual review performed on a routine monthly basis in association with line patrols such that the entire pipeline transmission system is reviewed at least once annually for changes to existing HCAs and identification of new HCAs.

1 Issue the Population Density and HCA Field Survey Alignment Sheets to Field Teams.

a) Primary responsibility: Engineering & Compliance - Data Integrity.

b) Follow Book 1, O&M Manual, O&M Procedure 219: "Population Density and HCA Field Surveys".

c) Line patrols of pipeline system segments are performed monthly. Data Integrity prints out and transmits alignment sheets to the field based on the Population Density and HCA Field Survey schedule.

2 Verify that the Population Density and HCA Survey Sheets are scheduled, issued for updating, and completed sheets are received.

a) Primary responsibility: Engineering & Compliance - Data Integrity.

b) Verify that alignment sheets and population density survey sheets are scheduled and issued to Field Teams for completion.

c) Maintain a list of alignment sheets received back from Field Teams.

d) Transfer alignment sheets to Pipeline Integrity, Data Management Group, after documenting receipt from Field Teams.

3 Perform field survey.

a) Primary responsibility: Field Teams.

b) Collect data.

c) Follow Book 1, O&M Manual, O&M Procedure 219: “Population Density and HCA Field Surveys”, for completing the Population Density and HCA Survey Sheets.

d) Follow procedure PS-03-01-200: “HCA Segment Identification”, for completing the Identified Site Information Sheet form.

e) Transmit completed forms to Data Integrity (see steps 2c and 2d).

4 Perform quality control check on Step 2

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management

b) Perform quality control check that Population Density and HCA Survey Sheets have been scheduled, issued to the Field Teams, and completed sheets were received.

c) Document findings in ICAM.

5 Review revised data for possible HCA creation, deletion or boundary adjustment.

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management.

b) Verify PIR on Population Density and HCA Survey Sheets are correct. Use formula in Section 2.4, Procedure PS-03-01-200: “HCA Segment Identification”.

c) Review new Identified Site Sheets for creation of new HCAs.

d) Review existing HCA boundaries for changes due to:

- New structures
- Change in structure use
- Changes to pipeline centerline data

e) Identify and record recommended changes in Population Density and HCA Survey Change Log.

6 Go to Process E

Process B - HCA changes due to changes to MAOP and to pipeline facilities

Process B is performed as required whenever changes to MAOP or to the pipeline facilities occur.

NOTE: MAOP changes are the primary responsibility of the Sr. Pipeline Integrity Engineer or Project Manager - MAOP and are resolved in accordance with PS 03-04-105: “MAOP Review”.

1 Receive notification of MAOP change.

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management.

b) Change notifications come from MAOP Process described in PS-03-04-105: “MAOP Review”.

c) Go to Step 3

2 Obtain notification of change to pipeline facilities

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management

b) Change notifications are identified through the AFE review process and review of construction records and work orders obtained from Operations and Engineering & Compliance - Project Management, or Data Integrity.

c) The Supervisor, Data Management may consult with the Sr. Pipeline Integrity Engineer concerning the HCA change caused by changes in pipeline facilities.

d) Go to Step 3

3 Determine HCA boundaries.

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management.

b) Recalculate PIR using formula in Section 2.4 in procedure PS-03-01-200: “HCA Segment Identification”.

c) Compare recalculated PIR and/or pipeline facility changes with known structures to determine new or revised HCA boundaries.

- Ensure that structure database is populated within the recalculated PIR and/or 660-foot boundary.

- For changes affecting existing HCAs, determine whether the HCA method of determination has changed (Method 1 or Method 2; see Procedure PS-03-01-200, Section 2.2).

d) Identify recommended changes to existing HCAs and/or the creation of new HCAs and record in Population Density and HCA Change Log.

4 Go to Process E.

Process C - HCA changes due to internet searches

Process C is performed biennially (occurring every two years).

1 Perform internet search.

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management.

b) Perform an internet search to identify and locate potential Identified Sites in accordance with Section 2.7 of Procedure PS-03-01-200: “HCA Segment Identification”.

c) Transmit internet search results to Field Teams for investigation (Process A, Steps 3a through 3e).

d) Evaluate the results of the Field Team investigations of the potential Identified Site to determine whether there is a change to an existing HCA or a new HCA, in accordance with Procedure PS-03-01-200: “HCA Segment Identification”.

e) Identify and record recommended changes in Population Density and HCA Survey Change Log.

2 Go to Process E.

Process D - HCA changes due to local emergency official contact

Process D is performed biennially.

1 Perform survey of local emergency officials for Identified Site information.

a) Primary responsibility: Pipeline Integrity - Supervisor, Data Management.

b) Transmit a form letter to local safety/emergency planning officials requesting information on changes to Identified Sites or information on new identified Sites.

- Identify local officials by zip code
- Include definition of Identified Site
- Include a due date for submittal of information

c) Receive and record responses.

d) Transmit survey results to Field Teams for investigation (Process A, Steps 3a through 3e).

e) Evaluate the results of the Field Team investigations of potential Identified Sites to determine whether there are new Identified Sites or changes to existing Identified Sites in accordance with Procedure 03-01-200: "HCA Segment Identification".

f) Identify and record recommended changes in Population Density and HCA Survey Change Log.

2 Go to Process E.

Process E - Approval of HCA changes

1 Review and approve recommended changes.

a) Primary responsibility: Manager, Pipeline Integrity.

b) Review and approve Population Density and HCA Change Log and return to Supervisor, Data Management for transmittal of HCA changes to Engineering & Compliance - Data Integrity for entry into the Asset Inventory Database.

c) Notify Sr. Pipeline Integrity Engineer of HCA change to perform a review for the need of remote control valves (RCV) or leakage detection systems.

2 Verify that changes to HCA database are made in the Asset Inventory Database.

a) Primary responsibility: Pipeline Integrity -- Supervisor, Data Management.

b) Verify all changes to HCA database in the Asset Inventory Database.

c) Document as complete in Population Density and HCA Change Log.

d) Compare entire HCA mileage in the Asset Inventory Database, before and after changes, to validate entire HCA database.

3 Go to Process F

Process F - Process Review

1 Review the process.

a) Primary responsibility: Process Owner

b) Review the following:

- Processes associated with this area
- Tasks associated with the various processes
- Supporting documentation requirements for the tasks associated with the processes
- Timelines associated with the various processes
- Roles associated with the various processes

c) Enter review results in ICAM

2 Resolve issues.

a) Primary responsibility: Process Owner

b) Resolve issues and discrepancies arising from the process review (Step 1) in accordance with the Process Outline for Management of Change.

THREAT IDENTIFICATION AND RISK ASSESSMENT PROCESS

INTRODUCTION

This process outline describes the steps necessary for conducting a review and update of identified pipeline integrity threats and assessment of pipeline risk. There are two processes described in this outline:

Process A - Annual Update
Process B - Process Evaluation and Improvement

FREQUENCY OF USE

This process is implemented on an annual basis, or as directed by the Director Pipeline Integrity or Manager, Pipeline Integrity. Progress during process implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

Process A - Annual Update

Step Action and Discussion

1 Review regulatory environment.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review related codes, standards, and regulations
- Identify changes since previous threat identification and risk assessment update.
- Document changes that need to be considered.

c) Identify and document impacts.
- Are there changes to the threat identification and risk assessment process that need to be implemented?
- Are there changes to the list of potential pipeline threats that need to be implemented?
- Are there changes to the Risk Model that need to be implemented?

d) This information will be used to update the Threat List and Consequence list.

2 Review industry knowledge base.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review published industry papers
   - Research papers and experience reports from industry trade groups, research companies, other gas transmission companies.
   - Review for new information (since previous threat identification/risk assessment update) concerning pipeline integrity threats, consequences, and risk assessment.

c) Identify and document potential impacts.
   - Are there impacts to the threat identification/risk assessment process that need to be considered?
   - Are there changes to the list of potential pipeline threats that need to be implemented?
   - Are there changes to the Risk Model that need to be implemented?

d) This information will be used to update the Threat List and Consequence List.

3 Update the Threat List.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) List of Threats was originally developed in accordance with Sections 2.2, 2.3 and 2.4 of Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.

c) Update the current Threat List.
   - Use the results of Steps 1 and 2 of this Process Outline.
   - Include input from the Process: “Continual Evaluation and Assessment”.
   - Review current Threat List to determine whether threats are no longer valid for the Company’s pipeline system.
   - Review current Threat List to determine whether there are new threats to be added to the List.
   - Document changes made to the Threat List.

4 Identify threats to Company’s pipeline system.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review Company's pipeline system to determine whether there are any segments susceptible to threats identified in the updated Threat List.
   - Consider interactive threats.
   - Document details of new threats (position paper).
   - Update threat list by pipeline segment.

5 Update the Consequence List.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Update the Consequence List.
   - Use information obtained in Steps 1 and 2 of this process outline.
   - Review current Consequence List to determine whether consequences are no longer valid for the Company's pipeline system.
   - Review current Consequence List to determine whether there are new consequences to be added to the List.
   - Document changes made to the Consequence List.

6 Identify consequences to Company's pipeline system.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review Company's pipeline system to determine whether there are any segments susceptible to consequences identified in the updated Consequence List.
   - Document details of new consequences (position paper).
   - Update Consequence List by pipeline segment.

7 Gather Data.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Identify and gather data.
   - Identify the data elements required to determine the susceptibility of the pipeline system to the updated Threat List.
   - Identify new data elements that can be used to improve the evaluation of existing threats.
   - Identify data sources for data elements required to analyze new and existing threats.
   - Collect and record the data.

c) Identify missing or unsubstantiated data.

d) Update the Missing Data Plan.
- Identify missing or unsubstantiated data.
- Identify changes to plan to collect missing and unsubstantiated data. Consider additional historical records review, field verification, subject matter experts, Maximo maintenance records.
- Document efforts to obtain missing data and efforts to verify unsubstantiated data.

8 Update the Risk Model.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) The risk assessment and risk model used to conduct the assessment are described in Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.

c) Update the risk assessment facilities database with current information. Identify and record database name and location.

d) Update the risk model configuration.
- Input new threats and associated data elements.
- Input new data elements for existing threats.
- Update algorithm based on feedback from previous assessments.
- Record the threats added to the Risk Model.
- Record the data elements added to existing threats.
- Record the Risk Model configuration changes made (if any).

9 Update the risk assessment.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Execute the Risk Model using the updated input data and changed configuration.

c) Determine whether Risk Model executed properly and document.

d) If Risk Model did not execute properly, identify issues and correct, re-run model, and document results.

10 Validate and publish the updated risk assessment.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Validate the risk assessment model run.
- Review using industry standards.
- Review using subject model experts.
- Document review results.

c) If Risk Model run cannot be validated, identify issues and correct, re-run model, and document results.

d) Notify Pipeline Integrity Supervisor, Data Management that updated Risk Assessment is available. Identify database name and location.

-- End of Process A --

Process B - Process Evaluation and Improvement

<u>Step</u> <u>Action and Discussion</u>

1 Review and evaluate the threat identification and risk assessment annual update process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review the overall process.
- All tasks necessary to implement the process are sufficiently identified.
- Additional tasks or supporting procedures are needed.

c) Describe the additional tasks or supporting procedures.

2 Review and evaluate the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review each task for completeness.
- Description of each task is sufficient.
- Additional details are needed to properly describe the task.
- Are new procedures needed to provide the details?

c) Describe the additional details needed.

3 Review and evaluate the referenced procedures that support the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review the procedures for completeness.
- Procedures are sufficient to support the tasks.
- Additional steps need to be added to the procedures.
- Additional procedures are needed.

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review the supporting documentation.
- Supporting documentation is sufficient.
- Additional supporting documentation is needed.
- Are additional forms needed?

c) Describe the additional supporting documentation needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review the timeliness for performing the tasks.
- On-time completion percentages were acceptable.
- On-time completion percentages were not acceptable.

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review the assigned primary responsibilities for each task.
- Assigned responsibilities are correct.
- Changes in assigned responsibilities are needed.

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
- Identify revised tasks and new tasks.
- Identify revised supporting procedures or new supporting procedures.
- Identify revised forms or new forms.
- Identify new supporting documentation and supporting documentation format changes.
- Identify changes to schedule for performing the process.
- Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process B --

INTRODUCTION

This process describes the tasks for updating the baseline assessment plan.

The original Baseline Assessment Plan was developed in 2004 and identified the High Consequence Areas (HCA) along each pipeline segment and the selected method of assessment. The Baseline Assessment Plan was a multi-year plan that was scheduled in accordance with the assessment completion requirements identified in Subpart O. Subsequent updates to the Baseline Assessment Plan are known as the Long-Term Assessment Plan.

The annual review and update is designed to capture changes resulting from new and changed HCAs, changes in threats and risk assessments, changes in types of assessments or new assessments, schedule progress changes and updates, and assessment results.

This outline contains three processes:

- Process A - Assessment method selection
- Process B - Scheduling of assessments
- Process C - Process review

FREQUENCY OF USE

The Long-Term Assessment Plan is reviewed and updated on an annual basis, or as directed by the Director, Pipeline Integrity or Manager, Pipeline Integrity. Progress during process implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

Step **Action and Discussion**

Process A - Assessment Method Selection

1 Obtain current results from risk model analysis.

a) Primary responsibility: Pipeline Integrity - Pipeline Integrity Engineer or Project Manager - BAP

b) The risk model is run annually to analyze identified threats to HCA pipeline segments to evaluate relative risk. The model output is sorted in descending risk. Refer to the Process Outline “Threat Identification and Risk Analysis” and Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.

c) A quality check that all changed and new HCAs have been included in the annual risk model analysis is performed by the Supervisor, Data Management in the Process Outline “Threat Identification and Risk Analysis” and is not necessary for this process outline.

d) Refer also to Section 2.3 in procedure PS-03-01-220: “Baseline Assessment Plan” for additional discussion concerning threat identification and risk assessment.

2 Evaluate new assessment methods.

a) Primary responsibility: Pipeline Integrity - Pipeline Integrity Engineer or Project Manager - BAP

b) Review new assessment methods developed by the pipeline industry for applicability to existing threats. Document the new methods that are available and their potential use.

c) Update the Assessment Selection form (PS-03-01-224: “Assessment Methods Selection Process”) to include new assessment methodologies, as appropriate.

3 Select assessment method.

a) Primary responsibility: Pipeline Integrity - Pipeline Integrity Engineer or Project Manager - BAP

b) Review existing assessment methods for continued applicability based on changes identified in Steps 1 and 2.

c) Review input from the Process: “Continual Evaluation and Assessment” concerning changes to assessment methods.

d) Refer also to Section 2.3 in procedure PS-03-01-220: “Baseline Assessment Plan” for additional discussion concerning selection of assessment method.

e) Use Assessment Selection Guide (PS-03-01-224: "Assessment Methods Selection Process") to identify the appropriate assessment method for new threats and new and changed HCAs.

- Record results using the Assessment Selection form.
- Based on newly identified threats, and threats to new and changed HCAs, review for unique segment situations not covered in the assessment selection flowchart:
  - Actions to address particular threats (e.g., ERW, manufacturing and construction defects, cyclic fatigue).
  - Interactive threats (e.g., cyclic fatigue with dents, wrinkle bends, girth weld defects; manufacturing defects with SCC or selective seam corrosion).

-- End of Process A --

Process B - Scheduling of Assessments

1 Review and update schedules for Long Term Assessment Plan.

a) Primary responsibility: Pipeline Integrity - Pipeline Integrity Engineer or Project Manager - BAP

b) Determine mileage of assessed pipeline segments needed per year to meet 10-year Subpart O requirement for completion of baseline assessments.

c) Determine schedule for assessing each covered segment considering the following parameters (this is an iterative process):

- 50 percent of assessments must be completed in five years (Subpart O)
- High risk segments to be scheduled first
- Pipeline modification schedule for ILI tool runs
- System Control capacity issues
- Resources (ILI vs. Direct Assessment vs. Pressure Test: ability to execute)
- ILI tool availability
- Seasonal issues
- Geographical constraints
- DOT notification requirements
- Re-assessment intervals

d) Develop the updated assessment plan and schedule using the assessment plan spreadsheet in procedure PS-03-01-222: "Baseline Assessment Plan Spreadsheet".

e) Re-sort HCA Segment Assessment Schedule list by year. Identify and record assessed mileage per year.

f) Identify changes to Long Term Assessment Plan and enter into BAP Change Log.

g) Submit recommended Long Term Assessment Plan for review and approval.

2 Review and approve updated Long Term Assessment Plan.

a) Primary responsibility: Manager, Pipeline Integrity

b) Review recommended Plan with Pipeline Integrity Engineer or Project Manager - BAP and resolve any comments.

c) Transmit approved Plan to Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Process Review

1 Review the process.

a) Primary responsibility: Process Owner

b) Review the following:

- Processes associated with this area
- Tasks associated with the various processes
- Supporting documentation requirements for the tasks associated with the processes
- Timelines associated with the various processes
- Roles associated with the various processes

c) Enter review results in ICAM

2 Resolve issues.

a) Primary responsibility: Process Owner

b) Resolve issues and discrepancies arising from the process review (Step 1) in accordance with the Process Outline for Management of Change.

-- End of Process C --

INTRODUCTION

This process outline describes the steps necessary for developing the budget and schedule for annual assessments. It also describes the steps necessary for planning and executing the assessments.

This outline describes four processes:

- Process A - Schedule and Budget Development
- Process B - Planning the assessments
- Process C - Executing the assessments
- Process D - Process Review

FREQUENCY OF USE

This process is implemented annually, or as directed by the Director, Pipeline Integrity or Manager, Pipeline Integrity. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

Step **Action and Discussion**

Process A - Schedule and Budget Development

1 Identify pipeline segments to be assessed in upcoming year.

a) Primary Responsibility: Manager, Pipeline Integrity.

b) From the Long-Term Assessment Plan, prepare a list that identifies each pipeline segment to be assessed in the upcoming year and the type of assessment that will be conducted (pressure test, in-line inspection or direct examination)

c) The list will include pipeline segments with Baseline HCAs and newly identified HCAs scheduled for initial assessment, and pipeline segments with HCAs scheduled for reassessment.

e) Supplement the list with known technical and commercial issues concerning any of the scheduled assessments.

f) Transmit the list to System Controls for review and to the Supervisor, Data Management for recordkeeping.

2 Conduct review meeting.

a) Primary responsibility: Manager, Pipeline Integrity.

b) The review meeting is conducted with System Controls and the purpose is to identify issues associated with the list of scheduled assessments and potential resolutions.

c) Document the issues and decisions from the review meeting and transmit to the Supervisor, Data Management for recordkeeping.

3 Finalize list of scheduled assessments for upcoming year.

a) Primary responsibility: Manager, Pipeline Integrity

b) Finalize the list of assessments scheduled for the upcoming year based on results of the review meeting and follow-on actions.

c) Transmit the assessment schedule list to System Control, to the Pipeline Integrity Engineers responsible for pressure testing and in-line inspection, to the Direct Assessment Manager, and to the Supervisor, Data Management.

4 Develop budget.

a) Primary responsibility: Manager, Pipeline Integrity

b) Using the list of scheduled assessments for the upcoming year, develop the annual O&M and Capital budgets for assessments.

c) The O&M budget should include funds for the following:

- Surveys, runs and digs
- Preventive and mitigative measures
- Follow-up work from assessment results and evaluations

d) The capital budget should include funds for the following:

- Pipeline modifications necessary to conduct assessments
- Pipeline segment replacements
- Pipeline segment replacements as a result of assessments
- Preventive and mitigative measures
- Follow-up work from assessment results and investigations

e) Prepare a proposed written budget for the assessments for the upcoming year and submit to Director, Pipeline Integrity (and Company executive management) for approval.

f) Record the final approved budget.

5 Issue list of scheduled assessments.

a) Primary responsibility: Supervisor, Data Management

b) Transmit the list of scheduled assessment for the upcoming year to the departments responsible for performing the assessments. The list shall identify the type of assessment (pressure test, in-line inspection, and direct assessment) and the affected pipeline segment.

- System Control
- Project Services
- Operations
- Manager, Direct Assessment
- Pipeline Integrity Engineer - ILI

-- End of Process A --

Process B - Planning the assessments

1 Conduct planning meeting.

a) Primary responsibility: Manager, Pipeline Integrity.

b) Conduct planning meeting with Project Services and Operations to schedule the assessments and assign project managers.

- Project Managers for Pressure Tests are provided by Project Services
- In-Line Inspections are a joint effort by Pipeline Integrity and Project Services
- Direct Assessments are managed by Pipeline Integrity

2 Schedule the dates for each assessment.

a) Primary responsibility: Assessment Project Managers

b) Considerations and adjustments to the schedule may be required for:

- Pipeline operating constraints (System Control)
- Pipeline modifications
- Contractor availability
- Equipment availability
- Other ongoing assessments

c) Issue final assessment schedule to Operations, Project Services, System Control, Direct Assessment Manager, and Supervisor, Data Management.

-- End of Process B --

Process C - Executing the Assessments

1 Initiate pre-project work.

a) Primary responsibility: Assessment Project Managers

b) Initiate pre-project work

- Contracts (as required)
- Work Orders
- FWRs
- AFEs
- Pigging questionnaire (for ILIs)

2 Perform assessment.

a) Primary responsibility: Assessment Project Managers

b) Perform the pressure test in accordance with the Process Outline for Pressure Testing for Assessment and Book 2, Construction, Specification 47: “Pipeline Pressure Testing”.

c) Perform in-line inspections in accordance with the Process Outline for In-Line Inspections and Procedure PS-03-01-244: “In-Line Inspection and Analysis”.

d) Perform direct assessments in accordance with the following:

Process Outlines:

- External Corrosion Direct Assessment
- Dry Gas Internal Corrosion Direct Assessment
- Stress Corrosion Cracking Direct Assessment

Procedures:

- PS-03-01-232: “External Corrosion Direct Assessment”
- PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment”
- PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”

-- End of Process C --

Process D - Process Review

1 Review the process.

a) Primary responsibility: Process Owner

b) Review the following:

- Processes associated with this area
- Tasks associated with the various processes
- Supporting documentation requirements for the tasks associated with the processes
- Timelines associated with the various processes
- Roles associated with the various processes

c) Enter review results in ICAM

2 Resolve issues.

a) Primary responsibility: Process Owner

b) Resolve issues and discrepancies arising from the process review (Step 1) in accordance with the Process Outline for Management of Change.

-- End of Process D --

PURPOSE

This process outline defines the steps for conducting an in-line inspection of natural gas transmission pipelines to assess their integrity.

There are two processes described in this outline:
Process A - In-line Inspection
Process B - Process Evaluation and Improvement

FREQUENCY OF USE

This process is implemented for every pipeline segment for which in-line inspection is the identified assessment method. The Manager, Pipeline Integrity assigns the person responsible for process implementation for each pipeline segment. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Process A - In-Line Inspection

Step Action/Discussion

1 **Identify pipe segments that will be assessed using In-Line Inspection and identify the ILI tool that will be used for the assessment.**

a) Primary responsibility: Pipeline Integrity Engineer

b) Refer to the Long Term Assessment Plan to identify the pipe segments identified for ILI.

c) Inline Inspections will be conducted using two ILI tools:
- Caliper tool
- Metal loss/crack detection (MFL/TFI) tool
- Refer to Section 2.1 in PS-03-01-244: “In-Line Inspection and Analysis”.

d) Refer to Assessment Selection Flowchart to provide a technical justification for tool selection.

2 Identify pipeline segments that require cleaning and identify the pipeline segments that require modifications to run the selected ILI tool.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Provide the list identified in Step 1 to Operations and Operations will identify which segments require cleaning pig runs.

c) Pipeline modifications may be necessary to launch, run and retrieve the ILI pigs. Project Services will perform a pipeline review of existing facilities to assist in identifying needed pipeline modifications.

d) Document the modifications needed for each pipeline segment and transmit to Manager of Pipeline Integrity and to the Supervisor, Data Management for recordkeeping.

3 Select vendor.

a) Primary responsibility: Pipeline Integrity ILI Engineer and Purchasing

b) Identify potential vendors that can supply and run the selected ILI tools. (Note: different vendors may be selected for caliper tools and for MFL/TFI tools).

c) Provide budget and pricing data to Project Services for preparation of the AFE. Project Services will prepare an AFE and submit to the Manager, Pipeline Integrity for review.

e) Purchasing issues Purchase Order (PO) to vendors.

4 Perform pre-assessment review and conduct scheduling meeting.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Perform pre-assessment review per Section 2.2 in procedure PS-03-01-244: “In-Line Inspection and Analysis”.

c) Meetings to be held prior to planned ILI tool run.

d) Attendees:
- Project Services
- Operations
- System Control
- Pipeline Integrity

e) Discussion topics:
- Pre-assessment review
- Completion of pipeline modifications necessary for tool run
- Customer and system demand issues
- Pipeline flow restrictions
- Personnel assignments within each department
- Installation of aboveground markers
- Other items as required

f) Prepare written minutes of the meeting and transmit to the Supervisor, Data Management for recordkeeping.

5 Meet with vendor on tool scheduling.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) General discussion:
- ILI plan for each pipeline segment
- Planned pipeline modifications
- Tool selections

c) Document the meeting discussions and transmit to the Supervisor, Data Management for recordkeeping.

6 Prepare and issue Pipeline Pigging Questionnaire.

a) Primary responsibility: Project Services and Pipeline Integrity ILI Engineer

b) Project Services prepares pipeline pigging questionnaire (PS-03-01-246: “Pipeline Pigging Questionnaire”).

c) The Pipeline Integrity ILI Engineer reviews the questionnaire, pipe modifications, and selected tool to determine whether additional pipe modifications are needed. Additional pipe modification requirements are transmitted to Project Services.

d) The Pipeline Integrity ILI Engineer reviews the questionnaire for operating condition limitations (highlights and omissions review) and reports limits to vendor.

e) The Pipeline Integrity ILI Engineer transmits the Pipeline Pigging Questionnaire to vendor for review and to the Supervisor, Data Management for recordkeeping.

f) The Pipeline Integrity ILI Engineer resolves issues identified by the vendor based on questionnaire review.

7 Perform caliper tool run.

a) Pipeline Integrity ILI Engineer and Vendor

b) Conduct a pre-tool run conference call.

- Conference call to be held prior to tool run.
- Attendees:
  - Project Services
  - Operations
  - System Control
  - Vendor

  Pipeline Integrity
- Discussion topics:
  - Timing
  - AGM requirements
  - Personnel
  - Equipment needs
  - Gas flow
  - Logistics
  - Customer notification
  - Completion of cleaning pig run
  - Repair Materials

c) Operations launches and conducts caliper tool run. Refer to Section 2.3 in procedure PS-03-01-244: "In-Line Inspection and Analysis".

d) Operations retrieves tool, inspects for damage, washes tool, and reinspects tool. Operations will document any ILI tool damage.

8 Review caliper tool run data.

a) Primary responsibility: Pipeline Integrity ILI Engineer and ILI Vendor

b) Vendor downloads tool run data and reviews with the Pipeline Integrity ILI Engineer.

c) Determine whether to accept tool run (joint vendor/PIE decision).

- If tool run is accepted, tool run data is valid.
  - Date the caliper tool was retrieved from the pipeline is the valid tool run date and is recorded.
  - Vendor analyzes data and issues preliminary report due not later than 48 hours after tool run date.

- If tool run is not accepted, another caliper tool run is conducted until tool run data is determined to be acceptable.

d) Document the results of the review and transmit to the Supervisor, Data Management for recordkeeping.

9 Conduct metal loss/crack detection (MFL/TFI) tool run.

a) Primary responsibility: Pipeline Integrity ILI Engineer and ILI Vendor

b) Conduct pre-tool run conference call.

- Conference call to be held prior to tool run.
- Attendees:
  - Project Services
  - Operations
  - System Control
  - Vendor
  - Pipeline Integrity

- Discussion topics:
  - Timing
  - AGM requirements
  - Personnel
  - Equipment needs
  - Gas flow
  - Logistics
  - Customer notification
  - Repair Materials

c) Operations launches and conducts MFL/TFI tool run. Refer to Section 2.3 in procedure PS-03-01-244: “In-Line Inspection and Analysis”.

d) Operations retrieves tool, inspects for damage, washes tool, and re-inspects tool. Operations will document any ILI tool damage.

10 Review MFL/TFI tool run data.

a) Primary responsibility: ILI Vendor and Pipeline Integrity ILI Engineer

b) The ILI Vendor downloads tool run data and reviews with the Pipeline Integrity ILI Engineer.

c) Determine whether to accept tool run (joint vendor/PIE decision).

- If tool run is accepted, tool run data is valid.
  - Date the MFL/TFI tool was retrieved from the pipeline is the valid tool run date and is recorded.
  - Vendor analyzes data and issues preliminary report due not later than 14 days after tool run date.

- If tool run is not accepted, another tool run is conducted until tool run data is determined to be acceptable.

d) Document the results of the review and transmit to the Supervisor, Data Management for recordkeeping.

11 Prepare, issue and review final tool run reports.

a) Primary responsibility: ILI Vendor and Pipeline Integrity ILI Engineer

b) Caliper tool vendor prepares final report and transmits to the Pipeline Integrity ILI Engineer 30-90 days after valid tool run date.

- The Pipeline Integrity ILI Engineer reviews the caliper final report for pipeline integrity issues and impacts on MFL/TFI tool run.
- The Pipeline Integrity ILI Engineer transmits caliper final report to MFL/TFI tool vendor for correlation of dents and pipe bend data with MFL/TFI tool run data.

c) MFL/TFI tool vendor prepares final report and transmits to the Pipeline Integrity ILI Engineer 30-90 days after valid tool run date.

- Final report includes integration of caliper and ILI tool run data to identify possible areas of third party damage. Refer to procedure PS-03-01-244: “In-Line Inspection and Analysis”.
- Final report is based on Section 2.5 in procedure PS-03-01-244: “In-Line Inspection and Analysis”.
- The Pipeline Integrity ILI Engineer analyzes the final report and integrates data with Company pipe data and alignment sheets for comparison to identify discrepancies.
- The Pipeline Integrity ILI Engineer resolves discrepancies with vendor, region teams, and Project Services.
- The Pipeline Integrity ILI Engineer accepts final report and notifies vendor.

d) Identify and record the dates of the valid tool runs and transmit, together with the vendor final tool run reports, to the Supervisor, Data Management for recordkeeping.

12 Conduct tool run data review.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) The post-assessment review must be completed.

c) Verify the data is collected in accordance with procedure PS-03-01-244: “In-Line Inspection and Analysis”. Evaluate the final report in accordance with the same procedure.

d) Using the MFL/TFI final report data, integrate with foreign line crossing data to review for evidence of third party damage.

e) Perform B31G remaining strength calculations for all indications identified in final reports.

f) Response time (maximum time allowed to perform repair) is determined by using B31.8S Figure 4. (See Procedure PS- 03-01-252 "Schedule of Repair Requirements")

- Immediate response classifications are based on specific lists of types of defects.

- Scheduled and Monitored classifications are based on the maximum allowed response time. Scheduled classifications are 0-84 months (7 years) and Monitored classifications are any over 84 months.

g) Document the indication severity classifications, remaining strength calculations and response times and transmit to the Supervisor, Data Management for recordkeeping.

h) If internal or external corrosion is identified written notification will be supplied to External Corrosion Program Manger or Project Manager Internal Corrosion Program.

13 Prepare dig list.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) From step 12, prepare a dig list for indications classified as "Immediate" and "Scheduled". Use procedure PS-03-01-244: "In-Line Inspection and Analysis" as a guide.

c) The minimum number of digs required is two. If there is only one "Immediate" or only one "Scheduled" indication, then the next most severe indication is selected as the second dig. If there are no "Immediate" or "Scheduled" indications, then the two most severe "Monitored" indications are selected for examination.

d) PI conducts conference call to discuss tool run findings and indication classifications.

- Attendees:
  - Operations
  - System Control
  - Project Services
  - Pipeline Integrity

- Discussion topics:
  - Dig list
  - Date of discovery will be documented
  - Pressure reduction requirements for "Immediate" indications will be documented

e) Transmit the dig list to Operations and Project Services for action and to the Supervisor, Data Management for recordkeeping.

14 Schedule and monitor digs.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Pipeline Integrity ILI Engineer develops a multi-year schedule (up to 7 years' duration) for all digs. Maximum allowable response time cannot be exceeded.

c) Provide resolutions to field crews concerning issues with digs such as:
- Problems with locating reference girth welds
- Problems locating the indications
- Anomaly size discrepancies
- Special conditions

d) Data for "Monitored" conditions is recorded in the Pipeline Integrity database for comparison in future ILI tool runs.

15 Complete post-assessment.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) The Supervisor, Data Management collects dig and repair data.

c) Develops a unity plot. Provide unity plot and data feedback to ILI vendor.

d) Complete the ILI Post-Assessment Form. The information on the form is periodically updated and re-evaluated at least annually as digs are completed.

e) Compile feedback data for:
- Evidence of defects in non-HCA areas
- Third party damage
- Active corrosion
- Potential defects in pipe in other covered and non-covered segments where the pipe has similar characteristics.

f) Input Post-Assessment Form and feedback information to Continual Evaluation and Assessment process.

g) Perform a comparison review of tool run data versus the pipe database to identify discrepancies. Discrepancies are reported to the Supervisor, Data Management. The Supervisor, Data Management resolves discrepancies with Project Services and Region Teams.

16 Determine reassessment interval.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Determine reassessment interval.
   - o Determined by using Figure 4 and Table 3 in B31.8S

c) Document reassessment interval and transmit to the Pipeline Integrity Engineer or Project Manager responsible for baseline assessment planning for input into the long-term assessment plan.

d) Transmit completed Post Assessment to the Supervisor, Data Management for recordkeeping.

-- End of Process A --

Process B - Process Evaluation and Improvement

<u>Step</u> **<u>Action and Discussion</u>**

1 Review and evaluate the in-line inspection process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review the overall process.
- Are additional tasks or supporting procedures needed?

c) Describe the additional tasks or supporting procedures.

2 Review and evaluate the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review each task for completeness.
- Are additional details needed to properly describe the task?

c) Describe the additional details needed.

3 Review and evaluate the referenced procedures that support the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review the procedures for completeness.
- Are procedures sufficient to support the tasks?

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review the supporting documentation.
- Is additional supporting documentation needed.?

c) Describe the additional supporting documentation needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review the timeliness for performing the tasks.
- Were on-time completion percentages acceptable?

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Review the assigned primary responsibilities for each task.
- Are assigned responsibilities correct?

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: Pipeline Integrity ILI Engineer

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
- Identify revised tasks and new tasks.
- Identify revised supporting procedures or new supporting procedures.
- Identify revised forms or new forms.
- Identify new supporting documentation and supporting documentation format changes.
- Identify changes to schedule for performing the process.
- Identify organizational changes.

c) Document the review and evaluation results and transmit to the Manager of Pipeline Integrity for review and approval.

d) Transmit the approved changes to the Management of Change process and also the Continual Evaluation and Assessment Process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process B --

INTRODUCTION

This process outline describes the steps for conducting dry gas internal corrosion direct assessments (DG-ICDA).

There are five processes described in this outline:
Process A - Pre-Assessment
Process B - Indirect Inspection
Process C - Direct Examination
Process D - Post Assessment
Process E - Evaluation and Improvement

FREQUENCY OF USE

This process is implemented for every pipeline segment for which internal corrosion direct assessment is the identified assessment method. The Manager, Direct Assessment assigns the person responsible for process implementation for each pipeline segment. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Process A - Pre-Assessment

<u>**Step**</u> <u>**Action and Discussion**</u>

1 For the pipeline segment being considered for application of DG-ICDA, determine whether this will be a first-time application.

a) Primary responsibility: O&M Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Determine whether DG-ICDA has been applied previously to the pipeline segment.
- Identify date of previous assessment.

c) If this is a first-time application of DG-ICDA, more restrictive criteria is required. Define the more restrictive criteria to be utilized for the following:
- Pre-Assessment
- Indirect Inspection
- Direct Examination

d) Document the criteria and transmit to the Supervisor, Data Management for recordkeeping.

2 Perform system analysis.

a) Primary responsibility: O&M Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Identify candidate pipeline for potential application of DG-ICDA.
- Review annual and long-term assessment plans.
- Identify pipeline segment with high consequence area (HCA).

c) Review pipeline transmission system maps.
- Refer to Sections 3.3.1 through 3.3.4 in Procedure PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment”.
- Identify all pipelines that carry the same gas as the candidate pipe, including pipe adjoining the candidate pipe.
- Determine whether the candidate pipe is directly connected to gas gathering pipelines (potential presence of high moisture content in the gas stream).
- Determine whether the gas is scrubbed or dehydrated before entering the pipeline system (reduced likelihood of moisture in the gas stream).

d) Collect data.
- The following data is required for system analysis (refer to Section 3.3.5 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment"):
  - Previous in-line inspections
  - Previous DG-ICDA assessments
  - Leak history
  - Previous cleaning pig runs
  - Corrosion inhibitor application information
  - Installed corrosion monitoring device information
  - Gas quality analysis reports
  - Fluid sample analyses
- Use the DG-ICDA Data Element Form (electronic spreadsheet) identified in Procedure PS-03-01-239: "Dry Gas - ICDA Data Element Form" to record the data collected.

e) Develop system analysis document.
- Identify candidate pipe.
- Describe upstream operations and inspection activities based on pipe system configuration and data collected.

f) Transmit system analysis document to Supervisor, Data Management for recordkeeping.

g) Review of data collected may indicate historical or active internal corrosion is present. Notify the Internal Corrosion Project Manager that data can be reviewed and follow-up action taken if necessary (refer to Section 3.3.7 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment").

3 Perform feasibility assessment.

a) Primary responsibility: O&M Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Perform feasibility assessment of application of DG-ICDA to the candidate pipeline.
   - Refer to Sections 3.3.8 and 3.3.9 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".
   - Analyze data collected in Process A, Step 1.
   - Use Table 2: "Feasibility Filter Information Worksheet" in Procedure PS-03-01-238 to analyze the data.
   - Use Figure 2: "DG-ICDA Feasibility Filter" in Procedure PS-03-01-238 to guide the feasibility assessment.

c) Document results of feasibility assessment of application of DG-ICDA to the candidate pipeline.

d) Transmit feasibility assessment documentation, including worksheet, to Supervisor, Data Management for recordkeeping. If application of DG-ICDA is not feasible for the candidate pipe, notify Pipeline Integrity Engineer or Project Manager responsible for baseline assessment planning.

4 Collect additional data.

a) Primary responsibility: O&M Specialist, DA Specialist or Direct Assessment Manager

b) If DG-ICDA is feasible for the candidate pipe, collect the following additional data (refer to Section 3.4 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment"):
   - Dew point (water vapor)
   - Gas flow rate
   - Gas temperature
   - Gas pressure
   - Pipe wall thickness
   - Pipe diameter

c) Use the DG-ICDA Data Element Form (electronic spreadsheet) identified in Procedure PS-03-01-239: "Dry Gas - ICDA Data Element Form" to record the data collected.

d) Refer to Section 3.5 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment" for the handling of missing data and impact on application of DG-ICDA.

e) Document the data collected, identify missing data, and identify data assumptions including basis for assumptions. Transmit to Supervisor, Data Management for recordkeeping.

5 Identify DG-ICDA regions.

a) Primary responsibility: O&M Specialist, DA Specialist or Direct Assessment Manager

b) Identify DG-ICDA regions.
- Refer to Section 3.6 and all subsections in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

c) Based on the additional data collected in Process A Step 3, identify the DG-ICDA regions that have missing data. DG-ICDA cannot proceed for these regions until the data is obtained.

d) Document the DG-ICDA regions. Document the DG-ICDA regions that are missing data. Transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process A --

Process B - Indirect Inspection

Step Action and Discussion

1 Perform flow model calculations.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Perform flow model calculations.
- Refer to Section 4.4 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".
- Use spreadsheet to calculate (see Figure 3: "Critical Inclination Angle Calculator" in Procedure PS-03-01-238).
- Determine critical inclination angles.

c) Compile flow model calculations and transmit to Supervisor, Data Management for recordkeeping.

2 Schedule land survey for pipeline elevation profile.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Prepare work package.
- Identify candidate pipeline.
- Identify DG-ICDA regions.

c) Transmit work package to Field Team for action and to Supervisor, Data Management for recordkeeping.

3 Perform land survey.

a) Primary responsibility: Field Team (O&M/Outsource Qualified Personnel)

b) Perform land survey to collect pipeline elevation profile data.
- Conduct the land survey in accordance with the work package and Appendix A of Procedure PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment”.
- Calibrate the survey equipment and perform the survey.
- Verify accurate data is being recorded by the survey equipment.
- Record survey data.

c) Collect results of the survey.
- Download survey data into Excel spreadsheets.
- Upload spreadsheets to Company computer system.

4 Perform quality check of land survey data collected.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Evaluate the quality of the data collected during the tool run.
- Was data collected for the specified length of the DG-ICDA region?
- Are the results reasonable?

c) Determine whether the survey needs to be performed again.

d) Evaluate quality of data from re-survey, if performed.

e) Document the results of the quality check and send to the Supervisor, Data Management for recordkeeping.

5 Perform indirect inspection resurvey if needed.

a) Primary responsibility: Field Team (O&M/Outsource Qualified Personnel)

b) Perform land survey again in accordance with Process B Step 3 if so directed based on results of Step 4.

6 Develop DG-ICDA alignment sheet.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Calculate pipeline elevation profile.
- Refer to Sections 4.5.2 through 4.5.3 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".
- Use the "Proactive" computer software to prepare the DG-ICDA Water Holdup/Dig Site Selection Plot (see Section 4.5.3 and Figure 4 in Procedure PS-03-01-238).

7 Select dig sites for direct examination.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Use DG-ICDA Alignment Sheet developed in Process B Step 7

c) Select and record dig sites for direct examination in accordance with Sections 4.6 and 4.7 of Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

d) Transmit dig site selection list and DG-ICDA Alignment Sheets developed in Step 6 to Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Direct Examination

<u>Step</u> **<u>Action and Discussion</u>**

1 Prepare direct examination work package.

a) Primary responsibility: O&M Specialist or DA Specialist

b) The work package identifies the minimum two required dig sites and their locations and prioritizes them for direct examination based on comparisons of flow modeling results and the pipeline elevation profile. The work package also identifies the method of nondestructive examination to be used.

c) Transmit the work package to the Field Team for action and to the Supervisor, Data Management for recordkeeping.

2 Perform direct examinations.

a) Primary responsibility: Direct Examination Supervisor (O&M Qualified Personnel and NDT Qualified Personnel)

b) Excavate the pipe in accordance with Book 2, Construction, Specification 55: “Excavations”, Book 1, O&M, Procedure 114: “Hazardous Atmospheres in Excavations” and appropriate safety procedures in Book 6, Safety.

c) Prepare the pipe surface for nondestructive examination.

d) Collect and record data using the Dig Data Sheet in Procedure PS-03-01-242: “Dig Data Sheet”.
- Refer to Section 5.7.3 in Procedure PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment”.
- Measure the wall thickness.
- Determine wall loss if any.
- Determine extent of wall loss, if any (measure axial length and width of wall loss area).

e) Calculate remaining strength of the pipe.
- Refer to procedure PS-03-02-200: “Evaluation of Remaining Strength of Corroded Pipe”.
- Perform calculation for wall loss areas.
- Record the calculation using Dig Data Sheet.

f) Compile all data collected and transmit to the Supervisor, Data Management for recordkeeping. Notify the Pipeline Integrity Engineer that the direct examination data is available for review.

3 Evaluate direct examination data.

a) Primary responsibility: Direct Examination Supervisor or Pipeline Integrity Engineer

b) If data collected during direct examination indicates presence of internal corrosion, perform the following:
- Refer to Procedure PS-03-01-250: “Pipeline Evaluation & Remediation”.
- Classify severity of indications (Section 2.3 in PS-03-01-250).
- Identify Date of Discovery (Section 2.2 in PS-03-01-250).
- Determine remediation requirements (refer to Procedure PS-03-01-252: “Schedule of Repair Requirements”.

c) If there is no evidence of internal corrosion, document the conclusion.

d) Notify Internal Corrosion Project Manager that results of the direct examination are available for review and follow-up action.

e) Compile all data and transmit to Supervisor, Data Management for recordkeeping.

4 Review direct examination data for follow-up actions.

a) Primary responsibility: Internal Corrosion Project Manager

b) Review results of all direct examinations.
- Refer to Process C, Steps 2 and 3.

c) Develop and implement follow-up actions.
- Refer to Section 5.10 in Procedure PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment”.

5 Determine additional direct examination dig sites.

NOTE: This step is performed only if internal corrosion was detected at either of the two initial direct examination dig sites.

a) Primary responsibility: O&M Specialist or DA Specialist

b) Determine additional direct examination dig sites in accordance with Sections 5.5 and 5.6 of Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

c) Prepare work package for additional direct examinations.

d) Transmit the work package to the Field Team for action and to the Supervisor, Data Management for recordkeeping.

6 Perform additional direct examinations.

NOTE: This step is performed only if internal corrosion was detected at either of the two initial direct examination dig sites.

a) Primary responsibility: Direct Examination Supervisor (O&M Qualified Personnel and NDT Qualified Personnel)

b) Perform additional direct examinations following Process C Step 2.

7 Evaluate additional direct examination data.

NOTE: This step is performed only if internal corrosion was detected at either of the two initial direct examination dig sites.

a) Primary responsibility: Direct Examination Supervisor or Pipeline Integrity Engineer

b) Evaluate the additional direct examination data following Process C Step 3.

8 Perform pipe repairs in accordance with remediation schedule.

NOTE: This step is performed only if internal corrosion was detected at either of the two initial direct examination dig sites.

a) Primary responsibility: Project Services

b) Perform pipe repair in accordance with Book 1, O&M, Procedure 226: Pipeline Repairs - Existing In-Service Pipelines" and document repair using Form 1: Documentation of Defect and Repair".

9 Reevaluate feasibility of using DG-ICDA.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Re-evaluate the feasibility of using DG-ICDA in the DG-ICDA region.
- Refer to Section 5.6.4 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".
- Based on results of direct examinations.
- Based on extensiveness of internal corrosion, if present.
- Based on comparison of pre-assessment and indirect inspection expectations versus direct examination results.

c) Document the feasibility evaluation and transmit to:
- Direct Assessment Management for review.
- Pipeline Integrity Engineer or Project Manager responsible for Baseline Assessment Planning for action (selection of alternate assessment method).
- Supervisor, Data Management for recordkeeping.

-- End of Process C --

Process D - Post Assessment

<u>Step</u> <u>Action and Discussion</u>

1 Assess the effectiveness of DG-ICDA.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Assess the effectiveness of DG-ICDA.
- Refer to Section 6.2 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".
- Correlation of location and extent of water holdup/internal corrosion found during direct examination versus expected locations predicted in indirect inspection.
- Use of mathematical approach.
- Implications of widespread internal corrosion and internal corrosion found at the top of the pipe.

c) Document the assessment results and transmit to the Supervisor, Data Management for recordkeeping.

2 Determine reassessment interval.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Calculate the estimated internal corrosion growth rate in accordance with Section 6.3 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

c) Calculate remaining life in accordance with Section 6.4 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

d) Determine reassessment interval based on estimated corrosion growth rate and remaining life calculations.
- Refer to Section 2.2 in Procedure PS-03-01-260: "Reassessment Guidelines".

e) Determine whether the internal corrosion threat is stabilized.
- Refer to Section 6.5 in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment" and consider the following:
  - – Evidence of historical internal corrosion.
  - – Evidence of active internal corrosion.
  - – No evidence of internal corrosion.
  - – Internal corrosion monitoring equipment in place.

f) Document the estimated corrosion growth rate and remaining life calculations, the reassessment interval and threat stabilization evaluation and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process D --

Process E - Evaluation and Improvement

Step **Action and Discussion**

1 **Review and evaluate the dry gas internal corrosion direct assessment process.**

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the overall process.
- All tasks necessary to implement the process are sufficiently identified.
- Additional tasks or supporting procedures are needed.

c) Describe the additional tasks or supporting procedures.

2 **Review and evaluate the tasks associated with the process.**

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review each task for completeness.
- Description of each task is sufficient.
- Additional details are needed to properly describe the task.
- Are new procedures needed to provide the details?

c) Describe the additional details needed.

3 **Review and evaluate the referenced procedures that support the tasks associated with the process.**

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the procedures for completeness.
- Procedures are sufficient to support the tasks.
- Additional steps need to be added to the procedures.
- Additional procedures are needed.

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager
b) Review the supporting documentation.
- Supporting documentation is sufficient.
- Additional supporting documentation is needed.
- Are additional forms needed?

c) Describe the additional supporting documentation needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager
b) Review the timeliness for performing the tasks.
- On-time completion percentages were acceptable.
- On-time completion percentages were not acceptable.

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the assigned primary responsibilities for each task.
- Assigned responsibilities are correct.
- Changes in assigned responsibilities are needed.

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
- Identify revised tasks and new tasks.
- Identify revised supporting procedures or new supporting procedures.
- Identify revised forms or new forms.
- Identify new supporting documentation and supporting documentation format changes.
- Identify changes to schedule for performing the process.
- Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process E --

INTRODUCTION

This process outline describes the steps for conducting stress corrosion cracking direct assessments (SCCDA).

There are five processes described in this outline:
Process A - Pre-Assessment
Process B - Indirect Inspection
Process C - Direct Examination
Process D - Post Assessment
Process E - Evaluation and Improvement

This process is limited to assessment of high pH SCC. Use of this procedure for assessment of near-neutral pH SCC requires notification to PHMSA for use of "other technology".

FREQUENCY OF USE

This process is implemented for every pipeline segment for which stress corrosion cracking direct assessment is the identified assessment method. The Manager, Direct Assessment assigns the person responsible for process implementation for each pipeline segment. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Process A - Pre-Assessment

Step **Action and Discussion**

1 Identify SCCDA-susceptible pipeline segment.

a) Primary responsibility: Pipeline Integrity Engineer or Direct Assessment Manager

b) Identify candidate pipeline for potential application of SCCDA.
   - Review annual and long-term assessment plans.

c) Use of this process for assessing near-neutral pH SCC requires notification to PHMSA for use of "other technology".
   - Refer to Process Outline: "Communication", and Procedure PS-03-01-264: "IMP Communication Plan".

2 Gather data.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Gather data for the susceptible pipeline segments in accordance with Section 3.4 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".
   - Refer to Table 1: "Factors to Consider in Prioritization of Susceptible Segments and in Site Selection" in Section 3.4.

c) The data elements to be collected are grouped into five categories:
   - Pipe related
   - Construction related
   - Soils/Environmental
   - Corrosion control
   - Operational data

d) The Typical sources for the data are listed. Other data sources may need to be used for data not available in the listed sources.
   - Maximo
   - PODS
   - TOPS (Archived Database)
   - Subject Matter Experts
   - Alignment Sheets

e) Resolve data conflicts.

   NOTE: In the event data classified as "required" is missing, SCCDA cannot proceed for those SCCDA regions until appropriate data can be obtained.

f) Determine whether additional information using indirect inspection techniques is needed.

g) Record data collected and whether additional information is needed using indirect inspection. Transmit to the Supervisor, Data Management for recordkeeping.

3 Select and prioritize dig sites.

NOTE: This step is delayed if additional information from indirect inspections is needed to accurately select dig sites.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Select and prioritize dig sites in accordance with Section 3.5 in Procedure PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”.

c) Dig site selection and prioritization may also be based on defect information obtained from In-Line Inspection surveys.

d) Where indirect inspection (Process B) is performed, use indication severity classification to assist in prioritizing dig sites.

e) Record dig site selections and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process A --

Process B - Indirect Inspection

NOTE: The objectives of the indirect inspection process are to conduct aboveground or other types of measurements to supplement the data from the pre-assessment process if additional information is needed and then to use the data to prioritize susceptible pipeline segments and select the specific sites for direct examination.

<u>Step</u> <u>Action and Discussion</u>

1 Select Indirect Inspection Tool(s).

a) Primary responsibility: DA Specialist or O&M Specialist

b) For the SCCDA regions select the tool to be used for indirect inspection. One or more tools may be utilized.
- See Section 6.0 in Procedure PS-03-01-232: "External Corrosion Direct Assessment" for guidance in tool selection.
- Refer to Table 2: "ECDA Tool Selection Matrix" in Section 6.0 for further guidance.

c) Document the tools selected and reasons for selection. Transmit to the Supervisor, Data Management for recordkeeping.

2 Develop indirect inspection instructions for Field Team.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Develop indirect inspection instructions (pre-assessment) for conducting the survey.
- Identify the schedule for the survey.
- Identify start and end points.
- Identify tools
- Identify specific requirements for conducting the survey if this is a first-time application of the SCCDA process to the pipeline segment.
- Identify minimum data requirements.

c) Transmit the instructions (pre-assessment) to the Field Team and transmit a copy to the Supervisor, Data Management for recordkeeping.

3 Perform indirect inspection.

a) Primary responsibility: DA Field Supervisor or DA Technician

b) Conduct the indirect inspection in accordance with the instructions.
- Clearly mark the boundaries of the SCCDA region (start and end points)
- Calibrate the survey tools and perform the surveys.
- Verify accurate data is being recorded by the survey tools.
- Record aboveground locations using sub-meter accuracy GPS location meters.

c) Collect results of the survey tools and download to company computer system ("ProActive").

4 Perform quality check of data collected during tool run.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Evaluate the quality of the data collected during the surveys.
- Was data collected for the entire length of the SCCDA region?
- Are the results reasonable?

c) Determine whether the surveys need to be performed again or new tools selected.

d) Evaluate quality of data from new surveys or survey reruns.

e) Document the results of the quality check and send to the Supervisor, Data Management for recordkeeping.

5 Perform indirect inspection resurvey if needed.

a) Primary responsibility: DA Field Supervisor or DA Technician

b) Perform surveys again using same or different tools in accordance with Process B Step 3 if so directed based on results of Process B Step 4.

6 Spatially align data from the indirect inspection.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Spatially align the data from the surveys.
- Refer to Sections 8.6.1 and 8.6.2 in Procedure PS-03-01-232: “External Corrosion Direct Assessment”.
- Use the “Proactive” computer software to develop the Direct Assessment Alignment Sheet.

c) Document the data alignment. Provide discussion of any spatial alignment errors. Transmit the alignment document to the Supervisor, Data Management for recordkeeping.

7 Classify severity of indications.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Classify severity of indications.
- Use Table 3: "Severity Classification Table" in Section 8.6.3 of Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Consider known survey tool sensitivities.
- Identify and resolve inconsistencies in data between the survey tools.
- Classify indications both by individual tool and by combined tool.
- Use more restrictive classification criteria for first-time application of ECDA.

c) If data inconsistencies cannot be explained, consider rerunning the indirect inspection (repeat Steps 3, 4, and 6).

d) Document data inconsistencies and resolution, the severity classification, the criteria used, and reasoning for classification and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Direct Examination

Step Action and Discussion

1 Develop schedule for direct examination of indications.

a) Primary responsibility: Direct Examination Supervisor or O&M Specialist

b) Develop schedule for direct examination.

c) Transmit schedule to Field Team for action and to Supervisor, Data Management for recordkeeping.

2 Perform direct examinations.

a) Primary responsibility: Direct Examination Supervisor (O&M Qualified Personnel and NDT Qualified Personnel)

b) Perform direct examination in accordance with the following process outline and procedures:
- Process Outline: "Pipe Inspection, Defect Evaluation, and Pipe Repair".
- Book 1, O&M, Procedure 235: "Exposed Pipe Examination".
- Procedure PS-03-01-242: "Dig Data Sheet".

c) Transmit all data generated during direct examination to Supervisor, Data Management for recordkeeping.

3 Evaluate crack clusters.

a) Primary responsibility: Direct Examination Supervisor or Direct Examination Technologist

b) Evaluate crack clusters in accordance with Section 5.9.4 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".

c) Determine type of cracking in accordance with Section 5.10 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".

d) Determine severity of cracking in accordance with Section 5.11 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".

e) Document evaluation and transmit to the Supervisor, Data Management for recordkeeping.

4 Determine mitigation requirements.

a) Primary responsibility: Pipeline Integrity Engineer or Direct Examination Supervisor

b) Determine whether discrete SCC mitigation is required.
- Refer to Section 7.2.1 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".
- Repair or removal of the affected pipe length.
- Pressure testing the pipeline segment.
- Engineering critical assessment.

c) Determine whether general mitigation is required.
- Refer to Section 7.2.2 in Procedure PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”.
- Pressure testing of affected pipeline segments.
- In-Line Inspection when appropriate tools are available
- Extensive pipe replacement
- Recoating

d) Document mitigation evaluation and report results to Field Team for action. Transmit evaluation to the Supervisor, Data Management for recordkeeping.

5 Perform pipe repair or replacement.

a) Primary responsibility: Field Team

b) If pipe repair or replacement is the selected SCC mitigation method, perform repair/replacement in accordance with Book 1, O&M, Procedure 226: “Pipeline Repairs - Existing In-Service Pipelines”

c) Document results of repair or replacement using the following:
- Maximo
- Form 1: “Documentation of Defect and Repair”
- Dig Data Sheet

d) Transmit Dig Data Sheet to the Supervisor, Data Management for recordkeeping.

-- End of Process C --

Process D - Post Assessment

Step Action and Discussion

1 Schedule selected SCC mitigation method for implementation.

a) Primary responsibility: Pipeline Integrity Engineer or Direct Assessment Manager

b) This step does not include pipe repair/replacement or recoating which was handled in Process C Step 5.

c) Schedule pressure test, if selected.
- Book 2, Construction, Procedure 47: “Pipeline Pressure Testing”.
- Notify Pipeline Integrity Engineer responsible for pressure testing.

d) Schedule In-Line Inspection, if selected.
- Procedure PS-03-01-244: “In-Line Inspection & Analysis”.
- Notify Pipeline Integrity Engineer responsible for ILI.

e) Perform engineering critical assessment, if selected.
- Section 7.5 in Procedure PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”.

f) Document the schedule, notifications or critical assessment and transmit to the Supervisor, Data Management for recordkeeping.

2 Determine reassessment interval.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Determine reassessment interval based on estimated crack cluster propagation and remaining life calculations.
- Refer to Section 7.6 in Procedure PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”.
- Refer to Section 2.2 in Procedure PS-03-01-260: “Reassessment Guidelines”.

c) Document the estimated crack cluster propagation rate and remaining life calculations, and the reassessment interval and transmit to the Supervisor, Data Management for recordkeeping.

3 Assess the effectiveness of SCCDA.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Assess the effectiveness of SCCDA.
- Refer to Section 7.7 in Procedure PS-03-01-240: "Stress Corrosion Cracking Direct Assessment".
- Select method or methods.
- Select and monitor performance measures.

c) Document the effectiveness assessment and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process D --

Process E - Evaluation and Improvement

<u>Step</u> <u>Action and Discussion</u>

1 Review and evaluate the stress corrosion cracking direct assessment process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the overall process.
- All tasks necessary to implement the process are sufficiently identified.
- Additional tasks or supporting procedures are needed.

c) Describe the additional tasks or supporting procedures.

2 Review and evaluate the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review each task for completeness.
- Description of each task is sufficient.
- Additional details are needed to properly describe the task.
- Are new procedures needed to provide the details?

c) Describe the additional details needed.

3 Review and evaluate the referenced procedures that support the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the procedures for completeness.
- Procedures are sufficient to support the tasks.
- Additional steps need to be added to the procedures.
- Additional procedures are needed.

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager
b) Review the supporting documentation.
- Supporting documentation is sufficient.
- Additional supporting documentation is needed.
- Are additional forms needed?

c) Describe the additional supporting documentation needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the timeliness for performing the tasks.
- On-time completion percentages were acceptable.
- On-time completion percentages were not acceptable.

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the assigned primary responsibilities for each task.
- Assigned responsibilities are correct.
- Changes in assigned responsibilities are needed.

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
- Identify revised tasks and new tasks.
- Identify revised supporting procedures or new supporting procedures.
- Identify revised forms or new forms.
- Identify new supporting documentation and supporting documentation format changes.
- Identify changes to schedule for performing the process.
- Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process E --

INTRODUCTION

This process outline describes the steps for conducting a pressure test to assess the integrity of a pipeline segment.

FREQUENCY OF USE

This process is implemented for every pipeline segment for which pressure testing is the identified assessment method. The Director, Pipeline Integrity or Manager, Pipeline Integrity assigns the person responsible for process implementation for each pipeline segment. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Step Action and Discussion

1 Identify and prioritize pipeline segment for pressure testing.

a) Primary responsibility: Pipeline Integrity Engineer
- Review annual and long-term assessment plans.
- Receive notification from Stress Corrosion Cracking Direct Assessment process.

b) Determine test timeline.
- Based on annual and long-term assessment plans.
- Based on severity classification of indications for SCC mitigation in SCCDA process.
- Based on pipeline operating constraints (preliminary).

c) Document the pipeline identification and test schedule requirements.

2 Determine test parameters.

a) Primary responsibility: Pipeline Integrity Engineer

b) Determine pipe characteristics.
- Data source: PODS
- Pipe diameter
- Pipe wall thickness
- Pipe grade
- MAOP
- %SMYS

c) Determine testing medium. Refer to Table 47.2 in Book 2, Construction, Specification 47: "Pipeline Pressure Testing" Table 47.2.
- Hydrostatic (water)
- Pneumatic (air, natural gas, or inert gas)

d) Determine test pressure and time at pressure. Refer to Table 47.2 in Book 2, Construction, Specification 47: "Pipeline Pressure Testing".
- Maximum test pressure
- Minimum test pressure
- Test duration

e) Document the pipe characteristics, test medium, test pressures and test duration.

3 Prepare work package.

a) Primary responsibility: Pipeline Integrity Engineer

b) Prepare work package. The work package includes:
- Pipe segment identification and location
- Pipe characteristics
- Testing schedule
- Test medium
- Test pressures
- Test duration

c) Transmit the work package to Engineering & Compliance - Project Services for action and to the Supervisor, Data Management for recordkeeping.

4 Select vendor.

a) Primary responsibility: Engineering & Compliance - Project Services

b) Identify potential vendors.

c) Obtain budget and pricing data from Pipeline Integrity for preparation of the AFE.

d) Manager, Pipeline Integrity approves AFE for processing.

e) Purchasing issues RFP to vendors. RFP includes:
- Information from work package.
- Book 2, Construction, Specification 47: “Pipeline Pressure Testing”.

f) Select vendor and notify Purchasing to issue Purchase Order.

5 Conduct scheduling meeting.

a) Primary responsibility: Engineering & Compliance - Project Services

b) Attendees:
- Project Services
- Operations
- System Control
- Pipeline Integrity

c) Discussion topics:
- Pipeline modifications necessary for pressure test.
- Customer and system demand issues.
- Pipeline flow restrictions.
- Personnel assignments within each department.

6 Conduct pressure test.

a) Primary responsibility: Contractor

b) Conduct pressure test in accordance with Book 2, Construction, Specification 47: “Pipeline Pressure Testing”.
- Cleaning pig run.
- Pipe filling with test medium.
- Test at required pressure and duration.
- Post-test pipeline cleanup.

c) Repair or replace test equipment that fails during the test and resume testing until the required cumulative test hours are reached.

d) If a pipe failure occurs during pressure test, stop test and notify Engineering & Compliance - Project Services. If there are no pipe failures during the pressure test, complete this step (items a through e) and go to Step 10 in this process.

e) Prepare test results report in accordance with Section I in Specification 47 and transmit to Engineering & Compliance - Project Services.

7 Handling of pipe failures during pressure test.

NOTE: This step occurs only if there is a pipe failure during the pressure test.

a) Primary responsibility: Engineering & Compliance - Project Services

b) Contractor notifies Engineering & Compliance - Project Services of pipe failure during pressure test.

c) Perform root cause analysis of pipe failure.
- Refer to Section H in Book 2, Construction, Specification 47: “Pipeline Pressure Testing”.
- Consult with Pipeline Integrity.

d) Notify Field Team of pipe failure.

8 Repair or replace the pipe.

NOTE: This step occurs only if there is a pipe failure during the pressure test.

a) Primary responsibility: Field Team

b) Evaluate and repair the pipe in accordance with the following process outline and procedures:
- Book 1, O&M, Procedure 235: "Exposed Pipe Examination".
- Procedure PS-03-01-242: "Dig Data Sheet".

c) Notify Engineering & Compliance - Project Services when repair/replacement is complete.

9 Restart pressure test.

NOTE: This step occurs only if there is a pipe failure during the pressure test.

a) Primary responsibility: Engineering & Compliance - Project Services

b) Notify Contractor to retest the pipe in accordance with Step 6 of this process.

10 Post-test actions.

a) Primary responsibility - Engineering & Compliance - Project Services

b) Receive test results report from Contractor.
- Review for accuracy and completeness.
- Enter test results into Maximo.

c) Notify Pipeline Integrity Engineer that test is complete and provide copy of test results report to the Supervisor, Data Management for IMP recordkeeping.

11 Determine reassessment interval.

a) Primary responsibility: Pipeline Integrity Engineer

b) Determine reassessment interval.
- Refer to Section 2.2 in PS-03-01-260: "Reassessment Guidelines".

c) For pressure tests conducted as part of SCC mitigation, transmit pressure test results report to the Pipeline Integrity Engineer or Project Manager responsible for SCCDA for determination of reassessment interval.

d) Document reassessment interval and transmit to the Pipeline Integrity Engineer or Project Manager responsible for baseline assessment planning for input to the annual and long-term assessment plans.

e) Transmit reassessment interval documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process --

INTRODUCTION

This process outline describes the steps for conducting external corrosion direct assessments.

There are five processes described in this outline
Process A - Pre-Assessment
Process B - Indirect Inspection
Process C - Direct Examination
Process D - Post Assessment
Process E - Evaluation and Improvement

FREQUENCY OF USE

This process is implemented for every pipeline segment for which external corrosion direct assessment is the identified assessment method. The Manager, Direct Assessment assigns the person responsible for process implementation for each pipeline segment. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Process A - Pre-Assessment

<u>**Step**</u> <u>**Action and Discussion**</u>

1 For the pipeline segment being considered for application of ECDA, determine whether this will be a first-time application.

a) Primary responsibility: O&M Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Determine whether ECDA has been applied previously to the pipeline segment.
   - Identify date of previous assessment.

c) If this is a first-time application of ECDA, more restrictive criteria is required. Define the more restrictive criteria to be utilized for the following:
- Pre-Assessment
- Indirect Inspection
- Direct Examination

d) Document the criteria and transmit to the Supervisor, Data Management for recordkeeping.

2 Gather data.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Gather data in accordance with Section 3.3 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Refer to Table 1: "ECDA Data Elements" in Section 3.3.

c) The data elements to be collected are grouped into five categories:
- Pipe related
- Construction related
- Soils/Environmental
- Corrosion control
- Operational data

d) The Typical sources for the data are listed. Other data sources may need to be used for data not available in the listed sources.
- Maximo
- PODS
- TOPS (Archived Database)
- Subject Matter Experts
- Alignment Sheets

e) Resolve data conflicts.

3 Perform ECDA feasibility assessment.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Refer to Section 3.4 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

c) Integrate and analyze the data collected in Step 1 to determine whether conditions exist for which indirect inspection tools cannot be used or that would make ECDA application difficult.
- ECDA is feasible.
- ECDA is not feasible.

d) Document analysis and review with Direct Assessment Manager. Transmit analysis to Supervisor, Data Management for recordkeeping.

4 Define ECDA segments and regions.

a) Primary responsibility: DA Specialist, O&M Specialist or Direct Assessment Manager

b) Identify the ECDA regions on the pipeline segment in accordance with Sections 3.5 and 3.6 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Refer to the example in Figure 2: "ECDA Segment and Region Definitions".

c) Define and document the definition criteria.

d) Identify and document the ECDA regions.

e) Transmit the definition criteria and identified regions to the Supervisor, Data Management for recordkeeping.

5 Select Indirect Inspection Tools.

a) Primary responsibility: DA Specialist or O&M Specialist

b) For the ECDA regions identified in Step 3, select the tools to be used for indirect inspection.
- See Section 3.7 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Refer to Table 2: "ECDA Tool Selection Matrix" in Section 3.7.

c) Document the tools selected and reasons for selection. Transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process A --

Process B - Indirect Inspection

<u>Step</u> **<u>Action and Discussion</u>**

1 Determine more restrictive criteria.

a) Primary responsibility: DA Specialist or O&M Specialist

b) In Process A Step 1, a determination was made whether this will be a first-time application of ECDA for the pipeline segment.

c) If this is a first-time application of ECDA, more restrictive criteria are required for indirect inspection. Define the more restrictive criteria to be utilized.
- Refer to Sections 3.9, 4.8, and 10.7 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

d) Document the criteria and transmit to the Supervisor, Data Management for recordkeeping.

2 Develop indirect inspection instructions for Field Team.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Develop indirect inspection instructions for conducting the survey.
- Identify the schedule for the survey.
- Identify start and end points.
- Identify tools
- Identify specific requirements for conducting the survey if this is a first-time application of the ECDA process to the pipeline segment.
- Identify minimum data requirements.

c) Transmit the instructions to the Field Team and transmit a copy to the Supervisor, Data Management for recordkeeping.

3 Perform indirect inspection.

a) Primary responsibility: DA Field Supervisor or DA Technician

b) Conduct the indirect inspection in accordance with the instructions.
- Clearly mark the boundaries of the ECDA region (start and end points)
- Calibrate the survey tools and perform the surveys.
- Verify accurate data is being recorded by the survey tools.
- Record aboveground locations using sub-meter accuracy GPS location meters.

c) Collect results of the survey tools and download to Company computer system ("ProActive").

4 Perform quality check of data collected during surveys.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Evaluate the quality of the data collected during the surveys.
- Was data collected for the entire length of the ECDA region?
- Are the results reasonable?

c) Determine whether the surveys need to be performed again or new tools selected.

d) Evaluate quality of data from new surveys or survey reruns.

e) Document the results of the quality check and send to the Supervisor, Data Management for recordkeeping.

5 Perform indirect inspection resurvey if needed.

a) Primary responsibility: DA Field Supervisor or DA Technician

b) Perform surveys again using same or different tools in accordance with Step 3 if so directed based on results of Step 4.

6 Spatially align data from the indirect inspection.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Spatially align the data from the surveys.
- Refer to Section 4.5 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

- Use the "Proactive" computer software to develop the Direct Assessment Alignment Sheet.

c) Document the data alignment. Provide discussion of any spatial alignment errors. Transmit the alignment document to the Supervisor, Data Management for recordkeeping.

7 Classify severity of indications.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Classify severity of indications.
- Use Table 3: "Severity Classification Table" in Section 4.5 of Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Consider known survey tool sensitivities.
- Identify and resolve inconsistencies in data between the survey tools.
- Classify indications both by individual tool and by combined tool.
- Use more restrictive classification criteria for first-time application of ECDA.

c) If data inconsistencies cannot be explained, consider rerunning the indirect inspection (repeat Steps 3, 4, and 6) or reevaluate the feasibility of using ECDA for the ECDA region (Step 8)

d) Document data inconsistencies and resolution, the severity classification, the criteria used, and reasoning for classification and transmit to the Supervisor, Data Management for recordkeeping.

8 Reevaluate feasibility of using ECDA to assess pipe integrity for the ECDA region.

a) Primary responsibility: DA Specialist or O&M Specialist

b) Compare the data collected in Process A: "Pre-Assessment" with the data collected in the indirect inspection.
   - Resolve data conflicts.
   - Document results of data comparison.

c) Use the results of the data comparison and the results of Step 6 to re-evaluate the feasibility of using ECDA for the ECDA region. Consider the conditions and criteria in Section 4.7 of Procedure PS-03-01-232: "External Corrosion Direct Assessment".

d) Document the feasibility reevaluation and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Direct Examination

Step **Action and Discussion**

1 **Determine more restrictive criteria.**

a) Primary responsibility: Pipeline Integrity Engineer or Direct Assessment Manager

b) In Process A Step 1, a determination was made whether this will be a first-time application of ECDA for the pipeline segment.

c) If this is a first-time application of ECDA, more restrictive criteria are required for direct examination. Define the more restrictive criteria to be utilized.
   - Refer to Sections 3.9, 4.8, and 10.7 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

d) Document the criteria and transmit to the Supervisor, Data Management for recordkeeping.

2 **Prioritize indications for direct examination.**

a) Primary responsibility: DA Specialist or O&M Specialist

b) For each indication identified in Process B: "Indirect Inspection", develop a priority ranking for direct examination.
   - Refer to Section 5.5 in Procedure PS-03-01-232: External Corrosion Direct Assessment".
   - Refer to Table 4: "Prioritization of Indirect Inspection Indications" in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

3 Develop schedule for direct examination of indications.

a) Primary responsibility: Direct Examination Supervisor or O&M Specialist

b) Determine the required number of direct examinations.
   - Refer to Section 5.7 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

c) Develop schedule for direct examination.
   - Use results of Steps 2b and 3b to develop prioritized list of digs.

d) Transmit schedule to Field Team for action and to Supervisor, Data Management for recordkeeping.

4 Perform direct examinations.

a) Primary responsibility: Direct Examination Supervisor (O&M Qualified Personnel)

b) Perform direct examination in accordance with the following process outline and procedures:
   - Process Outline: "Pipe Inspection, Defect Evaluation, and Pipe Repair".
   - Book 1, O&M, Procedure 235: "Exposed Pipe Examination".
   - Book 1, O&M, Procedure 226: "Pipeline Repairs - Existing In-Service Pipelines"
   - Procedure PS-03-01-242: "Dig Data Sheet".

c) Transmit all data generated during direct examination to Supervisor, Data Management for recordkeeping.

5 Perform root cause analysis.

a) Primary responsibility: DA Specialist, Direct Examination Supervisor or Direct Assessment Manager

b) Determine root cause for all significant corrosion activity.
- Refer to Section 9.0 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

c) Transmit root cause analysis to Supervisor, Data Management for recordkeeping.

6 Perform in-process evaluation.

a) Primary responsibility: DA Specialist or Direct Assessment Manager

b) Compare direct examination findings with indirect inspection indications.
- Evaluate prioritization criteria
- Evaluate classification criteria
- Refer to Section 10.0 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".

c) Revise prioritization criteria and classification criteria if required and perform additional direct examinations if required.

d) Reevaluate feasibility of using ECDA on the ECDA region based on results of direct examinations.

e) Document the in-process evaluation and transmit to the Supervisor, Data Management for recordkeeping.

7 Review direct examination data for follow-up actions.

a) Primary responsibility: External Corrosion Program Manager

b) Review results of all direct examinations and root cause analyses.
- Refer to Steps 4 and 5.

c) Develop and implement follow-up actions.
- Refer to Process Outline: "Pipe Inspection, Defect Evaluation and Pipe Repair".

-- End of Process C --

Process D - Post Assessment

<u>Step</u> **<u>Action and Discussion</u>**

1 Perform remaining life calculations.

a) Primary responsibility: DA Specialist or Direct Assessment Manager

b) Perform remaining life calculation.
- Refer to Section 11.4 in Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Refer to PS-03-01-260 "Reassessment Guidelines" for items to be considered when determining the reassessment interval.

c) Transmit calculations to Supervisor, Data Management for recordkeeping.

2 Determine reassessment intervals.

a) Primary responsibility: DA Specialist or Direct Assessment Manager

b) Calculate reassessment intervals.
- Refer to Section 11.5 in Procedure PS-03-01-232: "External Corrosion Direct Assessment"

c) Transmit calculations to Supervisor, Data Management for recordkeeping.

3 Assess ECDA effectiveness.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Identify additional dig locations for direct examination.
- Refer to Section 11.6 of Procedure PS-03-01-232: "External Corrosion Direct Assessment".
- Transmit dig locations to Field Team for action and to Supervisor, Data Management for recordkeeping.

c) Establish performance measures and consider optional measuring criteria.
- Refer to Section 11.6 of Procedure PS-03-01-232: External Corrosion Direct Assessment".

d) Evaluate direct examination data from additional digs (see Step "b)") when additional examinations are completed.

4 Prepare and issue final report.

a) Primary responsibility: DA Specialist or Direct Assessment Manager

b) Prepare final report for direct assessment of external corrosion for the assessed ECDA region.
- Summarize decisions, results, and evaluations.
- Organize by process: Pre-Assessment, Indirect Inspection, Direct Examination, and Post Assessment.

c) Transmit final report to Supervisor, Data Management for recordkeeping.

-- End of Process E --

Process E - Evaluation and Improvement

Step Action and Discussion

1 Review and evaluate the external corrosion direct assessment process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the overall process.
- All tasks necessary to implement the process are sufficiently identified.
- Additional tasks or supporting procedures are needed.

c) Describe the additional tasks or supporting procedures.

2 Review and evaluate the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review each task for completeness.
- Description of each task is sufficient.
- Additional details are needed to properly describe the task.
- Are new procedures needed to provide the details?

c) Describe the additional details needed.

3 Review and evaluate the referenced procedures that support the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the procedures for completeness.
- Procedures are sufficient to support the tasks.
- Additional steps need to be added to the procedures.
- Additional procedures are needed.

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the supporting documentation.
- Supporting documentation is sufficient.
- Additional supporting documentation is needed.
- Are additional forms needed?

c) Describe the additional supporting documentation needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the timeliness for performing the tasks.
- On-time completion percentages were acceptable.
- On-time completion percentages were not acceptable.

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Review the assigned primary responsibilities for each task.
- Assigned responsibilities are correct.
- Changes in assigned responsibilities are needed.

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: DA Specialist, Pipeline Integrity Engineer or Direct Assessment Manager

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
- Identify revised tasks and new tasks.
- Identify revised supporting procedures or new supporting procedures.
- Identify revised forms or new forms.
- Identify new supporting documentation and supporting documentation format changes.
- Identify changes to schedule for performing the process.
- Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process E --

INTRODUCTION

This process outline describes the steps necessary for developing and updating a prioritized remediation schedule.

Remediations are identified through the following processes:

- In-Line Inspection
- External Corrosion Direct Assessment
- Dry Gas Internal Corrosion Direct Assessment
- Stress Corrosion Cracking Direct Assessment

A prioritized remediation schedule is developed based on results from ILI surveys and direct assessments for external corrosion, internal corrosion and stress corrosion cracking. The schedule identifies the actionable anomalies based on data review and calculations performed during the conduct of the surveys and direct assessments.

The prioritized remediation schedule provides the following information:

- Location
- Defect details (corrosion, dents, seam, other)
- Date of survey or assessment
- Dig site selection date
- Date of Discovery
- Operating pressure at time of discovery
- Date of pressure reduction and value of reduction
- Projected date for return to normal operating pressure
- Required response time
- Date of excavation
- Date of remediation
- Remediation method

FREQUENCY OF USE

This process is implemented throughout the course of a year. The Director, Pipeline Integrity or Manager, Pipeline Integrity assigns the person responsible for implementation each year. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation is identified on the Process Tracking Document.

PROCESS

<u>Step</u> <u>Action and Discussion</u>

1 Identify digs for upcoming year.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Remediation

b) Identify and compile the digs generated from lists of digs identified during ILI Surveys and Direct Assessments.
- The Pipeline Integrity Engineer responsible for the survey or assessment identifies the defects that require investigation. The type and severity of the defect is identified during the survey or assessment.
- The identified digs are prioritized in accordance with Table 1 in Procedure PS-03-01-252: “Schedule of Repair Requirements”.

c) Prepare a Dig Summary Sheet for all defects classified as “Immediate Response” and “Scheduled Response”.
- Identify all digs (and remediations) that are required to be performed in the upcoming year.
- Identify all digs that can be scheduled in future years.

d) Identify scheduling constraints (operations logistics, time of year, resource availability, etc.)

2 Approve Dig Sheet Summary.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Remediation

b) Obtain approval of Manager, Pipeline Integrity.

c) Document approval and transmit to Pipeline Integrity - Supervisor, Data Management.

d) The Pipeline Integrity - Supervisor, Data Management transmits the Dig Sheet Summary to Engineering & Compliance - Project Management.

3 Schedule the Digs.

a) Primary Responsibility: Engineering & Compliance - Project Management

b) Project Management works with the Field Teams and System Control to schedule the digs for the upcoming year based on location, system operating constraints, regulatory requirements, time of year, etc.

4 Implement the Digs.

a) Primary responsibility: Field Teams

b) Execute digs in accordance with schedule.

c) Perform pipe inspection in accordance with Book 1, O&M, Procedure 235: “Exposed Pipe Examination”.

d) Record information obtained during dig using Procedure PS-03-01-242: “Dig Data Sheet”.

5 Complete Dig Sheet Summary.

a) Primary Responsibility: Engineering & Compliance - Project Management

b) Record the following information on the Dig Sheet Summary:
- Date of Excavation
- Date of Remediation
- Type of remediation performed

c) Transmit completed Dig Sheet Summary to Pipeline Integrity - Supervisor, Data Management.

-- End of Process --

INTRODUCTION

This process outline describes the steps necessary for conducting a review and update of prevention and mitigation measures that are applied to pipeline segments to alleviate pipeline integrity threats. It also includes steps for evaluating and improving the process.

The process involves the following procedures:
- PS-03-01-216: "Threat Identification and Risk Assessment"
- PS-03-01-258: "Preventive & Mitigative Measures"

The update accomplishes the following:
- Identifies and incorporates changes in requirements for P&M measures
- Identifies and incorporates changes in P&M measures selection process
- Identifies changes needed to implemented P&M measures
- Identifies new pipeline segments and associated new P&M measures
- Ensures P&M measures are scheduled and implemented

There are three processes associated with this outline:
Process A - Annual Update of P&M Measures
Process B - Process Review
Process C - Baseline Prevention & Mitigation Management

FREQUENCY OF USE

This process is implemented annually, or as directed by the Director, Pipeline Integrity or Manager, Pipeline Integrity. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

Process A - Annual Update of P&M Measures

Step **Action and Discussion**

1 Review regulatory environment.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review related codes, standards, and regulations
- Identify changes since previous P&M measures update.
- Document changes

c) Identify and document impacts.
- Are there changes to the P&M Measures process that need to be implemented?
- Are there changes to the Prevention and Mitigation requirements currently in use by the Company that need to be implemented?

2 Review industry knowledge base.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review published industry papers
- Research papers and experience reports from industry trade groups, research companies, other gas transmission companies.
- Review for new information (since previous P&M Measures update) concerning prevention and mitigation measures for pipeline integrity threats and consequences.

c) Identify and document potential impacts.
- Are there impacts to the P&M Measures process that need to be considered?
- Are there impacts to the prevention and mitigation requirements currently in use by the Company that need to be considered?

3 Review the Threat/Consequence List.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the Threat/Consequence List.
- The Threat/Consequence List is maintained under the Threat & Risk Assessment Element.
- Identify new threats and new or revised consequences.

c) Document review findings.

4 Update prevention and mitigation measures.

a) Responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Identify new or changed prevention and mitigation measures.
- Use results of steps 1, 2, and 3 of this Process.
- Also use input from the Process: “Continual Evaluation and Assessment”.

c) Update P&M Measures Selection Flowchart.
- See Procedure PS-03-01-258: “Preventive & Mitigative Measures” and associated form “Preventive and Mitigative Measures” in Section 3.4 of the procedure.

5 Select prevention and mitigation measures.

a) Responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Evaluate and select prevention and mitigation measures to be implemented
- Use latest Risk Model output from Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.
- Consider HCA segment-specific information from Risk Model output.
- Use “Prevention and Mitigation Measures” form in Section 3.4 of Procedure PS-03-01-258: “Preventive & Mitigative Measures”.
- Select measures by pipeline segment.

c) Review list of P&M measures to be used by Company with Operations.
- Incorporate Operations’ comments.
- Document agreement.

6 Schedule and implement P&M measures.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Use results of P&M measures selection process (Section 3.4: Prevention and Mitigation Measures” selection process flowchart in Procedure PS-03-01-258: Preventive & Mitigative Measures”) to provide Operations a list, by pipeline segment, of prevention and mitigation measures to be implemented.

c) Confirm that P&M measures have been scheduled (Maximo records).

d) Confirm that P&M measures have been implemented (Maximo records).

-- End of Process A --

Process B - Annual Update Process Review

<u>Step</u> **<u>Action and Discussion</u>**

1 Review and evaluate the Preventive & Mitigative Measures Annual Update process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the overall process.
- All tasks necessary to implement the process are sufficiently identified.
- Additional tasks or supporting procedures are needed.

c) Describe the additional tasks or supporting procedures.

2 Review and evaluate the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review each task for completeness.
- Description of each task is sufficient.
- Additional details are needed to properly describe the task.
- Are new procedures needed to provide the details?

c) Describe the additional details needed.

3 Review and evaluate the referenced procedures that support the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the procedures for completeness.
- Procedures are sufficient to support the tasks.
- Additional steps need to be added to the procedures.
- Additional procedures are needed.

c) Describe the changes needed to procedures and new procedures needed.

4 Review and evaluate the supporting documentation requirements associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the supporting documentation.
- Supporting documentation is sufficient.
- Additional supporting documentation is needed.
- Are additional forms needed?

c) Describe the additional supporting documentation needed. Identify any new forms that are needed.

5 Review and evaluate the timeliness of performing the tasks associated with the process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the timeliness for performing the tasks.
- On-time completion percentages were acceptable.
- On-time completion percentages were not acceptable.

c) Describe the timeliness issues and the changes needed.

6 Review and evaluate the roles (primary responsibilities) associated with each task.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Review the assigned primary responsibilities for each task.
- Assigned responsibilities are correct.
- Changes in assigned responsibilities are needed.

c) Describe the assigned responsibility changes needed.

7 Compile the review results and input to the Management of Change process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 6.
   - Identify revised tasks and new tasks.
   - Identify revised supporting procedures or new supporting procedures.
   - Identify revised forms or new forms.
   - Identify new supporting documentation and supporting documentation format changes.
   - Identify changes to schedule for performing the process.
   - Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Baseline Prevention & Mitigation Management

<u>Step</u> **<u>Action and Discussion</u>**

1 Review the damage prevention plan.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - P&M

b) Determine whether a damage prevention plan exists pursuant to 192.614.
   - Plan exists.
   - Plan does not exist.
   - Document answer. If plan does not exist, explain why not.

c) Determine whether the original damage prevention plan has been updated and migrated to the Public Awareness Plan.
   - Plan has been updated.
   - Plan has not been updated.
   - Plan has been migrated.
   - Plan has not been migrated.
   - Document answers. If plan has not been updated or migrated, explain why not.

d) Determine whether plan addresses conditions involving plastic pipe and pipe operating below 30% SMYS.
   - Plan addresses plastic pipe.
   - Plan does not address plastic pipe.
   - Plan addresses pipe operating below 30% SMYS.
   - Plan does not address pipe operating below 30% SMYS.
   - Document answers. If plan addresses plastic pipe and low pressure operation, describe use of qualified personnel, one-call system, excavation monitoring, and monthly patrols. If plan does not address plastic pipe and low pressure operation, explain why not.

2 Review 49 CFR 192.917 threat mitigation requirements.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Review requirements for mitigation of threats and consequences as outlined in 192.917.
   - Document the date of review.
   - Document the requirements.

c) Identify mitigation techniques currently being implemented by the Company.
   - Document the techniques being used (develop a spreadsheet)

d) Determine whether the mitigation activities and results are being monitored.
   - Mitigation activities are being monitored.
   - Mitigation activities are not being monitored.
   - Document answer. If activities are not being monitored, explain why not.

e) Determine whether the results of mitigation activities are being analyzed.
   - Results are being analyzed.
   - Results are not being analyzed.
   - Document answer. If results are being analyzed, explain how the results will affect the risk model. If results are not being monitored, explain why not.

f) Determine whether the risk model includes the ability to adjust the threat POF and consequence based on the results of the mitigation activities.
   - Risk model can be adjusted.
   - Risk model can not be adjusted.

- Document answer. If the risk model can be adjusted, explain how the model allows for adjustment. If the risk model can not be adjusted, explain why not.

g) Determine whether mitigation activity results are being inputted to the risk model.
- Results are being inputted.
- Results are not being inputted.
- Document answer. If not, explain why not.

3 Review 49 CFR 192 Subpart O requirements.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Determine whether prevention and mitigation techniques above and beyond those included in Subpart O exist for each threat/consequence.
- Techniques exist.
- Techniques do not exist.
- Document answer. If techniques exist, describe each one.

c) Perform feasibility study for new prevention and mitigation techniques not included in Subpart O.
- Document the feasibility study.

d) Perform cost effectiveness analysis for new prevention and mitigation techniques not included in Subpart O.
- Document the cost effectiveness analysis.

e) Using the results of “c)” and “d)” above, rank each technique by threat.
- Document the ranking.

f) Develop metrics to measure the effectiveness of each technique
- Describe the metrics.
- Document the metrics.

g) Determine whether the risk model includes the ability to adjust the threat POF and consequence based on the results of the additional mitigation activities.
- Risk model can be adjusted.
- Risk model can not be adjusted.
- Document answer. If the risk model can be adjusted, explain how the model allows for adjustment. If the risk model can not be adjusted, explain why not.

h) Determine whether the additional mitigation activity techniques are being inputted to the risk model.
- Techniques are being inputted.
- Techniques are not being inputted.
- Document answer. If not, explain why not.

4 Review system-wide threats versus segment-specific threats.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Determine whether the risk model includes system-wide threats.
- Risk model includes system-wide threats.
- Risk model does not include system-wide threats.
- Document answer. If system-wide threats are included, describe the threats and provide a threat ranking. If system-wide threats are not addressed by the risk model, explain why not.

c) For each threat, determine which mitigative technique will be applied system-wide.
- Develop a spreadsheet that describes the mitigation technique for each threat. If this is not implemented, explain why not.

d) Determine the threats applicable to specific pipeline segments.
- Develop a spreadsheet that describes the threats to specific pipeline segments. If this is not implemented, explain why not.

e) Determine relationship of segment-specific threats to system-wide threats.
- How do the segment-specific threats rank within the pipeline segment when compared to system-wide threats?
- Document answer with the risk model segment analysis.

f) Based on the comparison conducted in “e)” above, determine whether there are any segment-specific threats that rank higher than system-wide threats.
   - Develop spreadsheet that shows pipeline segments that require additional mitigation techniques and what the techniques are based on feasibility and cost effectiveness.
   - Develop a pipeline segment ranking and segment mitigation requirements.
   - If this is not implemented, explain why not.

5 Implement mitigation measures for each threat for each pipeline segment.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Develop schedule for mitigation measures implementation.
   - Address each threat for each pipeline segment.

c) Transmit schedule to Region Directors and Direct Assessment Manager for implementation and to Supervisor, Data Management for recordkeeping.

6 Compile the review results obtained in Process B and input to the Management of Change process.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Risk

b) Compile the results of the reviews and evaluations conducted in Steps 1 through 5.
   - Identify revised tasks and new tasks.
   - Identify revised supporting procedures or new supporting procedures.
   - Identify revised forms or new forms.
   - Identify new supporting documentation and supporting documentation format changes.
   - Identify changes to schedule for performing the process.
   - Identify organizational changes.

c) Document the review and evaluation results and transmit the input to the Management of Change process. Provide a copy of the documentation to the Supervisor, Data Management for recordkeeping.

-- End of Process C --

INTRODUCTION

This process is designed to evaluate assessment results, preventive and mitigative measures, and operating history to determine whether changes need to be made to assessment plans, assessment methods selected or P&M measure selection and implementation   The review may result in identified changes to the assessment plan, risk model, and assessment method.

The reassessment interval determinations are performed in the process outlines and associated procedures for the following:

- In-Line Inspection
- Pressure Testing for Assessment
- External Corrosion Direct Assessment
- Dry Gas Internal Corrosion Direct Assessment
- Stress Corrosion Cracking Direct Assessment

Procedure PS-03-01-260: “Reassessment Guidelines” provides guidelines and criteria for determining reassessment intervals and is referenced in the above assessment procedures.

Calculations and technical justifications for reassessment intervals are documented and maintained in the IMP recordkeeping system as part of each assessment and also reviewed as part of this process outline.

FREQUENCY OF USE

This process is implemented annually. The Director, Pipeline Integrity assigns the person responsible for implementation each year. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation is identified on the Process Tracking Document.

PROCESS

<u>Step</u>   <u>Action and Discussion</u>

1   Collect data.

a) Primary responsibility: Pipeline Integrity Engineer

b) Collect final reports for completed assessments, including reassessment documentation.
- Pressure Tests
- In-Line Surveys
- Direct Assessments

c) Collect operating history.
- Data sources:
  - System Control
  - Maximo
- Data elements
  - Leaks
  - Third party damage reports
  - Aboveground equipment failures
  - Cleaning pig run results
  - Pipe inspections
  - MOP history

d) Collect construction and pipe replacement information.
- Data sources
  - Pink envelopes
  - PODS
  - AFE system
- Data elements
  - Where
  - When
  - Why

e) Collect performance measures data.

f) Obtain copy of most recent risk assessment output.

g) Obtain list of currently identified P&M measures.

2 Analyze performance measures data to determine trends.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) Analyze data.
- Does the data indicate the Integrity Management Program is being implemented as planned?
- Are changes required in certain areas to meet the intent of the Integrity Management Program?

3 Evaluate operating, construction and assessment data.

a) Primary responsibility: Pipeline Integrity Engineer

b) Perform integrated review of the following items for the previous year:
- operating history
- construction activity
- assessment results

c) Use the results of b) above to evaluate potential changes in HCAs.
- Changes to preventive and mitigative measures implemented
- Method of assessment
- Schedule for conducting assessments

4 Determine changes.

a) Primary responsibility: Pipeline Integrity Engineer

b) Identify and document required changes based on evaluation conducted in Step 2.
- Changes required to P&M measures implementation.
- Changes required in method of assessment.
- Changes required in schedule for conducting assessments.

5 Review and approve evaluation results and recommended changes.

a) Primary responsibility: Manager, Pipeline Integrity

b) Review and approve recommended actions.

c) Provide documentation to Supervisor, Data Management for recordkeeping.

6 Prepare recommended changes for processing through MOC.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) For changes to processes and procedures, prepare a change request for processing through the Management of Change program.

7 Initiate recommended changes.

a) Primary responsibility: Pipeline Integrity Engineer

b) Provide input to Baseline Assessment Plan process so that revisions to assessment methods and schedules can be made to the annual assessment plan and long-term assessment plan

c) Provide input to the Annual Update of P&M Measures process so that revisions to the P&M measures selection list can be made.

d) Provide input to the Threat Identification and Risk Assessment Annual Update process so that revisions can be made to the risk model.

-- End of Process --

INTRODUCTION

This process outline describes the steps necessary for monitoring and reporting performance measures. Performance measures have been designed to monitor specific elements of data for measuring progress in implementation of the Integrity Management Program. Certain of the data are reported to the Pipeline and Hazardous Materials Safety Administration (PHMSA) semiannually.

FREQUENCY OF USE

This process is implemented twice each year, or as directed by the Director, Pipeline Integrity or Manager, Pipeline Integrity. Progress during process implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

<u>Step</u> **<u>Action and Discussion</u>**

1 Collect data.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) Collect data
- Data is collected twice each year (semiannually)
- Table 1 in Procedure PS-03-01-262: “Methods to Measure Program Performance” identifies the data points that are monitored.
- The reporting periods are January 1 through June 30, and July 1 through December 31.

2 Report performance measures to PHMSA.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) The following data are reported semiannually to PHMSA:
- Number of miles of pipeline inspected
- Number of immediate repairs completed
- Number of scheduled repairs completed
- Number of leaks, failures, and incidents (classified by cause)

c) The data is collected for January 1 through June 30 of each year and is reported by the Engineering & Compliance - DOT Compliance Manager to PHMSA by August 31.

d) The data is collected for July 1 through December 31 of each year and is reported by the Engineering & Compliance - DOT Compliance Manager to PHMSA by February 28.

e) Collect data from the following data sources:
- HCA List (inspection mileage)
- Maximo (leaks, failures, and repairs)
- IT Reports (leaks, failures, and repairs)
- DOT Compliance Manager (incidents)

f) Perform a quality check of the data collected.
- Re-review selected Maximo data
- Review individual event records
- Verify data is for the reporting time period
- Review HCA boundaries
- Review leak causes
- Review pipe inspection reports (immediate and scheduled repairs)
- Dig Summary Sheets (immediate and scheduled repairs)

g) Review semiannual performance data with Manager, Pipeline Integrity and send to the Senior Vice President Operations for review and written approval.

h) Send approved performance data to Supervisor, Data Management for recordkeeping and for transmittal to Engineering & Compliance – DOT Compliance Manager.

i) Verify transmittal of data to PHMSA
   - Obtain copy of Engineering & Compliance - DOT Compliance Manager transmittal to PHMSA
   - Send copy of transmittal to Supervisor, Data Management for recordkeeping.

3 Complete and submit INGAA IMP Impact Survey.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) Collect data
   - Mileage data
   - Assessment data
   - Dig data
   - Leak Repair History (use annual report to OPS)

c) Review survey data with Manager, Pipeline Integrity and submit to AGA.

d) Transmit copy of submitted data to Supervisor, Data Management for recordkeeping.

4 Evaluate performance measures process for improvement.

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) Review the performance measures process.
   - Identified steps are sufficient to implement process
   - Steps are missing (additional steps required - describe)

c) Review the supporting procedures.
   - Procedures for implementing process steps are sufficient
   - Procedures are missing key tasks (describe)
   - New Procedures are needed (describe)

d) Review the supporting documentation requirements
   - Supporting documentation is sufficient
   - Additional supporting documentation required (describe)

e) Review the timelines associated with the process
- On-time completion percentages are acceptable
- On-time completion percentages not acceptable (describe)

f) Review the roles (primary responsibilities) identified in the process.
- No role changes required
- Role changes required (describe)

5 Identify changes to performance measures process

a) Primary responsibility: Pipeline Integrity Engineer or Project Manager - Performance

b) Using the results of Step 6 above, determine the type of changes needed.
- Procedural
- Technical
- Physical
- Organizational

c) Prepare change requests for processing through the Management of Change program. For each change:
- Describe in detail the requested change.
- Describe why the change is needed.
- Describe the impact if the change is not implemented.

d) Submit changes for processing through the Management of Change program.

-- End of Process --

INTRODUCTION

This process describes the steps for developing and maintaining a recordkeeping system for records generated through implementation of the various Integrity Management Processes.

FREQUENCY OF USE

This process is implemented throughout the course of a year. The Director, Pipeline Integrity assigns the person responsible for implementation each year. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation is identified on the Process Tracking Document.

PROCESS

Step **Action and Discussion**

1 Develop a catalog structure.

a) Primary responsibility: Supervisor, Data Management

b) Use an electronic spreadsheet.

c) Review each process to determine the documents to be stored.
- Electronic documents
- Manually generated documents

d) Determine types of documents that are generated. Examples include:
- Spreadsheets
- Calculations
- Forms
- White papers
- Research papers
- E-mails
- Maps
- Data bases

e) Determine storage location for each document.

- Certain information will not be maintained in the IMP recordkeeping system since it is available on data bases maintained by the Company. Examples include: Maximo and PODS.
- Identify the source of information maintained in Company data bases such as Maximo and PODS.

f) The catalog spread sheet identifies the following:
- Document name or type
- PHMSA Protocol
- Hard copy location
- Electronic copy location
- Record keeping responsibility
- Retention duration

2 Maintain the catalog.

a) Primary responsibility: Supervisor, Data Management

b) Monitor documents transmitted to Data Management for recordkeeping.
- Review versus catalog structure for appropriateness of document description, type and file location.
- Periodically review IMP processes for changes to process or new processes.

c) Revise catalog structure based on reviews.

3 Implement recordkeeping.

a) Primary responsibility: Supervisor, Data Management

b) Receive and store IMP related documents generated through implementation of IMP and other Company processes and procedures.
- Electronic records
- Manually generated records
- Scan manually generated records to create computer accessible file
- Storage/disposition of originals
- Refer also to procedure PS-03-01-214: “Data Management” for recordkeeping requirements for specific types of documents and data.

-- End of Process --

INTRODUCTION

This process outline describes the actions necessary for managing and controlling changes made within the Company's infrastructure that may affect operation, maintenance or administration of the Company's natural gas transmission pipeline system. The management of change program ensures that changes are reviewed for impact on the integrity of the pipeline system and for impact on the Integrity Management Program so that follow-on actions can be identified and implemented if and, when necessary.

There are four processes described in this outline:

Process A - Procedure Change Management
Process B - Key Document Change Management
Process C - Pipeline System Change Management
Process D - Organizational Change Management

FREQUENCY OF USE

This process is implemented continually throughout the course of a year. The Director Pipeline Integrity each year reviews process oversight responsibilities and assigns personnel to be responsible for implementation of each of the four processes described herein. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for process implementation and the associated pipeline segment are identified on the Process Tracking Document.

PROCESS

Process A - Procedure Change Management

<u>Step</u> **<u>Action and Discussion</u>**

1 Receive change recommendation for processing.

a) Primary responsibility: Pipeline Integrity Engineer

b) Each of the processes for integrity assessment (In-Line Inspection, Pressure Testing, and Direct Assessment) has within the process a feedback component wherein the effectiveness of the process is assessed. Other processes, including those for key areas such as assessment planning, threat identification, risk assessment, remediation, prevention and mitigation measures, and performance measures have similar feedback loops for evaluating the effectiveness of the process. The intent of the feedback loops is to identify areas where the process can be improved or enhanced through changes in process or procedure.

c) Not all procedural changes are identified through the feedback loop mechanism. Some changes are caused by changes in regulations or standards identified during the annual update to the risk assessment and the assessment plans.

d) Recommendations for process or procedural changes are received via the feedback mechanisms or annual review/update cycles encompasses in the integrity management processes and procedures.

2 Prepare the change notification.

a) Primary responsibility: Pipeline Integrity Engineer

b) Prepare the change notification, including the process/procedure marked up with the proposed change, in accordance with the requirements specified in Procedure PS-03-01-266: “IMP Management of Change”.

3 Process the change.

a) Primary responsibility: Pipeline Integrity Engineer

b) Transmit the recommended change to the Management of Change (MOC) Committee for review and approval in accordance with the Company’s “High Level Management of Change” process.
   - The Director, Pipeline Integrity is a member of the MOC Committee and can provide status of change recommendations.

c) Transmit approved changes to the Supervisor, Data Management for recordkeeping.

- There is a Company MOC administrative group that handles all procedural changes reviewed and approved by the MOC Committee.

- The change is processed and published by the MOC administrative group, including establishing the timing for implementing the change, notification for employee training, and other such administrative matters.

-- End of Process A --

Process B - Key Document Change Management

<u>Step</u> <u>Action and Discussion</u>

1 Identify, process, and record changes to key IMP documents.

a) Primary responsibility: Pipeline Integrity Engineers assigned document ownership.

b) Table 1 in Procedure PS-03-01-266: "IMP Management of Change" identifies key documents that form the fabric of the Integrity Management Program. Changes to these key documents are controlled by the various processes and procedures that comprise the Program. Changes to any of these key documents shall be processed in accordance with Procedure PS-03-01-266 and recorded in a change log to be maintained by the document owner.

2) Perform review of change logs.

a) Primary responsibility: Supervisor, Data Management

b) Periodically review the changes to ensure the change logs are up to date and that change log information such as change description, reason for change, date of change is included.

c) Document results of review and file in recordkeeping system.

-- End of Process B --

Process C - Pipeline System Change Management

<u>Step</u>   <u>Action and Discussion</u>

Changes to the Company's pipeline system involve both physical changes, such as modifications and upgrades to pipe facilities, and also technical changes that include items such as increases in operating pressure, or changes in land use, or operating pressure fluctuations (cyclic loading).

1 Review AFE proposals/approvals.

a) Primary responsibility: Pipeline Integrity Engineer

b) An AFE is a document used by the Company to consider and approve engineering projects. Review of these documents by Pipeline Integrity ensures that changes to the pipeline system are reviewed for their effect on the integrity of the pipeline system and their effect on the Integrity Management Program.

c) Review the AFE for impact on the integrity of the pipeline system.
- Describe the impact, if any, and input the impact to the Process: "Continual Evaluation and Assessment".
- Transmit the documented impact to the Supervisor, Data Management for recordkeeping.

d) Review the AFE for impact on the Integrity Management Program.
- Describe the impact, if any, and input the impact to the Process: "Continual Evaluation and Assessment".
- Transmit the documented impact to the Supervisor, Data Management for recordkeeping.

2 Review changes in land use.

a) Primary responsibility: Pipeline Integrity Engineer

b) Review the Annual Population Density and HCA Field Survey data to determine changes in land use. Changes in land use can impact both the consequence of an incident or the likelihood of an incident. Changes in land use include items such as increasing populations, new structures, and new industries.

c) Document the change and transmit to the Supervisor, Data Management for input to the HCA Identification process and for recordkeeping.

3 Review changes in operating pressure.

a) Primary responsibility: Pipeline Integrity Engineer

b) Annually review operating pressure increases above the maximum operating pressure experienced during the five years preceding identification of the HCA (Refer to Section 2.5 in Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.

- For pipelines without a previous Subpart J hydrotest, a list is maintained of the maximum operating pressures experienced during the five year period preceding the date the HCA was identified.

- For pipelines without a previous Subpart J hydrotest, the Company gathers the maximum operating pressure data each year after the HCA has been identified.

- Compare the list of operating pressures before HCA identification to the list of operating pressures after HCA identification.

- Document occasions where post-HCA operating pressure exceeded pre-HCA operating pressure. Input the information to the Threat Identification and Risk Assessment process and transmit to the Supervisor, Data Management for recordkeeping.

c) Annually review MAOP increases.

For pipelines without a previous Subpart J hydrotest, MAOP data is gathered each year and compared to a list of the same information for the previous year.

- Based on the review, document the MAOP increases and input to the Threat Identification and Risk Assessment process and transmit to the Supervisor, Data Management for recordkeeping.

4 Annually review changes in operating conditions (pressure fluctuations) that could lead to cyclic fatigue.

a) Primary responsibility: Pipeline Integrity Engineer

b) Obtain from Gas Control list of changed operating conditions.

c) Evaluate the operating condition changes for impact to the integrity of the pipeline system and for impact to the Integrity of the Integrity Management.

d) Document the operating condition changes and input to the Threat Identification and Risk Assessment process and transmit to the Supervisor, Data Management for recordkeeping.

-- End of Process C --

Process D - Organizational Change Management

Step Action and Discussion

1 Review organizational changes.

a) Primary responsibility: Company Process Coordinator

b) Monitor e-mails for changes to the organization that may have an effect on the integrity of the pipeline system or an effect on the Integrity Management Program.

c) Identify and document the organizational change with potential impact and transmit to the Director, Pipeline Integrity for information/action and to the Supervisor, Data Management for recordkeeping.

-- End of Process D --

INTRODUCTION

This process outline describes the steps necessary for conducting quality audits and certain data reviews.

There are three separate processes described:

- Process A - Quality Audit
- Process B - External Contractor Quality Review
- Process C - Annual Dig Data Validation

The Company's Quality Program consists of the following:

Quality Assurance - Quality assurance is a programmatic review to determine whether an organization is properly implementing its processes and procedures. This is a compliance review. The second part of quality assurance is determining whether the processes and procedures being implemented achieve the desired outcome. This is an effectiveness review. The Company has developed this process outline for conducting the compliance reviews through audits. The effectiveness reviews are conducted as part of each of the individual processes that implement the integrity management program.

Quality Control - Quality control is the second major component of the Company's Quality Program. Quality control consists of a series of checks and balances that ensure that the steps in the processes and procedures are being implemented such that the desired results are achieved. These checks and balances are part of the individual processes. For example, the Process Tracking Documents are a major component of quality control since they serve as a check that each step was completed and the desired work products were produced and filed. Another example is Process C in the Quality Assurance process which is for a review for accuracy of all data collected during pipe excavations. Additionally, the process outlines contain similar steps for reviewing data, work products and decisions, which are all part of quality control.

FREQUENCY OF USE

This process is implemented once every two years, or as directed by the Director, Pipeline Integrity. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

<u>Step</u> <u>Action and Discussion</u>

Process A - Quality Audit

1 Schedule the quality audit.

a) Primary responsibility: Director, Pipeline Integrity

b) There are three types of quality audits that are characterized by who is on the audit team.

- Internal Audit - The audit is conducted by employees in the Pipeline Integrity group.
- External Company Audit - The audit is conducted by Company employees not associated with Pipeline Integrity (the audit team leader must be from outside the Pipeline Integrity group and audit team members may include one or more Pipeline Integrity employee who cannot audit any area under their direct responsibility).
- External Third Party Audit - The audit is conducted using a third party contractor to conduct the audit.

c) Select type of audit (internal, external, third party) and audit team leader.

d) Develop schedule with the audit team leader for collecting information and data, and for reporting audit results.

2 Perform annual quality audit.

a) Primary responsibility: Audit Team Leader

b) Conduct the audit in accordance with Section 2.5 and Appendix A in Procedure PS-03-01-268: “IMP Quality Assurance”, and the schedule developed in Step 1 above.

c) The audit is a spot check of records, not a 100% review of all records.

3 Conduct exit meeting.

a) Primary responsibility: Audit Team Leader

b) The exit meeting is conducted following the audit data collection period in accordance with the schedule developed in Step 1 above.

c) The exit meeting is used to provide preliminary findings and action items.

4 Develop and implement action plan.

a) Primary responsibility: Director, Pipeline Integrity

b) Develop an action plan to collect information that better demonstrates compliance with audit finding.

c) Compile information and transmit to the Audit Team Leader for consideration by audit team

d) Develop action plan to change processes and procedures, collect new data, add supporting documentation, etc., for deficiencies identified by the audit team that Pipeline Integrity agrees with.

e) Use form PS8144: “Action Item Tracking” to record planned actions (see Procedure PS-03-01-268: “IMP Quality Assurance”, Section 2.5).

5 Prepare and issue final audit report.

a) Primary responsibility: Audit Team Leader

b) Prepare final audit report based on audit review.

c) Consider supplemental information provided by Pipeline Integrity to audit team in Step 4 above.

d) Transmit final audit report to Director, Pipeline Integrity.

6 Update action plan.

a) Primary responsibility: Director, Pipeline Integrity

b) Update the action plan developed in Step 4 above based on the final audit report.

c) Assign personnel responsible for implementing each action.

d) Track actions through to completion.

e) Transmit final audit report and action plan to Supervisor, Data Management for recordkeeping.

-- End of Process A --

Process B - External Contractor Quality Review

<u>Step</u> **<u>Action and Discussion</u>**

1 Identify companies performing pipeline integrity work on a contractual basis.

a) Primary responsibility: Director, Pipeline Integrity or Project Manager - Contractor Quality Review

b) Identify each contractor performing pipeline integrity work. Examples include:
- In-Line Inspection (ILI) Survey Contractor
- Non-destructive testing contractors

c) Identify scope of work for each contractor.
- Contract documents

2 Conduct the review.

a) Primary responsibility: Director, Pipeline Integrity or Project Manager - Contractor Quality Review

b) Verify that quality control checks are defined for each contract. Review the following:
- Contract documents
- Processes (Company and contractor, as applicable)
- Procedures (Company and contractor, as applicable)
- Specifications (Company and contractor, as applicable)

c) Verify that the quality control checks are performed. Review the following:
- Contract documents
- Processes (Company and contractor, as applicable)
- Procedures (Company and contractor, as applicable)
- Specifications (Company and contractor, as applicable)
- Supporting documentation for above

3 Prepare review report.

a) Primary responsibility: Director, Pipeline Integrity or Project Manager - Contractor Quality Review

b) Prepare individual reports for each contractor.

c) Transmit reports to each contractor for action and to Supervisor, Data Management for recordkeeping.

4 Monitor findings for resolution.

a) Primary responsibility: Director, Pipeline Integrity or Project Manager - Contractor Quality Review

b) Monitor contractor responses to review findings and actions to address findings.

c) Record contractors' planned actions using form PS8144: "Action Item Tracking" (see Procedure PS-03-01-268: "IMP Quality Assurance", Section 2.5).

d) Track planned actions through to completion using form PS8144.

e) Transmit completed PS8144 forms to Supervisor, Data Management for recordkeeping.

-- End of Process B --

Process C - Personnel Qualifications

Step Action and Discussion

1 Review personnel qualification requirements.

a) Primary responsibility: Director, Pipeline Integrity

b) Review personnel qualification requirements in Procedure PS-03-01-272: "IMP Personnel Qualification Requirements"
- Table 1: "Qualification Requirements Matrix"
- Sections 2.4 through 2.11 inclusive

c) Identify new or changed qualification requirements based on regulatory requirements, Company standards, and industry standards.

d) Prepare a change request for processing through the Management of Change program.
- Describe in detail the requested change.
- Describe why the change is needed.
- Describe the impact if the change is not implemented.

2 Review individual statements of qualification.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Using the results of the review conducted in Step 1, each director, manager, and supervisor reviews the individual statements of qualification for all Pipeline Integrity personnel reporting to them.
- Personnel records review

3 Identify qualification deficiencies for each employee.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Identify qualification deficiencies for each employee.

c) Develop action plan for each employee for resolving the deficiency (example: take additional training courses)

d) Transmit action to each employee and to Supervisor, Data Management for recordkeeping.

4 Track employee action plans.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Track each employee action plan to ensure qualification requirements are attained.

c) Document completion of action plans and transmit to Director, Pipeline Integrity for review and to Supervisor, Data Management for recordkeeping.

-- End of Process C --

INTRODUCTION

This process describes two annual reviews that are conducted to ensure that qualification requirements for each position in the Pipeline Integrity organization have been defined and that employees filling the positions have met the requirements.

FREQUENCY OF USE

This process is implemented annually, or as directed by the Director, Pipeline Integrity. Progress during implementation is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation each year is identified on the Process Tracking Document.

PROCESS

Step **Action and Discussion**

1 Review the organization chart for Pipeline Integrity to ensure it is accurate and up to date.

a) Primary responsibility: Director, Pipeline Integrity

b) Company organization charts are maintained by Human Resources and are available on the Company Intranet.

c) Review for the following:
- Are reporting relationships accurately shown?
- Are position titles correct?
- Are personnel accurately identified on the organization chart?

d) Transmit updates and corrections to Human Resources for action and to the Supervisor, Data Management for recordkeeping.

2 Review the qualification requirements for each position identified on the organization chart.

a) Primary responsibility: Director Pipeline Integrity

b) Table 1: "Qualification Requirements Matrix" in Procedure PS-03-01-272: "IMP Personnel Qualification Requirements" identifies the education, experience, training, certification and other qualification requirements for each position title. Sections 2.4 through 2.11 in Procedure PS-03-01-272 provide detailed notes of explanation for Table 1.

c) Review the requirements identified in Table for the following:
- Are the positions identified in Table 1 the same as the organization chart?
- Are there new or revised education requirements for any identified position?
- Are there new or revised experience requirements for any identified position?
- Are there new or revised training requirements for any identified position?
- Are there new or revised certification requirements for any identified position?

d) Identify and document any revisions needed to either Table 1 or Procedure Sections 2.4 through 2.11. Transmit the revisions to the Supervisor, Data Management for recordkeeping and input the revisions to the Company Management of Change process for revision of Procedure PS-03-01-272.

3 Review individual statements of qualification.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Using the results of the review conducted in Steps 1 and 2, each director, manager, and supervisor reviews the individual statements of qualification for all Pipeline Integrity personnel reporting to them.
- Personnel records review

4 Identify qualification deficiencies for each employee.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Identify qualification deficiencies for each employee.

c) Develop action plan for each employee for resolving the deficiency (example: take additional training courses)

d) Transmit action to each employee and to Supervisor, Data Management for recordkeeping.

5 Track employee action plans.

a) Primary responsibility: Director, Pipeline Integrity; Manager, Pipeline Integrity; Manager, Direct Assessment; Corrosion Program Manager; other Pipeline Integrity managers and supervisors

b) Track each employee action plan to ensure qualification requirements are attained.

c) Document completion of action plans and transmit to Director, Pipeline Integrity for review and to Supervisor, Data Management for recordkeeping.

-- End of Process --

INTRODUCTION

This communications process describes three categories of communications:

- Communication with the public
- Communication within the Company
- Communication with PHMSA, or other regulatory agencies

Communication with the public and internal Company communication are proactive in nature and designed to provide general information about pipeline safety to the public and status of the Integrity Management Program to Company employees.

Communication with PHMSA is, in part, required by Subpart O. Other communication with PHMSA, or other regulatory agencies is in response to safety concerns raised by regulators.

This outline is comprised of 4 processes:
Process A - Communication with the Public
Process B - Internal Company Communications
Process C - Addressing Regulator-originated Safety Related Concerns
Process D - Notifications to PHMSA Required by Subpart O

FREQUENCY OF USE

This process is implemented annually, periodically throughout the year. Progress during implementation of the process is tracked using the companion Process Tracking Document and ICAM. The person responsible for implementation is identified on the Process Tracking Document.

PROCESS

Process A - Communication with the Public

Step **Action and Discussion**

1 Conduct annual planning meeting.

a) Primary responsibility: Director, Pipeline Integrity

b) Meet with Public Awareness Team to review last year's communications and plan the communication for the upcoming year.

c) Identify who was communicated to
- Affected public
- Public officials
- Emergency responders
- Excavators

d) Identify, for each group identified in “c)” above, when the communication took place, what was communicated, and method of delivery.

e) Document “c)” and “d)” above and transmit to Supervisor, Data Management for recordkeeping.
- Develop history file of annual communications plans.

f) Develop new communications plan for upcoming year.
- Identify targeted groups.
- Identify the messages to be delivered.
- Identify timing of the communications.
- Identify methods of delivery.

g) Transmit new communication plan to the Supervisor, Data Management for recordkeeping.

h) Provide technical information as requested to the Public Awareness Team for development of the communication messages.

2 Monitor implementation of Communication Plan.

a) Primary responsibility: Director, Pipeline Integrity

b) Obtain copies of communications documents from Public Awareness Team.

c) Attach supplemental information to communications documents about targeted groups, when delivered and how delivered.

d) Transmit communications documents and supplemental information to Supervisor, Data Management for recordkeeping.

Process B - Internal Company Communications

Step **Action and Discussion**

1 Develop annual internal communication plan.

a) Primary responsibility: Director, Pipeline Integrity

b) Develop annual communication plan.
- Scope
- Audience
- Timing and frequency
- Delivery method

c) Scope of message (status report) to include:
- Performance measures
- Plans for future activities
- Program changes

d) Determine targeted audiences
- Management
- Stakeholders in other departments
- Pipeline Integrity employees

e) Determine schedule by audience
- Annually
- Semiannually
- Quarterly
- Monthly

f) Determine method of delivery
- Company eNewsletter
- E-mail
- Meetings

2 Prepare status report.

a) Primary responsibility: Director, Pipeline Integrity

b) Performance measures status.
- Select several performance measures from Table 1 in Procedure PS-03-01-262: “Methods to Measure Program Performance
- Progress versus Subpart O five- and ten-year baseline inspection requirements

c) Major changes to Integrity Management Program
- Changes in Subpart O requirements
- Changes in requirements interpretations (FAQs)
- PHMSA notices/bulletins
- PHMSA audit findings

d) Near-term activities
- Summary of annual assessment plan

3 Deliver message.

a) Primary responsibility: Director, Pipeline Integrity

b) Deliver message.
c) Transmit message and supporting documentation to Supervisor, Data Management for recordkeeping.

Process C - Addressing Regulator-originated Safety Related Concerns

Step Action and Discussion

1 Receive and distribute communication from PHMSA or other state or local pipeline safety authority.

a) Primary responsibility: Engineering & Compliance - DOT Compliance Manager

b) Receive and log in communication.

c) Based on preliminary review, distribute communication to appropriate Company stakeholders.

d) Schedule meeting with stakeholders.

2 Meet with stakeholders.

a) Primary responsibility: Engineering & Compliance - DOT Compliance Manager

b) Conduct meeting with stakeholders
- Review communication for complete understanding
- Is a response required?
- Are there questions to be answered?
- Are there data to be provided?
- Are there procedural or programmatic actions to be taken?

c) Assign responsibilities for actions.

d) Determine due date for actions.

3 Identify planned response.

NOTE: This step is applicable to Pipeline Integrity only insofar as Pipeline Integrity may be involved with responding to the communication.

a) Primary responsibility: Director, Pipeline Integrity

b) Conduct meeting to discuss planned response to communication.
- Agree on response to be developed
- Assign responsibilities for developing response to Pipeline Integrity employees, as appropriate.
- Assign due date for completing response.

4 Develop response.

NOTE: This step is applicable to Pipeline Integrity only insofar as Pipeline Integrity may be involved with responding to the communication.

a) Primary responsibility: Pipeline Integrity Engineer assigned responsibility for developing response

b) Develop response.
- Collect and compile data as needed.
- Prepare position paper as needed.
- Initiate process or procedural revisions as needed.

c) Review prepared response with Director, Pipeline Integrity.

d) Transmit prepared response to Engineering & Compliance - DOT Compliance Manager

e) Transmit prepared response and supporting documentation to Supervisor, Data Management for recordkeeping.

5 Prepare transmittal to regulator.

a) Primary responsibility: Engineering & Compliance - DOT Compliance Manager

b) Prepare letter to regulator in response to communication.

c) Transmit letter to regulator and to Company stakeholders that provided input to response.

Process D - Notifications to PHMSA Required by Subpart O

Step Action and Discussion

1 Ensure required notifications are implemented.

a) Primary responsibility: Director, Pipeline Integrity

b) Required notifications are identified in Section 2.3 of Procedure PS-03-01-264: “IMP Communication Plan”.
- Inability to meet baseline assessment schedule
- Notification of intent to use Other Technology

- Significant changes in the Integrity Management Program
- Inability to meet remediation schedules
- Waiver for longer than seven-year reassessment schedule

c) Assign responsibility and due date for preparing notification.

2 Prepare and transmit notification.

a) Primary responsibility: Pipeline Integrity Engineer responsible for preparing notification

b) Prepare notification.
- Collect and compile data as needed.
- Develop supporting information as needed.
- Provide basis or analysis as needed.

c) Obtain approval of notification
- Director, Pipeline Integrity signs transmittal letter.

d) Transmit notification to PHMSA

e) Provide copy of notification to Engineering & Compliance - DOT Compliance Manager for information and to Supervisor, Data Management for recordkeeping.

-- End of Process --

1.0 PURPOSE

1.1 This procedure describes the process used for identifying segments of natural gas transmission pipelines in high consequence areas (HCAs).

1.2 This procedure complies with the requirements and guidelines contained in the Department of Transportation 49 CFR, Part 192 regulations for pipeline integrity management and ASME B31.8S guidelines for managing system integrity of gas pipelines.

2.0 PROCEDURE

2.1 There are two key components of the definition of an HCA. These are Identified Sites and Potential Impact Circles. Additionally, house count and population density are major contributing factors to these key components. These terms are defined and their relationships to how an HCA is identified are explained later in this procedure.

2.2 An HCA is defined (CFR 49, Part 192, Subpart O) by one of two methods:

2.2.1 Method 1

- An area defined as a Class 3 location under CFR 49, Part 192.5, or
- An area defined as a Class 4 location under CFR 49, Part 192.5, or
- Any Class 1 or Class 2 location where the potential impact radius is greater than 660 feet, and the area within a potential impact circle contains 20 or more buildings intended for human occupancy, or
- Any Class 1 or Class 2 location where the area within a potential impact circle contains an identified site.

2.2.2 Method 2

- The area within a potential impact circle containing 20 or more buildings intended for human occupancy, or

- The area within a potential impact circle containing an identified site.

2.2.3 The method selected is individual to each pipeline segment. The same method does not have to be used over an entire pipeline, or over a total pipeline system.

2.2.4 The initial HCA identification process utilized a mixture of Method 1 and Method 2. Since January 1, 2006, the Company has only used Method 2 for HCA identification. Method 2 will be used unless approval has been obtained to use Method 1 from the Manager, Pipeline Integrity.

2.3 Identified Sites

An Identified Site means each of the following areas (see CFR 49, Part 192, Subpart O for exact definitions):

2.3.1 An outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12-month period (the days need not be consecutive). Examples include, but are not limited to, beaches, playgrounds, recreational facilities, campgrounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility.

2.3.2 A building that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or skating rinks.

2.3.3 A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include, but are not limited to, hospitals, prisons or jails, schools, day-care facilities, retirement facilities or assisted-living facilities.

2.4 Defining the Potential Impact Circle

2.4.1 A Potential Impact Circle (PIC) is a circle within which a pipeline failure could have a significant impact on people or property. The radius of the PIC shall be calculated for each pipeline segment and is based on the following formula:

$r = 0.69 \bullet d \bullet \sqrt{p}$

Where:
r = radius of the potential impact circle in feet
0.69 = natural gas constant*
d = outside diameter of the pipe in inches
p = maximum allowable operating pressure (MAOP) of the pipe segment in psig

Sample calculation:

A 30-inch diameter pipe with an MAOP of 1,000 psi has a potential impact radius of 654.6 feet:

$r = 0.69 \bullet d \bullet \sqrt{p}$

$r = 0.69 \bullet (30 \text{ in.}) \bullet (1000 \text{ lb/in}^2)^{1/2}$

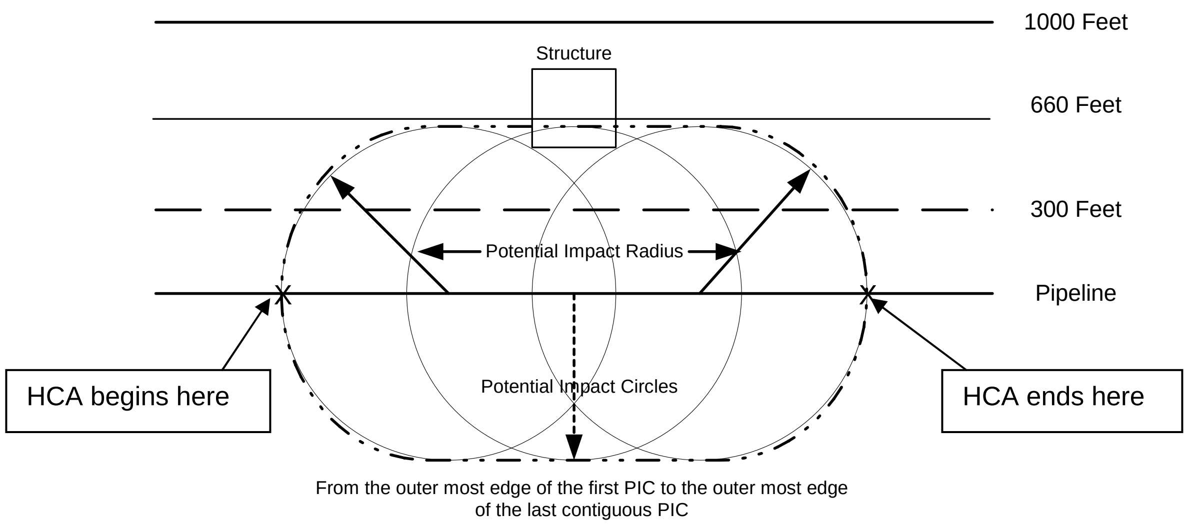
$r = 0.69 \bullet 948.68 = 654.6$ feet

*0.69 is the equation factor for natural gas. The origin of the equation factor calculation is in ASME B31.8S. This equation factor is mandated by CFR 49, Part 192, Subpart O.

2.5 Applying the Potential Impact Circle

2.5.1 The Potential Impact Circle is applied to the pipeline segment extending axially along the length of the pipeline as shown in Figure 1 below. The length of the HCA begins at the outermost edge of the first Potential Impact Circle that either touches an Identified Site or contains 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous Potential Impact Circle that either touches an Identified Site or contains 20 or more buildings intended for human occupancy.

FIGURE 1
Potential Impact Circle



2.6 Identifying an Identified Site

The Identified Site is identified in several ways:

2.6.1 From general familiarization of the areas through which the pipeline is routed. This is primarily accomplished during the Annual Population Density and HCA Field Surveys (refer to Book 1, O&M Manual, Procedure 219: "Population Density and HCA Field Survey" and PS-03-01-105: "HCA – Class Review" for additional guidance).

2.6.2 From public officials with safety or emergency response or planning responsibilities who indicate that they know of locations that meet the Identified Site criteria. These officials could include officials on a local emergency planning commission (LEPC) or relevant Native American tribal officials (refer to paragraph 2.8.3 and PS-03-01-105: "HCA – Class Review" for additional guidance).

2.6.3 If information is not obtainable by the methods described above, one of the following must be used to identify an Identified Site:

- Visible marking (for example, a sign), or
- The potential Identified Site is licensed or registered by a Federal, State, or local government agency, or
- The potential Identified Site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public (refer to paragraph 2.7 and PS-03-01-105: "HCA – Class Review" for additional guidance).

2.7 The Electronic (Internet) Search for Identified Sites

2.7.1 The electronic search is a search conducted on the Internet to identify and locate potential Identified Sites not readily apparent during other HCA identification processes.

- An appropriate data source or registry is identified by internet search of each category of structure. Information on potential Identified Sites is retrieved from the internet searches and compiled.
- A list of all zip codes in which Company-owned pipelines are located is generated.
- The list of potential Identified Sites is compared to the applicable zip codes. The appropriate potential Identified Site lists are provided to the Field Teams.
- The internet search will be accomplished every two years.
- The internet search categories are shown in Table 1:

TABLE 1
Internet Search Categories

Type of identified Site	Federal	State	County/ Parish	City
Outdoor Areas/Open Structures				
Beaches	FI	FI	FI	FI
Playgrounds	FI	FI	FI	FI
Recreational Facilities	FI	FI	FI	FI
Campgrounds	FI	FI	FI	FI
Outdoor Theaters	FI	FI	FI	FI
Stadiums	FI	FI	FI	FI
Recreational Areas near Water	FI	FI	FI	FI
Buildings with > 20 People				
Religious Facilities	X	X	X	X
Office Buildings	FI	FI	FI	FI
Community/Youth Centers	FI	FI	FI	FI
Commercial Establishments	FI	FI	FI	FI
Buildings with Limited Mobility				
Hospitals	FI	FI	FI	FI
Prisons	FI	FI	FI	FI
Schools	FI	FI	FI	FI
Daycare Centers	X	X	X	X
Retirement Facilities	X	X	X	X

Notes: FI = Field Identified
X = Internet Search Identified
Any potential Identified Site discovered during field visits or via electronic means should be fully investigated, regardless of Table 1 assignments.

2.8 HCA Updates

2.8.1 The following records shall be reviewed and analyzed to determine whether there are impacts on pipeline segments that potentially affect HCAs.

- Changes in pipeline maximum allowable operating pressure (MAOP).
- Pipeline modifications affecting pipe diameter.
- Changes in the commodity transported in the pipeline.
- Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional Identified Sites.
- Change in the use of existing buildings (for example, hotel or house converted to nursing home).
- Installation of new pipeline.
- Change in pipeline class location (for example, Class 2 to Class 3) or class location boundary.
- Pipeline reroutes.
- Corrections to erroneous pipeline centerline data.

2.8.2 An annual population density and HCA field survey (Book 1, O&M Manual, Procedure 219: “Population Density & HCA Field Survey) will be performed to update existing HCAs and to identify new HCAs.

2.8.3 A mail-out to local emergency response planning commission officials and/or Native American tribal officials (refer to paragraph 2.6.2 and PS-03-01-105: “HCA – Class Review” for additional guidance).

2.8.4 An electronic (internet) search per Table 1 in Section 2.7 (refer to PS-03-01-105: “HCA – Class Review” for additional guidance).

2.8.5 Newly identified HCAs and revised HCAs resulting from the above reviews and analyses shall be incorporated into the Long Term Assessment Plan within one year from the date the new HCA area was identified. New HCA area will also be added to the HCA Segment Plan (see paragraph 2.10.3).

2.8.6 When existing HCAs expand, the new expanded areas will be considered part of the original HCA. If the original HCA has already been assessed, the new expanded portion will be assessed when the original HCA is scheduled for re-assessment or within 10 years (whichever is less). If the original HCA has yet to be assessed, the new expanded portion will be assessed when the original portion is assessed.

2.9 New Pipeline Construction, Pipeline Reroutes Pipeline replacements, and Acquired Pipelines.

2.9.1 The construction projects and acquisitions referenced in this procedure include, but are not limited to:

- Those projects requiring the Company to purchase new Right of Way (ROW) or easement.
- Those projects installed in a new ROW, easement or utility corridor provided by others.
- Projects within existing ROW or easements that involve a new pipeline or altering the diameter or MAOP of an existing pipeline.
- Pipelines the Company purchases or acquires which are already constructed.

2.9.2 Determination of HCA boundaries and Class Location areas for construction and acquisition projects requires enough data to analyze the pipeline route for possible identified sites and population concentrations.

Typical data needed for analysis is:

- Recent aerial or satellite photographic imagery. Photographic images available on the intranet may be used.
- Proposed pipeline centerline.

- Maps and drawings with scale sufficient to draw the 1,320' corridor and the PIR along the pipeline route.
- Proposed pipe diameters and MAOP.

2.9.3 Population density survey shall be performed:

- By qualified Company employees or contractors. Pipeline Integrity personnel may accomplish the field survey.
- The survey shall be conducted per Operations and Maintenance Book 1, Procedure 219: "Population Density and HCA Field Survey".
- Identified Site Sheets will be completed when required and must include the distance from the proposed pipe centerline.

2.9.4 The Project Manager shall forward the Population Density Survey results, alignment sheets and Identified Site Sheets to Pipeline Integrity for review and determination of Class Location areas and HCA boundaries.

- This step is not required if Pipeline Integrity accomplishes the field survey.

2.9.5 Pipeline Integrity will perform the Class Location and HCA Review per the following:

- The Class Locations and HCA boundaries will be determined in accordance with Company processes and procedures.
- The Class Location and HCA Template may augment CFR 49, but CFR 49 guidance has priority.

2.9.6 Pipeline Integrity will forward preliminary HCA area and Class Location information to the Project Manager.

- If reroutes are required, repeat steps 2.9.2 thru 2.9.6.
- The Project Manager will inform Pipeline Integrity when the pipe route is finalized.

2.9.7 Pipeline Integrity will forward a list of the projected final HCA boundaries and Class Location areas to Data Integrity.

- Data Integrity will input the information into the Asset Inventory Database upon resolving the Construction Stationing with the As-Built Stationing.

- After construction, Maintenance Management System (MMS) will initiate the annual Population Density and HCA Field Survey cycle.

2.10 Documentation

2.10.1 The following information collected during the HCA Identification process shall be recorded in the Asset Inventory Database and/or displayed on the alignment sheets (unless otherwise noted). This information shall be collected and recorded during the annual assessment update.

- The method (Method 1 or Method 2) used to define the HCA shall be recorded in the Asset Inventory Database.

- The PIR shall be recorded in the alignment sheet legend and the radius distance displayed by a dashed line on the alignment sheet.

- The date the HCA was identified, or discovered, shall be recorded on the HCA Change Log. The date displayed in the Asset Inventory Database will be the date of the last revision to the HCA, but all dates of modifications will be reflected in the database history.

- The maximum allowable operating pressure (MAOP) or the maximum operating pressure for the five years preceding the HCA date of identification shall be recorded. This information, necessary for evaluation of construction and manufacturing threats, may be identified at a later date as long as it is available for threat evaluation - refer to Procedure PS-03-01-216: “Threat Identification and Risk Assessment.”

2.10.2 The Identified Site Information Sheet is a manual entry data form for use by field verification personnel. These forms are electronically scanned into the Segment Plan. The paper copies will be kept in the Identified Site Folders for the life of the pipe (regardless of the HCA's active or inactive status).

2.10.3 The HCA Segment Plan is a file structure used to store electronic data affecting HCA segments. Each pipeline containing an HCA will have a segment plan for each individual HCA segment. The HCA Segment Plan folder is located on the Pipe_Assess drive.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR 192

3.2 Industry Practices

- ASME B31.8S (2001): Managing System Integrity of Gas Pipelines
- GRI-00/0189: A Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines
- OPS document TTO13 Final Report: Potential Impact Radius Formulae for Flammable Gases Other than Natural Gas (dated 6/23/05)

3.3 Related Procedures/Supporting Documents

- PS-03-01-105, HCA Identification Process
- PS-03-01-216, Threat Identification and Risk Assessment Procedure
- PS-03-01-220, Baseline Assessment Plan Procedure
- Book 1, O&M Manual, Procedure 219, Population Density and HCA Field Survey

3.4 Forms and Attachments

- Form PS8132, Identified Site Information Sheet

4.0 DEFINITIONS

- **Class Location:** An area that extends 220 yards on either side of the centerline of a segment of pipeline. Class location units are categorized as Class 1, Class 2, Class 3, and Class 4. Class 1 locations are more rural, Class 4 locations are more urban. Reference CFR 49, Part 192.5 for more details.

- **Geographical Information System (GIS):** A system of computer software, hardware, data and personnel to help manipulate, analyze, and present information that is tied to a geographical location.

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

- **Potential Impact Circle:** A circle with a radius equal to the Potential Impact Radius (PIR).

- **Segment:** a length of pipeline or part of the system that has unique characteristics in a specific geographic location.

1.0 PURPOSE

This procedure describes the processes for managing the various data and records generated as a result of implementation of the Company's Integrity Management Program (IMP). Certain data and records generated during the normal course of operating and maintaining the Company's natural gas pipeline systems that are also necessary for implementation of the Integrity Management Program are also included in the scope of this procedure.

2.0 PROCEDURE

2.1 General

The Company's primary computerized data management system for pipeline information is the Asset Inventory Database. The Asset Inventory Database is populated and maintained by Data Integrity. Data Integration, within the Pipeline Integrity organization, is responsible for IMP data management and storage. Data Integration is also responsible for capture and verification of new and historical pipeline data. Data Integration will act as a liaison to Data Integrity to ensure the Asset Inventory Database is accurate. Pipeline Integrity also utilizes other commercial programs to store, maintain, manipulate, and retrieve the IMP-related data (ProActive, DataView, Microsoft Office products, etc.).

The following Integrity Management Program (IMP) data processes are discussed in this procedure:

- Direct Assessment Data Management:
  - o External Corrosion Direct Assessment
  - o Internal Corrosion Direct Assessment
  - o Stress Corrosion Cracking Direct Assessment
- In-Line Inspection Data Management
- Internet Searches for Identified Site Information
- Identified Site Information Sheets

- Records Retention
- Historical Data Accuracy and Reliability

The following operations and maintenance data processes are discussed in this procedure:

- Sleeves, Pipe Replacement and New Pipe Installation
- Engineering Diagrams
- Mill Test Reports
- Pressure Test Reports
- Exposed Pipe Reports
- Leak Reports
- MAOP Changes

2.2 Direct Assessment Data Management

2.2.1 The Direct Assessment (DA) activities include data requirements outlined in:

- Procedure PS 03-01-232: “External Corrosion Direct Assessment”
- Procedure PS 03-01-238: “Dry Gas – Internal Corrosion Direct Assessment”
- Procedure PS 03-01-240: “Stress Corrosion Cracking Direct Assessment”

2.2.2 Data from the DA processes is compiled by Pipeline Integrity and finalized during post-assessment. The finalized data is transmitted to the Data Integration group.

Data Integration shall perform a quality review of the data generated during implementation of the DA processes and shall store the electronic data in the Segment Plan, and file any paper copies. Data Integration shall also transmit data, as appropriate, to data administrators in Pipeline Integrity for evaluation and to Data Integrity for input into the Asset Inventory Database.

Data Integration shall confirm any required data is entered into the Asset Inventory Database and shall provide notifications the data is complete. If incomplete data is found, notifications will be made to Pipeline Integrity, Project Services, or to Region Pipeline Operations – as appropriate.

2.3 In-Line Inspection Data Management

In-line inspections using smart pigs are performed on pipeline segments to determine the integrity of the pipeline in accordance with Procedure PS-03-03-244: “In-Line Inspection and Analysis”.

2.3.1 ILI Run Data

The ILI vendor generates a report containing data and information about the pig run. The data is reviewed by the Pipeline Integrity Engineer responsible for In-Line Inspections (ILI) and copies, one electronic (normally a CD) and one paper, are submitted to Data Integration for storage. The electronic copy (CD) will be stored with the paper copy in the ILI file cabinet. ILI data review will include a comparison with the Asset Inventory Database and any errors will be resolved through Data Integrity.

2.3.2 Inspection and Remediation

As pipe inspection and remediation work is completed, the data and information pertaining to the work (for example, dig data sheets, digital photos and repair records) is collected and transmitted to Data Integration for a data quality review and electronic storage.

2.3.3 ILI Final Data Storage

Final data (resolved data conflicts, repairs, and remediation) is entered into the Asset Inventory Database by Data Integrity and confirmed by Data Integration.

2.4 Internet Searches for Identified Site Information

Internet searches for possible identified sites will be conducted in accordance with Procedure PS-03-01-200: “HCA Segment Identification”. Procedure PS-03-01-200, Table 1, lists the internet search categories. Data Integration may choose to purchase some, or all, of this information when it is available and is economically feasible. Internet searches will never discover 100% of the structures causing HCAs. Information from the field teams will always be crucial to this effort.

2.5 Identified Site Information Sheets and Memo for Records

2.5.1 Identified Site Information Sheets

Identified Site Information Sheets (Form PS8132) are generated by field teams to capture data about specific structures, in accordance with O&M Book 1 and PS-03-03-100: “Population Density and HCA Field Survey”. The identified site sheets are submitted to Data Integration for review and HCA determination. Once an identified site sheet is generated, it will be stored by line folder in the identified site sheet folder file cabinet. MRT lines are segregated from CEGT lines; and lines with active HCAs are segregated from those without. Identified site sheets are not discarded, even if the structure changes use and no longer qualifies as an Identified Site. The updated information will be captured on the identified site sheet and it will be retained in the line folder.

2.5.2 Memo for Records

Memo For Records (MFRs) will be used to provide information on non-identified site structures which do not warrant identified site sheets but may cause concern or confusion. In addition, MFRs can be used to clarify Identified Site Information Sheets. MFRs may also serve as temporary identified site sheets until field teams can submit completed identified site sheets. Paper copies of MFRs will be located in the identified site sheet line folder.

2.6 Records Retention

The Company will maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of Subpart O.

- Information has a varying “shelf life”. Some information is required for the life of the pipeline, and other information may only be useful for a year or two. The term “life of the pipe” implies that the data will be stored for one year after the pipeline is either sold or becomes inactive due to retirement or abandonment. In cases involving litigation, the data will be stored until all litigation is resolved.

- Data will be retained in accordance with Company Record Retention Policies.

- Documents generated by IMP processes and procedures will be cataloged in the Pipeline Integrity Document Catalog. The Pipeline Integrity Document Catalog lists the various Pipeline Integrity IMP documents and their storage locations, both the hard copy and the electronic copy (if applicable).

At minimum, the Company will maintain the following records:

- A written integrity management program.

- Documents supporting the threat identification and risk assessment.

- A written baseline assessment plan.

- Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.

- Documents that demonstrate personnel have the required training.

- Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a

State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

2.7 Historical Data Accuracy and Reliability

The reliability and accuracy of historical data depends, to a large degree, on the source of the data. Some sources are highly accurate, others are merely unsubstantiated copies. The accuracy of the data must be considered prior to entry into the Asset Inventory Database.

2.8 Sleeves, Pipe Replacement and New Pipe Installation

Sleeves, pipe replacements and new pipe installations are a routine function of the operation and maintenance of the Company's pipeline systems. The installation of sleeves, pipe replacements and new pipe installations in covered segments result in the generation of data that is needed for implementation of the IMP. Some of the data includes, but is not limited to, AFE paperwork, engineering diagrams, mill test reports, radiography reports, and pressure test reports. Other data may be requested as required.

The Company's pipeline operations and maintenance is organized into regions. Each Region Office is responsible for all operations and maintenance activities for the pipeline facilities assigned to the Region.

2.8.1 Pipeline replacement and new installation projects are coordinated in each Region by a Project Leader. The Project Leader shall prepare a project document package for each completed project. This document package is commonly known as the "Pink Envelope". Project documentation is required by Department of Transportation regulations.

2.8.2 The process for creation and validation of the DOT Pink Envelope is found in Procedure PS-03-03-100: "Records Compliance: Operator Qualification and DOT Records".

2.8.3 In accordance with Step 12 in Procedure 03-03-100, the Administrator will scan the DOT Pink Envelope and send the electronic version (called the "ePE") to Pipeline Integrity. Data Integration shall specify a file name structure for the ePE file to the Administrator. An example follows:

Year.Line Name.beginning station number.ePE.AFE Number.
2005.KM-6.102+00.ePE.9723

The example shown is intended to work for the majority of ePE files. On occasion, a different file name structure may be required, and shall be specified to the Administrator by Data Integration.

NOTE:
For large projects, the Administrator may request assistance in scanning the documents from Data Integration.

2.8.4 The Administrator shall transmit the ePE file to Data Integration. Typically the transmittal shall be by e-mail; however, in some cases, the file may be too big and the file should be burned on one or more CDs and transmitted through the Company mail system.

2.8.5 In accordance with Procedure PS-03-03-100: “Records Compliance: Operator Qualification and DOT Records”, Data Integration shall conduct an accuracy check of all information contained in the ePE file, and shall work through the Administrator to resolve all errors with the Project Leader.

2.8.6 Data Integration shall store all ePEs in the ePE folder inside the Pipe_Assess folder. Pipeline Integrity will also load applicable ePEs into the HCA Segment Plan. Reference the Pipeline Integrity Document Catalog in Section 3.4.

2.9 Engineering Diagrams

Engineering diagrams, representing enhancements or additions to improve the operating efficiency of a pipeline system, are generated by the Region Drafter. Engineering diagrams are sent electronically to Data Integrity for input into the Asset Inventory Database.

2.10 Mill Test Reports

Company purchase orders for pipe and other materials purchased for enhancements and additions to the Company’s pipeline facilities include requirements for vendors to supply mill test reports, or mill certifications for the materials being purchased.

The Shreveport Purchasing group shall obtain copies of the invoice and Mill Test Reports from the pipe vendor and shall provide a copy to Data Integration. Typically, these copies will be electronic.

The Company maintains stock pipe that is stored in various locations primarily for use in repairing pipelines. Stored pipe (emergency pipe) will be labeled in accordance with Book 3, Engineering Standards, Specification 113: “Material Certification (Subpart B Materials)”. When pipe is issued from a warehouse for installation in the pipeline, Shreveport Purchasing shall be contacted by the Region to obtain copies of the mill test reports.

The Project Leader has primary responsibility for obtaining and including copies of Mill Test Reports in the Pink Envelope. Backup sources available to the Project Leader for obtaining Mill Test Reports are Purchasing (Shreveport) and Data Integration.

Additional Mill Test Report requirements are discussed in Book 3, Engineering Standards, Specification 113: “Material Certification (Subpart B Materials)”.

2.11 Pressure Test Reports

Pressure test reports for recent and future construction shall be included by the Project Leader in the Pink Envelope.

2.12 Exposed Pipe Reports

As part of routine operations and maintenance activities, Field Teams conduct surveillance patrols of the Company’s pipeline facilities. Occasionally, pipe that is normally covered is found to be exposed.

An Exposed Pipe Inspection Report is generated by the team and the report data is entered into the Company’s computerized Maintenance Management System (MMS). Pipeline Integrity can access these reports electronically as needed.

2.13 Leak Reports

Leaks are reported to and investigated by the Field Teams. Leaks may also be discovered during routine surveillance patrols by the teams.

The Region Office assesses the leak to determine whether the leak repair will require any modification to the pipeline, such as installing a sleeve or replacing a section of pipe. If a sleeve or pipe replacement is required, refer to paragraph 2.8.

Once the leak is investigated and corrected, data concerning the leak is entered into MMS. Pipeline Integrity can access these reports electronically as needed.

2.14 MAOP Changes

Changes in the Maximum Allowable Operating Pressure (MAOP) are made to improve the safety and operating efficiency of a pipeline. MAOP change requests will be submitted and processed in accordance with Process PS-03-04-105: “MAOP Review”.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- None

3.3 Related Procedures/Supporting Documents

- PS-03-01-200, HCA Segment Identification Procedure
- PS-03-01-232, External Corrosion Direct Assessment Procedure
- PS-03-01-238, Dry Gas - Internal Corrosion Direct Assessment Procedure
- PS-03-01-240, Stress Corrosion Cracking Direct Assessment Procedure

- PS-03-01-244, In-Line Inspection and Analysis Procedure
- PS-03-03-100, Population Density and HCA Field Survey Process
- PS-03-03-105, MAOP Review Process
- Book 1, Operations and Maintenance, Procedure 219, Population Density and HCA Field Survey
- Book 2, Manual of Construction Specifications, Procedure 47, Pipeline Pressure Testing
- Book 3, Engineering Standards, Specification 113, Material Certification (Subpart B Materials)

3.4 Forms and Attachments

- Identified Site Information Sheet, Form PS8132
- Pipeline Integrity Document Catalog

4.0 DEFINITIONS

- **Asset Inventory Database** – The Company's primary database for storing pipeline attribute data. The current tool to access the information inside the Asset Inventory Database is Pipeline Open Data Standard (PODS). Facility Manager is used to navigate inside of PODS.

- **High Consequence Area (HCA)** – As outlined in Subpart O, 192.903: 1) Any area containing 20 or more structures intended for human occupancy (SIHO) within the PIR. 2) Any area containing an identified site within the PIR.

- **Identified Site** – As outlined in Subpart O, 192.903:
  1) An outside area occupied by 20 or more people at least 50 days during a 12 month period.
  2) A building that is occupied by 20 or more people at least 5 days a week for 10 weeks out of a 12 month period.

3) A facility occupied by people who are confined, are of impaired mobility, or would be difficult to evacuate.

- **In-Line Inspection (ILI)** - The use of an instrumented tool to non-destructively inspect a pipeline for features.

- **Maximum Allowable Operating Pressure (MAOP)** - The maximum pressure at which a gas pipeline or segment of a pipeline may be operated. The MAOP is based on the type of pipe and pressure testing, as well as the class location.

- **Stress Corrosion Cracking (SCC)** - Cracking which results from stress induced corrosion.

- **Maintenance Management System (MMS)** – A scheduling tool to track maintenance requirements and completions for the pipeline. The current tool to access the information in MMS is Maximo.

1.0 PURPOSE

This procedure establishes the process for conducting a risk assessment of pipeline segments by analyzing available information about the integrity of a specific pipeline or pipeline segment and evaluating the consequences of a failure.

2.0 PROCEDURE

2.1 Risk Assessment Requirements

The analysis and integration of available information about the relative likelihood and consequence of failure for a specific pipeline or pipeline segment requires:

- Pipe attributes
- Information critical to determining the potential for and prevention of damage due to excavation
- Data gathered through previous risk assessments, inspections and surveys including the following:
  - In-Line Inspection and Analysis
  - Pressure Testing
  - Surveillance and patrols in accordance with Inspection of Right-of-Way
  - External Corrosion Control Program
  - Internal Corrosion Control Program
  - Outside Forces Damage Prevention
- Information about how a failure would affect a High Consequence Area (HCA).
- Data gathered through Incident Investigations.

The Company requires analysis and integration of pipeline data, performance of risk assessment and resulting decisions be made by a person qualified in accordance with Procedure PS-03-01-272: “IMP Personnel Qualification Requirements”.

The risk assessment process is utilized as a means to evaluate and to determine the types of adverse events or conditions that might impact pipeline integrity and the severity of the consequences that might occur following a failure. Having such a measure supports the integrity management process by providing a basis for ranking and scheduling affected HCA segments for further evaluation.

This analytical process involves:

- The integration of pipeline system design, construction, operating, maintenance, testing, inspection and other applicable information
- The application of a risk screening technique to identify the most significant risks
- Development of an effective and prioritized prevention, detection, and remediation program to address those risks

All risk assessment approaches have the following common components:

- They identify potential events or conditions that could threaten system integrity
- They evaluate likelihood of failure and consequences
- They permit risk ranking and identification of specific threats that primarily influence or drive the risk
- They lead to the identification of integrity assessment and/or remediation options
- They provide for a data feedback loop mechanism
- They provide structure and continuous updating for risk reassessments

The risk assessment process is a combination of the following components:

- Potential Pipeline Threat Identification affecting HCAs
- Data Gathering, Review and Integration
- Risk Assessment

2.2 Potential Pipeline Threat Identification affecting HCAs:

Risk assessment components address the identification of prospective threats to HCAs by considering the impact of a pipeline release. The Company will make a threat-by-threat analysis of the entire pipeline. This analysis requires identification and evaluation of the significance of threats to pipeline integrity. Procedure PS-03-01-200: "HCA Segment Identification" provides a complete explanation of the HCA segments identification process.

The Company shall identify and evaluate the major threat categories for each covered pipeline segment. The risk model will also be capable of evaluating all other threats that may be identified. Potential threats that the Company shall consider are listed in ASME B31.8S, Section 2.2, and include the following (major threat categories are identified with an asterisk):

- Time dependent threats
  - External corrosion*
  - Internal corrosion*
  - Stress corrosion cracking*
- Static or resident threats
  - Manufacturing related defects*
    - Defective pipe seam
    - Defective pipe
  - Welding/fabrication related defects*

    - Defective pipe girth weld
    - Defective fabrication weld
    - Wrinkle, bend, or buckle
    - Stripped threads, broken pipe, coupling failure
    - Equipment related defects*
    - Gasket o-ring failure
    - Control/relief equipment malfunction
    - Seal/pump packing failure
    - Miscellaneous

- Time independent threats
  - Third party/mechanical damage*
    - Damage inflicted by first, second, or third parties (instantaneous or immediate failure)
    - Previously damaged pipe (delayed failure)
    - Vandalism
  - Incorrect operations*
    - Incorrect operational procedure
  - Weather related and outside force*
    - Cold weather
    - Lightning

  - Heavy rains or floods
  - Earth movements

* Major threat category

Cyclic fatigue or other loading condition (such as ground movement, suspension bridge condition, etc.) that could lead to a failure of a deformation, including a dent or a gouge, or other defect in the covered pipe segment shall be evaluated. The results from the evaluation together with the criteria used to evaluate the significance of this threat or interaction of threats to the covered pipe segment shall be used to prioritize the integrity assessment.

2.3 Segment Specific Threat Considerations

All threats are considered to be present on all pipeline segments unless specific criteria are met that would lead to a conclusion that the threat is stable or not present on a segment specific basis.

The following three threats, High pH SCC, Near-Neutral pH SCC, and Cyclic Fatigue, are considered to be present on a specific segment if the stated criteria are met.

- High pH Stress Corrosion Cracking - If all of the following criteria are met for a segment under evaluation, the high pH SCC threat is considered to exist.

  – Maximum operating stress (MAOP/ 100%SMYS) > 60%
  – Coating type other than fusion bonded epoxy (FBE)
  – Distance from the start of the pipeline segment to the nearest upstream compressor station < 20 miles
  – Pipeline age greater than 10 years
  – Operating Temperature greater than 100^{o} F

- Near-Neutral pH Stress Corrosion Cracking - If all of the following criteria are met for a segment under evaluation, the near-neutral pH SCC threat is considered to exist.

  – Maximum operating stress (MAOP/ 100%SMYS) > 60%
  – Coating type other than fusion bonded epoxy (FBE)

– Pipeline age greater than 10 years

- Cyclic Fatigue - Each pipeline segment shall be evaluated to determine if cyclic fatigue is to be considered a significant threat to any HCA segment. If any one of the following conditions are met, the cyclic fatigue threat is considered to exist on the segment:

  – Dents - Pipeline systems which operate at greater than 50% SMYS and experience pressure cycles equal to 80% of the MAOP on a daily basis.

  – Pipeline segments which are known to contain buckles or wrinkle bends and contain loading conditions which are considered to be cyclical in nature.

  – Vortex shedding conditions which are found as a result of examination of water crossings or evaluation of newly discovered HCAs.

  – Any HCA which includes a compressor station and the design criteria is not suitable for pulsation or mechanical vibration.

NOTE:
Cyclic Fatigue conditions based on criteria and discussion in Final Report PR-302-03152, see Section 3.0: References.

The following Manufacturing and Construction threats shall be evaluated on each segment to determine the stability or instability of the threat based upon the stated criteria.

- Manufacturing Seam Related Failures - If the pipeline segment being evaluated contains lap welded, hammer welded, butt welded, low-frequency ERW, or flash-welded pipe, and the operating pressure on the segment has increased over the maximum operating pressure experienced during the five year period preceding the date of discovery of the HCA, then the threat of Manufacturing Seam Related Failures is considered to be unstable. If the segment contains the pipe characteristics listed, but the operating pressure on the segment has not increased over the maximum operating pressure experienced during the five year period preceding the date of discovery of the HCA the threat of Manufacturing Seam Related Failures is considered to be stable.

- Manufacturing Defects – If the pipeline segment being evaluated contains cast iron pipe, steel pipe greater than 50 years old, mechanically coupled pipelines, or pipelines joined by means of acetylene girth welds and the segment is subject to low temperatures or movement (such as land movement or removal of supporting backfill) the threat of Manufacturing Defects is considered to exist and be unstable. If the segment contains the pipe characteristics listed, but is not subject to low temperatures or movement, the threat of Manufacturing Defects is considered to be stable.

- Construction Defects - If the pipeline segment being evaluated is subject to the potential for outside forces, the threat of Construction is considered to be unstable.

The Company shall keep a record of all seam failures on covered and non covered segments that contain low frequency electric resistance welded (ERW) pipe, lap-welded pipe, or other pipe that satisfies the conditions specified in ASME B31.8S, Appendices A4.3 and A4.4. HCA segments shall be compared to segments which have experienced seam failures to determine if similar conditions exist within the HCA segment. Reports and documents related to the prior seam failures which define pipe characteristics and operating conditions related to the cause of the failure shall be used to determine the similar conditions to be evaluated within the HCA segment.

The Company shall keep a record of the maximum operating pressure experienced in the five years prior to the identification of an HCA segment which contains low frequency electric resistance welded (ERW) pipe, lap-welded pipe, or other pipe that satisfies the conditions specified in ASME B31.8S, Appendices A4.3 and A4.4. HCA segments which meet this criteria shall be evaluated to determine if the operating pressure has exceed the five year maximum operating pressure from the Company records.

2.4 Data Gathering, Review and Integration:

Risk assessment components involve the gathering of all pertinent data to characterize individual pipeline segments and the potential threats of a release to the HCAs. Data gathered shall be referenced to a common reference system such as station numbers, GPS coordinates, known pipe or terrain features, etc. This provides for accurate association of data elements from various sources to the appropriate pipeline segment, and is important to the integration of data from various inspection activities, such as inspection tool runs.

Information pertaining to the design, operation, maintenance, operating history, corrosion program, surveillance and specific failures and concerns is utilized. Sources include operating personnel, documentation and third party knowledge. The data sources shall be documented. Appendix A provides a list of the data elements that, at a minimum, shall be collected.

Through the analysis of the pertinent information, the Company identifies the locations with the greatest incident risk potential and implements prudent measures to reduce those risks on an ongoing basis.

Initial high level screening assessments utilize information readily available or generally believed true. Explicit data is not necessarily included due to the time frame allowed to complete the screening and establish the baseline assessment schedule.

As necessary, the Company conducts more robust risk assessments using more comprehensive data. New information and additional operating experience is incorporated into the risk assessment analysis, priorities adjusted based on the outcomes, and the Integrity Management Program (IMP) revised to reflect the current status of pipeline integrity management.

When data is missing or is questionable, conservative assumptions shall be used when performing the risk assessment or alternatively the pipe segment shall be prioritized to a higher level. For missing or questionable data, default values shall be used. The default values shall be documented and the reason for their selection shall also be documented. Efforts shall be taken to replace missing or questionable data with reliable, accurate data. These efforts may include additional field surveys or inspections to obtain the data. Missing or questionable data shall be identified in the Missing Data Plan as identified in Process PS-03-01-115, Section 7(d).

In performing this data gathering and integration, the Company satisfies the requirements in ASME B31.8S.

2.5 Risk Assessment:

The Company conducts a risk assessment on each covered segment that follows Section 5, Risk Assessment, in ASME B31.8S. The Company will conduct risk assessment once per calendar year and validate using the SME approach. The risk assessment will be performed according to process PS-03-01-115.

Through data integration the risk assessment process identifies the threats potentially leading to a pipeline failure. The output of the risk assessment identifies the nature and location of the most significant anticipated risks, thereby allowing identified HCA segments to be risk ranked and scheduled for assessment accordingly. As additional pertinent data (for example, results of an integrity assessment or to account for mitigative actions) becomes available, the risk assessment is updated at least annually to determine the effects, if any, on HCA segment rankings and subsequent assessment schedules and the appropriate IMP sections are revised as necessary.

When and where applicable, special consideration shall be given to any plastic transmission pipe in HCAs when assessing risk, including gathering and integration of any special data and evaluation of potential unique threats or added consideration for particular types of threats.

When assessing risk, covered pipeline segments meeting the following conditions shall be given special consideration. Typically, special considerations consist of assigning higher risk values.

- Segments that contain low frequency electric resistance welded (ERW) pipe, lap-welded pipe, or other pipe that satisfies the conditions specified in ASME B31.8S, Appendices A4.3 and A4.4, and any covered or non covered segment in the pipeline system with such pipe that has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the five years preceding the date of discovery of the HCA.

- Covered segments that have manufacturing or construction defects (including seam defects) where any of the following changes occurred in the covered segment:

- Operating pressure increases above the maximum operating pressure experienced during the five years preceding identification of the HCA
  - For lines without a previous Subpart J hydrotest, the Company will maintain a list of the maximum operating pressures experienced during the five year period preceding the date the HCA was identified.
  - For lines without a previous Subpart J hydrotest, the Company will gather the maximum operating pressure data each year after the HCA has been identified and compare it to the list containing the data for the five year period preceding the date the HCA was identified.
  - This operation will be performed annually by the Sr. Pipeline Integrity Engineer. The list will be forwarded to Data Management for record retention.

- MAOP increases
  - For lines without a previous Subpart J hydrotest, the Company will gather MAOP data each year and compare it to the list containing the same information for the previous year.
  - This operation will be performed annually by the Sr. Pipeline Integrity Engineer. The list will be forwarded to Data Management for record retention.

- Stresses leading to cyclic fatigue increase

The risk assessment shall consider the frequency and consequences of past events. This should include the subject pipeline system or a similar system but other industry data should be used where sufficient data is initially not available.

The risk assessment shall account for any corrective or risk mitigation action that has occurred previously.

2.6 Risk Assessment Process

The risk assessment provides a means to evaluate both the potential effect of different incident types and the likelihood that such events may occur. Having such a measure supports the integrity management process by providing a basis for ranking and scheduling affected HCA segments for further evaluation.

Important objectives of the risk assessment include:

- Prioritization of pipeline segments for scheduling integrity assessments and subsequent repair, preventive, or remediation actions.

- Assessment of the benefits obtained from preventive or remediation actions.

- Assessment of potential integrity impact from modified inspection intervals.

- Assessment of the use of, or need for, alternative inspection methodologies.

- More effective resource allocation.

2.7 Risk Assessment Model:

- For the initial and recurring risk assessment, the Company uses the Company's Risk Assessment Model as the basis for assessing the relative risks of each HCA segment.

- The model, an indexing risk assessment technique, utilizes a scoring system to determine the relative exposure of pipeline or pipeline segments within a system. The model employs a comprehensive set of pipeline data to evaluate the risk of the entire system. Numeric values correspond to conditions that may lead to pipeline failure.

- The model scores the pipeline or pipeline segments using a detailed itemization and weighting of foreseeable events that might impact pipeline integrity and lead to a leak condition. An example is shown in Appendix B.

- The score obtained from the model depicts the risk of an HCA segment when compared to another scored HCA segment allowing prioritization of assessments. Both likelihood and consequence are inherent within the resulting pipeline risk ranking.

- The risk assessment model can be used to perform "what-if" analyses by changing one or more of the model inputs or adding new inputs and observing changes in the results. This allows for exploring ways to reduce risk.

2.8 HCA Segments

A pipeline does not usually have constant hazard potential over the entire length. As a result, the pipeline must be segmented to properly perform a risk analysis, which enables evaluation of constant characteristics for each segment. The characteristics associated with the pipeline are categorized as:

- Attributes are fixed characteristics of the operating system (operating environment).

- Preventions are actions taken by the Company that affect the occurrence of a potential hazard (actions taken in response to the environment).

The model considers both attributes and preventions; therefore, pipeline segmentation shall be done in such a way to ensure the evaluation of attributes and preventions within each segment remains relatively constant.

2.9 Validation

Validation of the risk assessment results is an important and ongoing process assuring the methods used have produced reasonable results consistent across the Company operated pipelines and with other operator experience. The validation is performed by the Manager of Pipeline Integrity and, at his option, by various subject matter experts as applicable. The validation is basically a review to determine whether the results are as expected and within the bounds of reasonableness. Additionally, spot inspections in the field and evaluations of low- and high-risk pipeline segments may be performed to validate the model is correctly characterizing the risks. When the Company locates sufficient additional objective data to affect the outcome and corresponding rankings, the risk assessment and associated schedules and procedures are modified to reflect current data. Additional objective data can include information from pipeline maintenance or other activities sufficient to identify inaccuracies in the characterization of risk for the pipeline segment or other similar segments.

2.10 Documented Changes

Any changes made to the Risk Assessment methodology will be documented in a Risk Assessment Change Log. Changes that may be included are:

- Date
- Description of change
- Who made change
- Reason for change (e.g.; equation modification, add/remove data fields, data presentation, interface for integration changes, database re-population, etc.)
- Data changes for specific pipeline segments are not required to be in change log
- Reference to relevant supporting documents to the change

All documentation to support any of the above changes will be kept in a change folder in a central location available to the Pipeline Integrity group.

Before any of the above changes are made, a backup of the risk model data output shall be made and archived in a central location available to the Pipeline Integrity group and documented in the change log.

Annually, the risk model database shall be backed up and documented on the change log, including location of backup.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S

- "Basics of Metal Fatigue in Natural Gas Pipeline Systems - A Primer for Gas Pipeline Operators," Final Report PR-302-03152, by M. J. Rosenfeld, PE, and Dr. J. F. Keifner, PE

3.3 Related Procedures/Supporting Documents

- PS-03-01-001, Integrity Management Program
- PS-03-01-115, Risk Assessment Process
- PS-03-01-200, HCA Segment Identification Procedure
- PS-03-01-272, IMP Personnel Qualification Requirements Procedure

3.4 Forms and Attachments

- Appendix A: Data Elements
- Appendix B: Risk Assessment Model

4.0 DEFINITIONS

- **ASME B31G** - Supplement to ASME Code for Pressure Piping for the purpose of providing guideline information (criterion) for measuring and determining the remaining strength of corroded pipelines.
- **ERW** - Electric Resistance Weld.
- **Global Positioning System (GPS)** - A system used to identify the latitude and longitude of locations using GPS satellites.
- **HCA Affect** - The length of pipeline that intersects or tangentially touches a HCA or affects a HCA through a transport process.
- **Maximum Allowable Operating Pressure (MAOP)** - The maximum pressure at which a gas pipeline or segment of a pipeline may be operated. Based on type of pipe and pressure testing.

APPENDIX A

Data Elements

Source: ASME B31.8S, Section 4.2.1, Table 1

1) Attribute Data
- Pipe wall thickness
- Diameter
- Seam type and joint factor
- Manufacturer
- Manufacturing date
- Material properties
- Equipment properties

2) Construction
- Year of installation
- Bending method
- Joined method, process, inspection results
- Depth of cover
- Crossings/casings
- Pressure test
- Field coating methods
- Soil, backfill
- Inspection reports
- Cathodic protection installed
- Coating type

3) Operational
- Gas quality
- Flow rate
- Normal maximum and minimum operating pressures
- Leak/failure history
- Coating condition
- Cathodic protection system performance
- Pipe wall temperature
- Pipe inspection reports
- External/internal corrosion monitoring
- Pressure fluctuations
- Regulator/relief performance

3) Operational (cont'd)
- Encroachments
- Repairs
- Vandalism
- External forces

4) Inspection
- Pressure tests
- In-line inspections
- Geometry tool inspections
- Bell hole inspections
- Cathodic protection inspections (Close Interval Survey)
- Coating condition inspections (Direct Current Voltage Gradient Survey)
- Audits and reviews

APPENDIX B

Risk Assessment Model

1.0 Risk Assessment Approach

1.1 The Company's risk assessment ranking model utilizes the relative ranking approach that compares risk scores of pipe segments to other segment scores within the same model.

2.0 Pipe Segmentation

2.1 The Company's pipeline system is segmented dynamically within the risk model based upon changes in selected risk attributes.

3.0 Threats Evaluated

3.1 Threats are grouped into nine threat categories per ASME B31.8S. The threats and the weight each threat carries in the evaluation of overall risk for a segment are shown below:

THREAT CATEGORIES		
TYPE	CATEGORY	WEIGHT {Current}
Time Dep	External Corrosion	15%
Time Dep	Internal Corrosion	14%
Time Dep	Stress Corrosion Cracking	10%
Static	Manufacturing	14%
Static	Construction/fabrication	10%
Static	Equipment	7%
Time Ind	Third Party Damage	15%
Time Ind	Incorrect Operations	6%
Time Ind	Weather and Outside Force	9%
	TOTAL	100%

TYPE:
Time Dep = Time Dependent Threat
Time Ind = Time Independent Threat
Static = Static Threat

Variable Type Description	
Data Type	Description
Dictionary	Listing of Values (e.g., Bare, Coated)
Range	Bracketed values (e.g., 0-10, 10-20)
Linear	Straight line interpolation, with values outside range receiving last highest/lowest value.

4.0 Factors Considered for Evaluation of the Threats

4.1 Numerous data elements are used in the evaluation of each of the nine threat categories listed above. The minimum data elements evaluated are derived from ASME B31.8S Non Mandatory Appendix A

4.2 The data elements used in the evaluation of the threats are shown on the attached tables. Each data element is evaluated independently and is provided a weighting score for how much weight it will carry in the evaluation of the threat. The sum of the weightings must equal 100%.

4.3 Each data element is categorized as either a Dictionary, Range or Linear variable. The higher the risk value, the greater the risk.

- Dictionary Variable – A look-up table provides the risk value that is assigned to each possible data value.

- Range Variable – A look-up table for ranges of values provides the risk value that will be assigned to elements which fall within a given range.

- Linear Variable – Risk values are assigned based upon a linear interpolation between a minimum and maximum value relative to the data value range. When data values fall outside the data value range, the data is assigned either the maximum or minimum risk value.

4.4 Default values are assigned within the risk model application and are only used when there is no supporting data available from the facilities database. The list of data elements and their default values are included in Section 8.1 of this Appendix.

Default values are chosen based upon conservative assumptions and reflect the values of other similar segments in the operator's pipeline system. Default values fall within one of three categories.

A. Missing or unknown data is evaluated as worst case – Data elements in this category are assigned default values of 1.0 or the highest possible risk. Data elements of this type include items such as whether or not a pressure test has been performed on the pipeline segment and date of last assessment. For these data elements, conclusive evidence of the data validity is required in order to assume less than worst case risk values.

B. Missing or unknown data is evaluated as accurate – Data elements in this category are assigned default values of 0.0 or the lowest possible risk. These data elements are generally considered point events such as leaks, equipment locations, and road crossings. The absence of data is considered to mean that no events have occurred or the condition is not present, i.e., the absence of data is correct.

C. Missing or unknown data is evaluated with a conservative value – Data elements in the category are assigned default values of 0.49, or middle risk. The use of a value of 0.49 for unknown data meets the intent of ASME B31.8S which states that assumptions shall be used which conservatively reflect the values of other segments on the operator's pipeline system. The use of middle risk values causes segments which have unknown or missing data to be driven toward middle risk and data elements on the same segment which known risk values are applied to either elevate or reduce the overall segment risk score.

It is the underlying philosophy of the risk assessment model that unknown or missing data should not automatically drive a segment to high risk for the purposes of assessment scheduling. It is the intent of the model to determine a risk based assessment schedule whereby high risk segments are assessed early within the baseline assessment schedule and low risk segments are assessed later in the baseline assessment schedule. By evaluating missing or unknown data as middle risk, the intent of using conservative assumptions is met and the data which is known, whether it be high or low risk in nature, will determine if the segment should be considered high or low risk.

This methodology of evaluating missing or unknown data is exclusive to the risk model and does not apply to any special evaluations required per SubPart O, such as 192.917 (e)(4). In these cases, if seam type were unknown, it would be considered to be LF-ERW until conclusive evidence could be contained to determine it was not LF-ERW.

5.0 Threat Likelihood (Probability)

5.1 Each segment is evaluated based upon the above model to determine a raw threat score between 0 and 100 for each of the nine threats.

5.2 The overall threat score is calculated as follows:

Total Likelihood = Σ (Normalized Threat Score) X (Threat Weight)

6.0 Consequence

6.1 The consequence value is determined by evaluating the following risk variables:

- Whether or not the segment is an HCA,
- The class location (population density) of the segment,
- The expected failure mode of the segment (leak vs. rupture), and
- The ratio of the length of the HCA to the PIR of the segment (do multiple identified sites exist).

Consequence values are determined using the following equation:

Consequence = (0.35 X Conseq_Population) + (0.35 X conseq_SMYS) + (0.1 X conseq_PIRLengthRatio) + (0.2 X Conseq_Class) = 0.49 (default value)

7.0 Total Risk

7.1 Total Risk is Calculated by the following formula:

Total Risk = Total Likelihood x Consequence

8.0 Attribute Maps

8.1 Following are nine tables showing the risk value index for attributes associated with various data elements for each of the nine major threats.

ACTIVE MODEL INFORMATION

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
Model documentation generated on 8/3/2005 10:39:10 AM by CEIP
Documentation output from RiskCalculator(tm) James W. Sewall Company

Model ID	Model Name	Version	Description	Last Edited On	Last Edited By	Consequence Variable
31	2005 Risk Assessment	1.0.0.20	Starting version number	8/3/2005 10:34	CEIP	Consequence

ALL DEFINED RISK ATTRIBUTES

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
Model documentation generated on 8/3/2005 10:39:10 AM by CEIP
Documentation output from RiskCalculator(tm) James W. Sewall Company

Item No.	Attribute Name	Description	Facilities View
1	AuditFrequency		AuditFrequency
2	BellholeCoating		BellholeCoating
3	BellholeInspections		BellholeInspections
4	BellholeRepair		BellholeRepair
5	CasedHCARoadCrossings		CasedHCARoadCrossings
6	ClassLocation		ClassLocation
7	ClassLocationSegmentation		ClassLocationSegmentation
8	CO2Exceptions		CO2Exceptions
9	CO2H2OExceptions		CO2H2OExceptions
10	CO2H2OExceptions_Line		CO2H2OExceptions_Line
11	Coating		Coating
12	CoatingCondition		CoatingCondition
13	ConsequencePIR		ConsequencePIR
14	ConsequencePopulation		ConsequencePopulation
15	ConsequenceSMYS		ConsequenceSMYS
16	CoupledPipe		CoupledPipe
17	CouponsPresentLines		CouponsPresentLines
18	Diameter		Diameter
19	DistanceCompressor		DistanceCompressor
20	EarthquakeZone		EarthquakeZone
21	ECAssessments		ECAssessments
22	EquipmentCount		EquipmentCount
23	ExposedPipe		ExposedPipe
24	ForeignLineCrossings		ForeignLineCrossings
25	H2OExceptions		H2OExceptions
26	H2OExceptions_Line		H2OExceptions_Line
27	H2SExceptions		H2SExceptions
28	H2SH2OExceptions		H2SH2OExceptions
29	H2SH2OExceptions_Line		H2SH2OExceptions_Line
30	HCA		HCA
31	ICAssessments		ICAssessments
32	InstallDate		InstallDate
33	InternalInspections		InternalInspections
34	JointType		JointType
35	LeakConstruction		LeakConstruction

Item No.	Attribute Name	Description	Facilities View
36	LeakConstruction_Line		LeakConstruction_Line
37	LeakConstruction_Series		LeakConstruction_Series
38	LeakConstructionBuffer		LeakConstructionBuffer
39	LeakEquipment		LeakEquipment
40	LeakEquipment_Line		LeakEquipment_Line
41	LeakEquipmentBuffer		LeakEquipmentBuffer
42	LeakExternalCorrosion		LeakExternalCorrosion
43	LeakExternalCorrosion_Lin		LeakExternalCorrosion_Line
44	LeakExternalCorrosionBuff		LeakExternalCorrosionBuffer
45	LeakIncorrectOperations		LeakIncorrectOperations
46	LeakIncorrectOperations_L		LeakIncorrectOperations_Line
47	LeakIncorrectOperationsBu		LeakIncorrectOperationsBuffer
48	LeakInternalCorrosion		LeakInternalCorrosion
49	LeakInternalCorrosion_Lin		LeakInternalCorrosion_Line
50	LeakInternalCorrosionBuff		LeakInternalCorrosionBuffer
51	LeakManufacturing		LeakManufacturing
52	LeakManufacturing_Line		LeakManufacturing_Line
53	LeakManufacturing_Series		LeakManufacturing_Series
54	LeakManufacturingBuffer		LeakManufacturingBuffer
55	LeakOtherBuffer		LeakOtherBuffer
56	LeakSCC		LeakSCC
57	LeakSCC_Line		LeakSCC_Line
58	LeakSCCBuffer		LeakSCCBuffer
59	LeakTPD		LeakTPD
60	LeakTPD_Line		LeakTPD_Line
61	LeakTPDBuffer		LeakTPDBuffer
62	LeakWeather		LeakWeather
63	LeakWeather_Line		LeakWeather_Line
64	LeakWeatherBuffer		LeakWeatherBuffer
65	ManufacturingMethod		ManufacturingMethod
66	MAOP		MAOP
67	MeetsCriteria		MeetsCriteria
68	MeterTesting_Series		MeterTesting_Series
69	MeterTestingFrequency		MeterTestingFrequency
70	OtherCorrosion		OtherCorrosion

Item No.	Attribute Name	Description	Facilities View
71	OverheadPower		OverheadPower
72	PatrolFrequency		PatrolFrequency
73	PipeAge		PipeAge
74	PipeMaterial		PipeMaterial
75	PIRLengthRatio		PIRLengthRatio
76	PressureTest		PressureTest
77	PressureTestDate		PressureTestDate
78	PressureTestPressure		PressureTestPressure
79	PreviousILI		PreviousILI
80	ProcedureReview		ProcedureReview
81	ProtectionCriteria		ProtectionCriteria
82	RailroadUncased		RailroadUncased
83	RoadCrossings		RoadCrossings
84	SCCAssessments		SCCAssessments
85	SCCSegmentation		SCCSegmentation
86	SeamType		SeamType
87	ServiceType		ServiceType
88	SevereCorrosion		SevereCorrosion
89	SMYS		SMYS
90	SoilCorrosivity		SoilCorrosivity
91	SoilStability		SoilStability
92	SoilType		SoilType
93	TeamNumber		TeamNumber
94	Temperature		Temperature
95	TerrainType		TerrainType
96	TPDAssessments		TPDAssessments
97	TPDLocations		TPDLocations
98	WallThickness		WallThickness
99	WetDryService		WetDryService
100	WrinkleBends		WrinkleBends

ALL DATA FILTERS BY ATTRIBUTE

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
Model documentation generated on 8/3/2005 10:39:10 AM by CEIP
Documentation output from RiskCalculator(tm) James W. Sewall Company

Item No.	Filter Name	Description	Filter Type	Attribute Name
1	AuditFrequency		DICTIONARY	AuditFrequency
2	BellholeCoating		DICTIONARY	BellholeCoating
3	BellholeInspections		LINEAR	BellholeInspections
4	BellholeRepair		LINEAR	BellholeRepair
5	CasedHCARoadCrossings		LINEAR	CasedHCARoadCrossings
6	ClassLocation		DICTIONARY	ClassLocation
7	CO2Exceptions		LINEAR	CO2Exceptions
8	CO2H2OExceptions		LINEAR	CO2H2OExceptions
9	CO2H2OExceptions_Line		LINEAR	CO2H2OExceptions_Line
10	Coating		DICTIONARY	Coating
11	CoatingCondition		DICTIONARY	CoatingCondition
12	ConsequencePopulation		DICTIONARY	ConsequencePopulation
13	CoupledPipe		DICTIONARY	CoupledPipe
14	CouponsPresentLines		LINEAR	CouponsPresentLines
15	Diameter		LINEAR	Diameter
16	DistanceCompressor		LINEAR	DistanceCompressor
17	EarthquakeZone		DICTIONARY	EarthquakeZone
18	ECAssessments		LINEAR	ECAssessments
19	EquipmentCount		LINEAR	EquipmentCount
20	ExposedPipe		LINEAR	ExposedPipe
21	ForeignLineCrossings		LINEAR	ForeignLineCrossings
22	H2OExceptions		LINEAR	H2OExceptions
23	H2OExceptions_Line		LINEAR	H2OExceptions_Line
24	H2SExceptions		LINEAR	H2SExceptions
25	H2SH2OExceptions		LINEAR	H2SH2OExceptions
26	H2SH2OExceptions_Line		LINEAR	H2SH2OExceptions_Line
27	ICAssessments		LINEAR	ICAssessments
28	InstallDate		RANGE	InstallDate
29	InternalInspections		LINEAR	InternalInspections
30	JointType		DICTIONARY	JointType
31	LeakConstruction_Line		LINEAR	LeakConstruction_Line
32	LeakConstruction_Series		LINEAR	LeakConstruction_Series
33	LeakConstructionBuffer		LINEAR	LeakConstructionBuffer
34	LeakEquipment_Line		LINEAR	LeakEquipment_Line
35	LeakEquipmentBuffer		LINEAR	LeakEquipmentBuffer

Item No.	Filter Name	Description	Filter Type	Attribute Name
36	LeakExternalCorrosion_Lin		LINEAR	LeakExternalCorrosion_Lin
37	LeakExternalCorrosionBuff		LINEAR	LeakExternalCorrosionBuff
38	LeakIncorrectOperations_L		LINEAR	LeakIncorrectOperations_L
39	LeakIncorrectOperationsBu		LINEAR	LeakIncorrectOperationsBu
40	LeakInternalCorrosion_Lin		LINEAR	LeakInternalCorrosion_Lin
41	LeakInternalCorrosionBuff		LINEAR	LeakInternalCorrosionBuff
42	LeakManufacturing_Line		LINEAR	LeakManufacturing_Line
43	LeakManufacturing_Series		LINEAR	LeakManufacturing_Series
44	LeakManufacturingBuffer		LINEAR	LeakManufacturingBuffer
45	LeakSCC_Line		LINEAR	LeakSCC_Line
46	LeakSCCBuffer		LINEAR	LeakSCCBuffer
47	LeakTPD_Line		LINEAR	LeakTPD_Line
48	LeakTPDBuffer		LINEAR	LeakTPDBuffer
49	LeakWeather_Line		LINEAR	LeakWeather_Line
50	LeakWeatherBuffer		LINEAR	LeakWeatherBuffer
51	ManufacturingMethod		DICTIONARY	ManufacturingMethod
52	MeetsCriteria		DICTIONARY	MeetsCriteria
53	MeterTesting_Series		DICTIONARY	MeterTesting_Series
54	OtherCorrosion		LINEAR	OtherCorrosion
55	OverheadPower		LINEAR	OverheadPower
56	PatrolFrequency		DICTIONARY	PatrolFrequency
57	PipeAge		LINEAR	PipeAge
58	scc_PipeAge		LINEAR	PipeAge
59	PipeMaterial		DICTIONARY	PipeMaterial
60	PIRLengthRatio		RANGE	PIRLengthRatio
61	PressureTest		DICTIONARY	PressureTest
62	PreviousILI		LINEAR	PreviousILI
63	ProcedureReview		DICTIONARY	ProcedureReview
64	ProtectionCriteria		DICTIONARY	ProtectionCriteria
65	RailroadUncased		LINEAR	RailroadUncased
66	RoadCrossings		LINEAR	RoadCrossings
67	SCCAssessments		LINEAR	SCCAssessments
68	SCCSegmentation		LINEAR	SCCSegmentation
69	SeamType		DICTIONARY	SeamType
70	ServiceType		DICTIONARY	ServiceType
71	SevereCorrosion		LINEAR	SevereCorrosion
72	SMYS		LINEAR	SMYS
73	SCC_SMYS		LINEAR	SMYS
74	conseq_SMYS		LINEAR	SMYS
75	SoilCorrosivity		DICTIONARY	SoilCorrosivity
76	SoilStability		DICTIONARY	SoilStability
77	SoilType		DICTIONARY	SoilType
78	TeamNumber		DICTIONARY	TeamNumber
79	Temperature		LINEAR	Temperature
80	TerrainType		DICTIONARY	TerrainType
81	TPDAssessments		LINEAR	TPDAssessments
82	TPDLocations		DICTIONARY	TPDLocations
83	WallThickness		LINEAR	WallThickness
84	WetDryService		DICTIONARY	WetDryService
85	WrinkleBends		DICTIONARY	WrinkleBends

DICTIONARY DATA FILTERS

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
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Item No.	Filter Name	Data Value	Risk Value
1	AuditFrequency	12	0.1
2	AuditFrequency	24	0.5
3	AuditFrequency	36	1
4	AuditFrequency	never	1
5	AuditFrequency	unknown	0.5
6	BellholeCoating	ASPHALT OR TAR NO WRAPPER	0.7
7	BellholeCoating	ASPHALT OR TAR WRAPPER	0.6
8	BellholeCoating	BLANK AT CONVERSION	0.5
9	BellholeCoating	EPOXY	0.15
10	BellholeCoating	MASTIC	0.7
11	BellholeCoating	NONE (BARE)	1
12	BellholeCoating	OTHER	0.5
13	BellholeCoating	PLASTIC TAPE	0.9
14	BellholeCoating	TGF3	0.5
15	BellholeCoating	WAX NO WRAPPER	0.4
16	BellholeCoating	WAX WITH WRAPPER	0.3
17	BellholeCoating	WAX WRAPPER	0.3
18	ClassLocation	Class 1	0.1
19	ClassLocation	Class 2	0.4
20	ClassLocation	Class 3	0.75
21	ClassLocation	Class 4	1
22	ClassLocation	None	0.5
23	ClassLocation	Unknown	0.5
24	Coating	AGF - 7	0.95
25	Coating	AGM - 7	0.95
26	Coating	BARE	1
27	Coating	CT_EPOXY	0.3
28	Coating	CTE - B	0.4
29	Coating	EPOXY	0.15
30	Coating	FBE	0.1
31	Coating	FBE-W/CONC	0.1
32	Coating	POLY_CONC	0.4
33	Coating	TG - 3	0.5
34	Coating	TGF - 2	0.55
35	Coating	TGF - 3	0.5

Item No.	Filter Name	Data Value	Risk Value
36	Coating	TGF - 7	0.45
37	Coating	UNKNOWN	0.5
38	CoatingCondition	F	0.6
39	CoatingCondition	G	0.1
40	CoatingCondition	P	1
41	ConsequencePopula	Class 1	0.3
42	ConsequencePopula	Class 1 Crossing	0.3
43	ConsequencePopula	Class 2	0.5
44	ConsequencePopula	Class 2 Crossing	0.5
45	ConsequencePopula	Class 3	0.75
46	ConsequencePopula	Class 3 Crossing	0.75
47	ConsequencePopula	Class 4	0.9
48	ConsequencePopula	Class 4 Crossing	0.9
49	ConsequencePopula	HCA	1
50	ConsequencePopula	Unknown	0.49
51	CoupledPipe	COUPLED	1
52	CoupledPipe	UNKNOWN	1
53	EarthquakeZone	0	0
54	EarthquakeZone	1	0.1
55	EarthquakeZone	2	0.3
56	EarthquakeZone	3	0.7
57	EarthquakeZone	4	1
58	EarthquakeZone	no	0
59	EarthquakeZone	unknown	0.5
60	EarthquakeZone	yes	1
61	JointType	COUPLED	1
62	JointType	ELCWELD	0
63	JointType	SCREWED	0.8
64	JointType	UNKNOWN	0.5
65	MeetsCriteria	BELOW CRITERIA	1
66	MeetsCriteria	MEETS CRITERIA	0
67	MeterTesting_Series	Bi-Weekly	0.35
68	MeterTesting_Series	Monthly	0.6
69	MeterTesting_Series	Not Scheduled	0.8
70	MeterTesting_Series	Unknown	0.5
71	MeterTesting_Series	Weekly	0.1
72	PatrolFrequency	12	1
73	PatrolFrequency	4	0.1
74	PatrolFrequency	6	0.5
75	PipeMaterial	PLASTIC	0.5

Item No.	Filter Name	Data Value	Risk Value
76	PipeMaterial	STEEL	0
77	PipeMaterial	UNKNOWN	0.5
78	PressureTest	0	1
79	PressureTest	1	0
80	ProcedureReview	12	0.3
81	ProcedureReview	6	0.1
82	ProcedureReview	More than 12	0.7
83	ProcedureReview	Never	1
84	ProcedureReview	Unknown	0.5
85	ProtectionCriteria	N	1
86	ProtectionCriteria	Unknown	0.5
87	ProtectionCriteria	Y	0
88	SeamType	BUTT	0.2
89	SeamType	DSAW	0.2
90	SeamType	EARLY SMITH WELD	1
91	SeamType	ERW	0.1
92	SeamType	EW	0.1
93	SeamType	FURNACELAP	0.7
94	SeamType	LF-ERW	1
95	SeamType	NO METHOD	0.5
96	SeamType	OTHER	0.5
97	SeamType	SAW	0.4
98	SeamType	SMITH WELD	0.8
99	SeamType	SMLS	0
100	SeamType	SPIRAL	0.55
101	SeamType	UNKNOWN	0.5
102	ServiceType	SOUR	1
103	ServiceType	SWEET	0
104	ServiceType	unknown	0.5
105	SoilCorrosivity	unknown	0.5
106	SoilStability	STABLE	0
107	SoilStability	UNKNOWN	0.5
108	SoilStability	UNSTABLE	1
109	SoilType	unknown	0.5
110	TeamNumber	671	0.05
111	TeamNumber	673	0.1
112	TeamNumber	674	0.15
113	TeamNumber	675	0.2
114	TeamNumber	676	0.25
115	TeamNumber	692	0.3

Item No.	Filter Name	Data Value	Risk Value
116	TeamNumber	693	0.35
117	TeamNumber	694	0.4
118	TeamNumber	711	0.45
119	TeamNumber	712	0.5
120	TeamNumber	713	0.55
121	TeamNumber	717	0.6
122	TeamNumber	718	0.65
123	TeamNumber	732	0.7
124	TeamNumber	733	0.75
125	TeamNumber	735	0.8
126	TeamNumber	737	0.85
127	TeamNumber	739	0.9
128	TeamNumber	741	0.91
129	TeamNumber	743	0.92
130	TeamNumber	747	0.93
131	TeamNumber	752	0.94
132	TeamNumber	753	0.95
133	TeamNumber	755	0.96
134	TeamNumber	758	0.97
135	TeamNumber	760	0.98
136	TerrainType	F	0.1
137	TerrainType	GH	0.4
138	TerrainType	H	0.7
139	TerrainType	M	1
140	TPDLocations	DENT, SCRATCH OR GOUGE	1
141	WetDryService	dry	0
142	WetDryService	unknown	0.5
143	WetDryService	wet	1
144	WrinkleBends	no	0
145	WrinkleBends	Unknown	0.5
146	WrinkleBends	yes	1

RANGE DATA FILTERS

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Item No.	Filter Name	Data Low Value	Data High Value	Risk Value
1	InstallDate	0	1940	1
2	InstallDate	1940	1950	0.9
3	InstallDate	1950	1960	0.8
4	InstallDate	1960	1970	0.7
5	InstallDate	1970	1980	0.4
6	InstallDate	1980	1990	0.2
7	InstallDate	1990	2100	0.1
8	PIRLengthRatio	0	4.5	0.2
9	PIRLengthRatio	4.5	8.5	0.4
10	PIRLengthRatio	8.5	13	0.65
11	PIRLengthRatio	13	17	0.8
12	PIRLengthRatio	17	10000	1

LINEAR DATA FILTERS

Risk Model Name: 2005 Risk Assessment
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Description: Starting version number
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Item No.	Filter Name	Data Low Value	Data High Value	Risk Low Value	Risk High Value
1	BellholeInspections	0	4	1	0
2	BellholeRepair	0	4	0	1
3	CasedHCARoadCrossings	0	1	0	1
4	CO2Exceptions	0	20	0	1
5	CO2H2OExceptions	0	3	0	1
6	CO2H2OExceptions_Line	0	10	0	1
7	conseq_SMYS	20	40	0.2	1
8	CouponsPresentLines	0	1	1	0
9	DistanceCompressor	0	105600	1	0
10	ECAssessments	0	7	0	1
11	EquipmentCount	0	40	0	1
12	ExposedPipe	0	1	0	1
13	ForeignLineCrossings	0	3	0	1
14	H2OExceptions	0	10	0	1
15	H2OExceptions_Line	0	10	0	1
16	H2SExceptions	0	10	0	1
17	H2SH2OExceptions	0	3	0	1
18	H2SH2OExceptions_Line	0	5	0	1
19	ICAssessments	0	7	0	1
20	InternalInspections	0	4	1	0
21	LeakConstruction_Line	0	10	0	1
22	LeakConstruction_Series	0	1	0	1
23	LeakConstructionBuffer	0	3	0	1
24	LeakEquipment_Line	0	10	0	1
25	LeakEquipmentBuffer	0	3	0	1
26	LeakExternalCorrosion_Lin	0	40	0	1
27	LeakExternalCorrosionBuff	0	3	0	1
28	LeakIncorrectOperations_L	0	10	0	1
29	LeakIncorrectOperationsBu	0	3	0	1
30	LeakInternalCorrosion_Lin	0	5	0	1
31	LeakInternalCorrosionBuff	0	3	0	1
32	LeakManufacturing_Line	0	10	0	1
33	LeakManufacturing_Series	0	1	0	1
34	LeakManufacturingBuffer	0	3	0	1
35	LeakSCC_Line	0	5	0	1

Item No.	Filter Name	Data Low Value	Data High Value	Risk Low Value	Risk High Value
36	LeakSCCBuffer	0	3	0	1
37	LeakTPD_Line	0	5	0	1
38	LeakTPDBuffer	0	3	0	1
39	LeakWeather_Line	0	5	0	1
40	LeakWeatherBuffer	0	3	0	1
41	OtherCorrosion	0	5	0	1
42	OverheadPower	0	3	0	1
43	PipeAge	20	60	0	1
44	PreviousILI	0	1	1	0
45	RailroadUncased	0	2	0	1
46	RoadCrossings	0	10	0	1
47	scc_PipeAge	10	60	0	1
48	SCC_SMYS	60	72	0	1
49	SCCAssessments	0	7	0.25	1
50	SCCSegmentation	0	1	0	1
51	SevereCorrosion	0	3	0	1
52	SMYS	20	60	0	1
53	Temperature	100	200	0	1
54	TPDAssessments	0	7	0	1
55	WallThickness	0.5	0.125	0	1

THREAT CATEGORY DEFINITIONS

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Item No.	Threat Name	Description	Threat Weight
1	Construction	Construction	0.1
2	Equipment	Equipment	0.07
3	ExternalCorrosion	ExternalCorrosion	0.15
4	IncorrectOperations	Incorrect Operations	0.06
5	InternalCorrosion	Internal Corrosion	0.14
6	Manufacturing	Manufacturing	0.14
7	OtherInformation	Other Information for Sorting	0
8	StressCorrosionCracking	Stress CorrosionCracking	0.1
9	ThirdPartyDamage	Third Party Damage	0.15
10	Weather	Weather	0.09

RISK VARIABLES USED FOR THREAT CALCULATION

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Item No.	Threat Name	Variable Name	Variable Description	Variable Weight	Definition	Default Value
1	Construction	con_BellholeInspections		0	Count(BellholeInspections)	1
2	Construction	con_CoupledPipe		0	Value(CoupledPipe)	0
3	Construction	con_ExposedPipe		0	Count(ExposedPipe)	0
4	Construction	con_LeakConstruction_Line		0	Value(LeakConstruction_Line)	0
5	Construction	con_LeakConstructionBuffe		0	Count(LeakConstructionBuffer)	0
6	Construction	con_PipeMaterial		0	Value(PipeMaterial)	0.49
7	Construction	con_PressureTest		0	Value(PressureTest)	1
8	Construction	con_RailroadUncased		0	Count(RailroadUncased)	0
9	Construction	con_SoilStability		0	Value(SoilStability)	0.49
10	Construction	con_TerrainType		0	Value(TerrainType)	0.49
11	Construction	con_WrinkleBends		0	Value(WrinkleBends)	0.49
12	Construction	ConstructionThreat		100	if(con_PressureTest=0 & con_LeakCon_Series=0, 0, (0.14* con_BellholeInspections + 0.15* con_CoupledPipe + 0.08* con_ExposedPipe + 0.042* con_LeakConstruction_Line + 0.098* con_LeakConstructionBuffe + 0.10* con_PipeMaterial +0.14* con_PressureTest + 0.02*	0.49
13	Equipment	eq_EquipmentCount		60	Sum(EquipmentCount)	0
14	Equipment	eq_LeakEquipment_Line		12	Value(LeakEquipment_Line)	0
15	Equipment	eq_LeakEquipmentBuffer		28	Count(LeakEquipmentBuffer)	0

Item No.	Threat Name	Variable Name	Variable Description	Variable Weight	Definition	Default Value
16	ExternalCorrosion	ec_BellholeInspections		5	Count(BellholeInspections)	0
17	ExternalCorrosion	ec_BellholeRepair		3	Count(BellholeRepair)	0
18	ExternalCorrosion	ec_CoatingCondition		11	Value(CoatingCondition)	0.49
19	ExternalCorrosion	ec_Diameter		2	Value(Diameter)	0.49
20	ExternalCorrosion	ec_LeakEC_Line		3	Value(LeakExternalCorrosion_Lin)	0
21	ExternalCorrosion	ec_LeakECBuffer		7	Count(LeakExternalCorrosionBuff)	0
22	ExternalCorrosion	ec_MeetsCriteria		8	Value(MeetsCriteria)	0.49
23	ExternalCorrosion	ec_OtherCorrosion		2	Count(OtherCorrosion)	0
24	ExternalCorrosion	ec_OverheadPower		2	Count(OverheadPower)	0
25	ExternalCorrosion	ec_PipeAge		13	Value(PipeAge)	0.49
26	ExternalCorrosion	ec_PreviousILI		10	Value(PreviousILI)	1
27	ExternalCorrosion	ec_ProtectionCriteria		4	Value(ProtectionCriteria)	1
28	ExternalCorrosion	ec_SevereCorrosion		5	Count(SevereCorrosion)	0
29	ExternalCorrosion	ec_SMYS		4	Value(SMYS)	0.49
30	ExternalCorrosion	ec_SoilCorrosivity		5	Value(SoilCorrosivity)	0.49
31	ExternalCorrosion	ec_SoilType		3	Value(SoilType)	0.49
32	ExternalCorrosion	ec_WallThickness		4	Value(WallThickness)	0.49
33	ExternalCorrosion	ec_worstcoating		9	If(ec_BellholeCoating>ec_coating, ec_BellholdCoating, ec_coating)	0.5
34	IncorrectOperations	io_AuditFrequency		30	Value(AuditFrequency)	0.49
35	IncorrectOperations	io_LeakIO_Line		12	Value(LeakIncorrectOperations_L)	0
36	IncorrectOperations	io_LeakIOBuffer		28	Count(LeakIncorrectOperationsBu)	0
37	IncorrectOperations	io_ProcedureReview		30	Value(ProcedureReview)	0.49
38	InternalCorrosion	ic_CO2Exceptions		2	Count(CO2Exceptions)	0
39	InternalCorrosion	ic_CO2H2OExceptions		5	Count(CO2H2OExceptions)	0
40	InternalCorrosion	ic_CO2H2OExceptions_Line		2	Value(CO2H2OExceptions_Line)	0
41	InternalCorrosion	ic_CouponsPresentLines		2	Count(CouponsPresentLines)	1
42	InternalCorrosion	ic_Diameter		4	Value(Diameter)	0.49
43	InternalCorrosion	ic_H2OExceptions		4	Count(H2OExceptions)	0
44	InternalCorrosion	ic_H2OExceptions_Line		2	Value(H2OExceptions_Line)	0
45	InternalCorrosion	ic_H2SExceptions		3	Count(H2SExceptions)	0

Item No.	Threat Name	Variable Name	Variable Description	Variable Weight	Definition	Default Value
46	InternalCorrosion	ic_H2SH2OExceptions		5	Count(H2SH2OExceptions)	0
47	InternalCorrosion	ic_H2SH2OExceptions_Line		2	Value(H2SH2OExceptions_Line)	0
48	InternalCorrosion	ic_InternalInspections		8	Count(InternalInspections)	0
49	InternalCorrosion	ic_LeakIC_Line		4.5	Value(LeakInternalCorrosion_Lin)	0
50	InternalCorrosion	ic_LeakICBuffer		10.5	Count(LeakInternalCorrosionBuff)	0
51	InternalCorrosion	ic_MeterTesting_Series		8	Value(MeterTesting_Series)	1
52	InternalCorrosion	ic_PipeAge		10	Value(PipeAge)	0.49
53	InternalCorrosion	ic_PreviousILI		8	Value(PreviousILI)	1
54	InternalCorrosion	ic_ServiceType		2	Value(ServiceType)	0.49
55	InternalCorrosion	ic_SMYS		8	Value(SMYS)	0.49
56	InternalCorrosion	ic_TerrainType		4	Value(TerrainType)	0.49
57	InternalCorrosion	ic_WallThickness		4	Value(WallThickness)	0.49
58	InternalCorrosion	ic_WetDryService		2	Value(WetDryService)	0.49
59	Manufacturing	man_InstallDate		0	Value(InstallDate)	0.49
60	Manufacturing	man_JointType		0	Value(JointType)	0.49
61	Manufacturing	man_LeakManufacturing_Lin		0	Value(LeakManufacturing_Line)	0
62	Manufacturing	man_LeakManufBuffer		0	Count(LeakManufacturingBuffer)	0
63	Manufacturing	mfg_PipeMaterial		0	Value(PipeMaterial)	0.49
64	Manufacturing	mfg_PressureTest		0	Value(PressureTest)	1
65	Manufacturing	mfg_RailroadUncased		0	Count(RailroadUncased)	0
66	Manufacturing	mfg_SeamType		0	Value(SeamType)	0.49
67	Manufacturing	MFGThreat		100	if(mfg_PressureTest=0 & man_LeakManuf_Series=0, 0, (0.18* man_InstallDate + 0.12* man_JointType + 0.045* man_LeakManufacturing_Lin + 0.105* man_LeakManufBuffer + 0.16* mfg_PipeMaterial + 0.15* mfg_PressureTest + 0.03* mfg_RailroadUncased + 0.21* mfg_SeamT	0.49
68	OtherInformation	Conseq_Class		0	Value(ClassLocation)	0.49

Item No.	Threat Name	Variable Name	Variable Description	Variable Weight	Definition	Default Value
69	OtherInformation	conseq_PIRLengthRatio		0	Value(PIRLengthRatio)	0
70	OtherInformation	Conseq_Population		0	Value(ConsequencePopulation)	0.49
71	OtherInformation	consq_SMYS		0	Value(conseq_SMYS)	0.49
72	OtherInformation	ec_ECAssessments		0	DBMin(ECAssessments)	1
73	OtherInformation	ic_ICAssessments		0	DBMin(ICAssessments)	1
74	OtherInformation	SCC_Assessments		0	Value(SCCAssessments)	1
75	OtherInformation	Seg_CasedHCARoadCrossings		0	Value(CasedHCARoadCrossings)	0
76	OtherInformation	Seg_SCCSegmentation		0	Value(SCCSegmentation)	0
77	OtherInformation	Seg_TeamNumber		0	Value(TeamNumber)	0.499
78	StressCorrosionCracking	SCC		100	if (scc_coating=0.1 | scc_DistanceCompressor=0 | scc_stress=0,0,(0.10* scc_Age+0.16* scc_coating+0.10* scc_coatingcondition+0.12* scc_DistanceCompressor+0.03* scc_LeakSCC_Line+0.07* scc_LeakSCCBuffer+0.04* scc_pressuretest+0.19* scc_stress+0.19* scc_Tempe	0.5
79	StressCorrosionCracking	scc_Age		0	Value(PipeAge)	0.49
80	StressCorrosionCracking	scc_coating		0	Value(Coating)	0.49
81	StressCorrosionCracking	scc_coatingcondition		0	Value(CoatingCondition)	0.49
82	StressCorrosionCracking	scc_DistanceCompressor		0	Value(DistanceCompressor)	0
83	StressCorrosionCracking	scc_LeakSCC_Line		0	Value(LeakSCC_Line)	0
84	StressCorrosionCracking	scc_LeakSCCBuffer		0	Count(LeakSCCBuffer)	0
85	StressCorrosionCracking	scc_pressuretest		0	Value(PressureTest)	1
86	StressCorrosionCracking	scc_stress		0	Value(SCC_SMYS)	0.49
87	StressCorrosionCracking	scc_Temperature		0	Value(Temperature)	0
88	ThirdPartyDamage	tpd_BellholeInspections		14	Count(BellholeInspections)	1
89	ThirdPartyDamage	tpd_ClassLocation		14	Value(ClassLocation)	0.49
90	ThirdPartyDamage	tpd_ExposedPipe		5	Count(ExposedPipe)	0

Item No.	Threat Name	Variable Name	Variable Description	Variable Weight	Definition	Default Value
91	ThirdPartyDamage	tpd_ForeignLineCrossings		6	Count(ForeignLineCrossings)	0
92	ThirdPartyDamage	tpd_LeakTPD_Line		6	Value(LeakTPD_Line)	0
93	ThirdPartyDamage	tpd_LeakTPDBuffer		14	Count(LeakTPDBuffer)	0
94	ThirdPartyDamage	tpd_OverheadPower		5	Count(OverheadPower)	0
95	ThirdPartyDamage	tpd_PatrolFrequency		5	Value(PatrolFrequency)	0.49
96	ThirdPartyDamage	tpd_RailroadUncased		3	Count(RailroadUncased)	0
97	ThirdPartyDamage	tpd_RoadCrossings		6	Count(RoadCrossings)	0
98	ThirdPartyDamage	tpd_TPDAssessments		8	DBMin(TPDAssessments)	1
99	ThirdPartyDamage	tpd_TPDLocations		14	Value(TPDLocations)	0
100	Weather	ofg_EarthquakeZone		6	Value(EarthquakeZone)	0.49
101	Weather	ofg_jointtype		16	Value(JointType)	0.49
102	Weather	ofg_LeakWeather_Line		4.5	Value(LeakWeather_Line)	0
103	Weather	ofg_LeakWeatherBuffer		10.5	Count(LeakWeatherBuffer)	0
104	Weather	ofg_PipeAge		12	Value(PipeAge)	0.49
105	Weather	ofg_RailroadUncased		4	Count(RailroadUncased)	0
106	Weather	ofg_RoadCrossings		4	Count(RoadCrossings)	0
107	Weather	ofg_SMYS		17	Value(SMYS)	0.49
108	Weather	ofg_SoilStability		10	Value(SoilStability)	0.49
109	Weather	ofg_SoilType		8	Value(SoilType)	0.49
110	Weather	ofg_TerrainType		8	Value(TerrainType)	0.49

RISK VARIABLES NOT DIRECTLY REFERENCED BY A THREAT CATEGORY

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
Model documentation generated on 8/3/2005 10:39:10 AM by CEIP
Documentation output from RiskCalculator(tm) James W. Sewall Company

Item No.	Variable Name	Variable Description	Definition	Default Value
1	con_LeakCon_Series		Value(LeakConstruction_Series)	0
2	Consequence		.35*Conseq_Population+0.35*consq_SMYS+0.1*conseq_PIRLengthRatio+.2*Conseq_Class	0.49
3	ec_BellholeCoating		Value(BellholeCoating)	0
4	ec_coating		Value(Coating)	0.49
5	man_LeakManuf_Series		Value(LeakManufacturing_Series)	0
6	mfg_ManufacturingMethod		Value(ManufacturingMethod)	0.49
7	Nil	Dummy risk variable; value is always 0	0	0

SEGMENTATION POLICY DEFINITIONS

Risk Model Name: 2005 Risk Assessment
Version: 1.0.0.20
Description: Starting version number
Model documentation generated on 8/3/2005 10:39:10 AM by CEIP
Documentation output from RiskCalculator(tm) James W. Sewall Company

Item No.	Segmentation Name	Segmentation Attribute
1	Segmentation1	CasedHCARoadCrossings
2	Segmentation1	ClassLocation
3	Segmentation1	ConsequencePopulation
4	Segmentation1	ECAssessments
5	Segmentation1	HCA
6	Segmentation1	ICAssessments
7	Segmentation1	PressureTest
8	Segmentation1	SCCSegmentation
9	Segmentation2	CasedHCARoadCrossings
10	Segmentation2	ConsequencePopulation
11	Segmentation2	ECAssessments
12	Segmentation2	HCA
13	Segmentation2	ICAssessments
14	Segmentation2	SCCAssessments
15	Segmentation2	SCCSegmentation

1.0 PURPOSE

This procedure provides the form to be used for displaying the baseline inspection and remediation schedule that supports the baseline assessment plan.

2.0 PROCEDURE

2.1 The baseline inspection and remediation schedule shall be depicted on the electronic spreadsheet provided in this procedure.

2.2 The spreadsheet, when populated, presents the baseline inspection and remediation schedule in table form. It sorts the baseline plan by identified high consequence area (HCA) by pipeline segment. It shows the risk ranking for each HCA and identifies the applicable threats. The form also displays the scheduled assessment date and the method of assessment to be used.

2.3 This form is to be used in conjunction with Procedure PS-03-01-220: “Baseline Assessment Plan” and Procedure PS-03-01-224: “Assessment Methods Selection Process”.

2.4 Use of the form is self-explanatory.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- None

3.3 Related Procedures/Supporting Documents

- PS-03-01-220, Baseline Assessment Plan Procedure
- PS-03-01-224, Assessment Methods Selection Process Procedure

3.4 Forms and Attachments

- Baseline Inspection and Remediation Schedule

4.0 DEFINITIONS

- **HCA Affect** - The length of pipeline that intersects or tangentially touches a HCA or affects a HCA through a transport process.

1.0 PURPOSE

This procedure provides a flowchart (see Section 3.4) for determining the assessment method to be used for assessing the integrity of the Company's natural gas transmission pipeline systems.

2.0 PROCEDURE

The flowchart presented in this procedure is a decision tree matrix that provides a standardized methodology for determining which of the following five assessment methods should be used for assessing the integrity of the Company's pipelines.

- Pressure test
- In-line inspection
- External corrosion direct assessment
- Internal corrosion direct assessment
- Stress corrosion cracking direct assessment

The flowchart is subdivided into four sections and presents a series of questions to guide the user to a logical, documental conclusion concerning the appropriate assessment methodology for the pipeline segment in question.

This flowchart shall be used in conjunction with Procedure PS-03-01-220: "Baseline Assessment Plan", for developing the baseline assessment plan, including revisions to the plan when there are pipeline revisions, enhancements or additions that impact the pipeline segment.

The flowchart is intended to be used in electronic format. As one works through the decision tree in the flowchart, each "Yes" and "No" block shall be colored either red or green, with green meaning the path followed, and red for the path not followed. Also, the final result block shall be colored green.

Each marked up flowchart shall be saved in the permanent integrity management data base. The original marked up charts represent the baseline and support the Baseline Assessment Plan. If there are future revisions to the baseline flowcharts, they shall be saved as separate files. The original saved flowcharts shall not be revised, nor shall revisions be updated. Any time a flowchart is updated it shall be saved as a separate file. The purpose is to have a paper trail of revisions to show changes over time.

The annual assessment plan shall be reviewed and updated annually. The assessment method selection process flowcharts shall be reviewed and updated, and new ones added as appropriate, during the annual assessment plan update.

Updates to the flowcharts shall be based on feedback collected throughout the year from the various assessment process activities - in-line inspections, pressure tests, external corrosion direct assessments, internal corrosion direct assessments, and stress corrosion cracking direct assessments - and from updates to the risk assessment.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- None

3.3 Related Procedures/Supporting Documents

- PS-03-01-220, Baseline Assessment Plan Spreadsheet Procedure

3.4 Forms and Attachments

- Assessment Method Selection Flowchart

4.0 DEFINITIONS

- None

1.0 PURPOSE

This procedure describes the components and development of the Direct Assessment Plan.

2.0 PROCEDURE

The Company's natural gas transmission pipelines are assessed for integrity using one of three methods: pressure testing, in-line inspections, and direct assessments.

The Company's Baseline Assessment Plan includes the following:

- Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification.

- The methods selected to assess the integrity of the pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The assessment method or methods selected shall be based on the threats identified to the covered pipeline segment.

- A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule.

- A direct assessment plan.

Direct assessment is an integrity assessment method that utilizes a rigorous, structured process for collecting, integrating and analyzing knowledge of the physical characteristics and operating history of pipeline segments with the results of inspection, direct examination, and evaluation to determine the integrity of the pipeline segment.

Direct assessment is limited in use as a primary assessment method to address only the following threats: external corrosion, internal corrosion, and stress corrosion cracking.

Direct assessment may also be used as a supplemental assessment method for any applicable threat, provided the requirements of confirmatory direct assessment are followed.

The Company's Direct Assessment Plan is defined by the following procedures:

- Procedure PS-03-01-232, External Corrosion Direct Assessment
- Procedure PS-03-01-238, Dry Gas - Internal Corrosion Direct Assessment
- Procedure PS-03-01-240, Stress Corrosion Cracking Direct Assessment
- Procedure PS-03-01-260, Continual Process for Evaluation and Assessment

The procedures are based on the requirements of:

- 49 CFR Part 192 Subpart O
- ASME B31.8S
- NACE RP0502-2002 recommended practice for external corrosion direct assessment
- NACE RP0204-2004 recommended practice for stress corrosion cracking direct assessment
- NACE SP0206-2006 standard practice for Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)

The Direct Assessment Plan is initiated through the Procedure PS-03-01-224: "Assessment Methods Selection Flowchart" which the Company uses to assure a structured, consistent process for selecting the appropriate assessment method for the identified threat.

The appropriate direct assessment procedure identified above is used to conduct the assessment.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S
- NACE RP0502-2002 Recommended Practice for External Corrosion Direct Assessment
- NACE RP0204-2004 recommended practice for stress corrosion cracking direct assessment
- NACE SP0206-2006 standard practice for Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)

3.3 Related Procedures/Supporting Documents

- PS-03-01-220, Baseline Assessment Plan Procedure
- PS-03-01-224, Assessment Methods Selection Flowchart Procedure
- PS-03-01-232, External Corrosion Direct Assessment Procedure
- PS-03-01-238, Dry Gas - Internal Corrosion Direct Assessment Procedure
- PS-03-01-240, Stress Corrosion Cracking Direct Assessment Procedure
- PS-03-01-260, Continual Process for Evaluation and Assessment Procedure

3.4 Forms and Attachments

- None

4.0 DEFINITIONS

- None

1.0 PURPOSE

This procedure establishes the process for conducting direct assessments of the external corrosion threat in natural gas pipelines. Direct assessment is a structured process through which knowledge of the physical characteristics and operating history of a pipeline system or pipeline segment is integrated with the results of indirect inspection, direct examination and evaluation in order to determine the pipeline's integrity.

2.0 PROCEDURE

2.1 The External Corrosion Direct Assessment (ECDA) process helps find representative corrosion defects on a pipeline segment, but it may not find all corrosion defects on the segment. If corrosion defects that exceed allowable limits are found, it may be assumed that other similar defects may be present elsewhere in the ECDA region.

2.2 ECDA addresses both galvanic corrosion and microbiologically influenced corrosion (MIC).

2.3 ECDA includes the following four steps:

- **Pre-Assessment.** The Pre-Assessment Step collects historic and current data to determine whether ECDA is feasible, defines ECDA regions, and selects indirect inspection tools. The types of data to be collected are typically available in construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records, and inspection reports from prior integrity evaluations or maintenance actions.

- **Indirect Inspection.** The Indirect Inspection Step covers aboveground inspections and/or inspections from the ground surface to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity may have occurred or may be occurring. Two or more 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.

- **Direct Examination.** The Direct Examination Step includes analyses of indirect inspection results to select sites for excavations and pipe surface evaluations. The data from the direct examinations are combined with prior data to identify and assess the impact of external corrosion on the pipeline. Additionally, evaluation of pipeline coating performance, corrosion defect repairs, and mitigation of corrosion protection faults are included in this step.

- **Post Assessment.** The Post Assessment Step covers analyses of data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals.

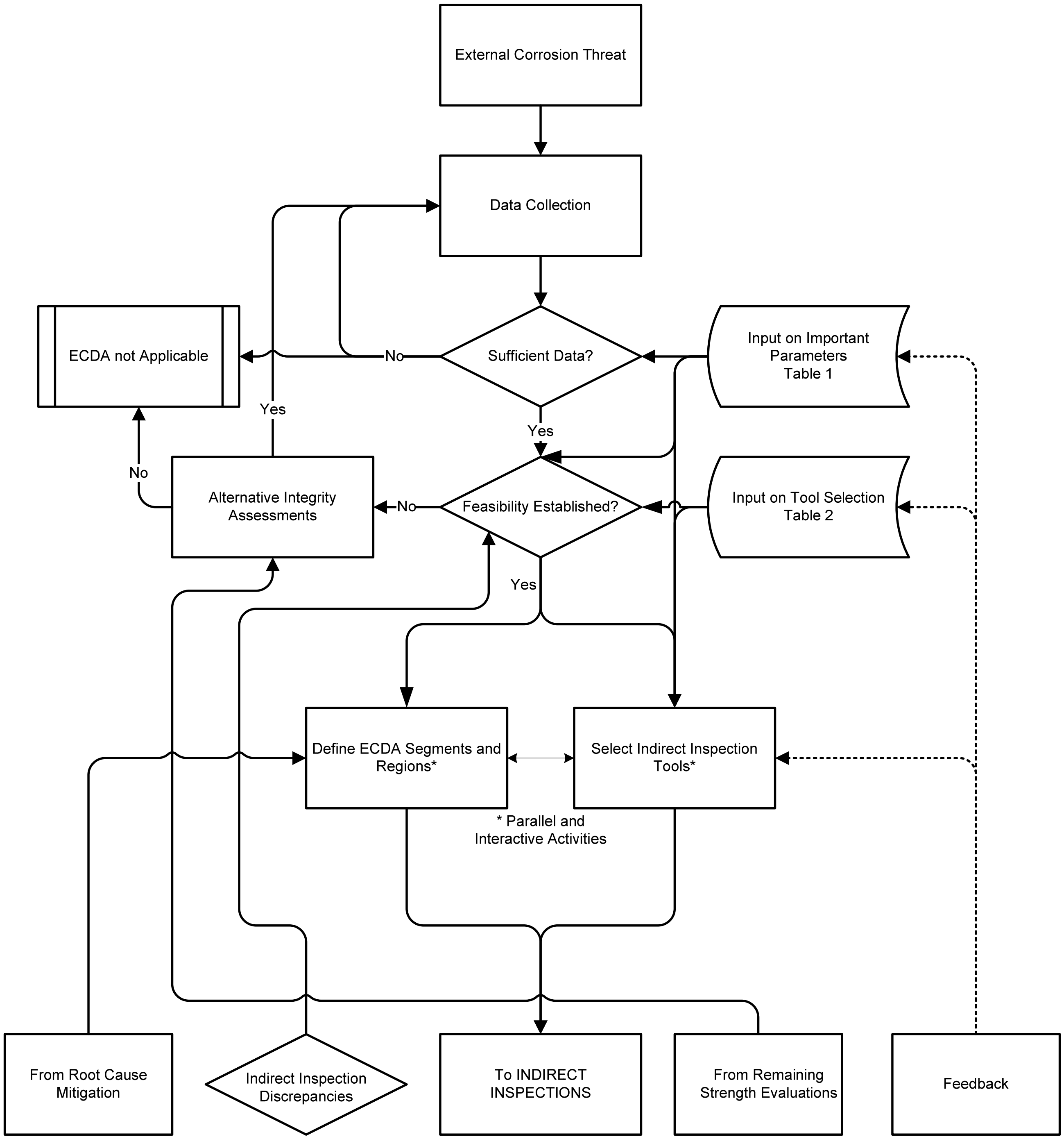
- If the Company so chooses, the Indirect Inspection Step may be omitted entirely, provided a 100% direct examination is conducted over the entire length of the pipeline segment. In this case, indirect inspections followed by selected direct examinations are not required. However, the Pre-Assessment and Post Assessment Steps must still be performed.

3.0 PRE-ASSESSMENT STEP

3.1 Figure 1 provides a flowchart for the Pre-Assessment Step.

3.2 ECDA region definition and indirect inspection tool selection are two separate, distinct activities that are part of the Pre-Assessment Step. These activities occur in parallel, and are interactive; however, they will be discussed sequentially in this procedure.

FIGURE 1: Pre-Assessment Step Flowchart



3.3 Data Collection

- Historical and current data shall be collected along with physical information for the segment to be evaluated.

- Minimum data requirements shall be defined based on the history and condition of the pipeline segment. Data elements in Table 1: "ECDA Data Elements" have been prioritized as Required or Optional. Required and optional data elements are defined as follows:

  - Required- Data elements required to execute ECDA. Any exceptions and conservative assumptions shall be documented in the event the company elects to execute ECDA where some required data elements are unavailable at the time of pre-assessment preparation. Documentation will be stored in the feasibility section of the pre-assessment document (Section 16.4 of this procedure).

  - Optional- Data elements not required for execution of ECDA. The Company shall make diligent effort to complete all optional data elements.

- All parameters that impact indirect inspection tool selection and ECDA region definition shall be considered for initial ECDA process applications on a pipeline segment.

- At a minimum, the data elements shown in Table 1: "ECDA Data Elements", shall be addressed. The data elements provide guidance on the types of data to be collected. Not all items in Table 1 are necessary for the entire pipeline. When approved by the Company, conservative defaults may be substituted as applicable. Also, it may be determined that items not in Table 1 are necessary. The elements are divided into five categories:

  - Pipe-related
  - Construction-related
  - Soils/environmental
  - Corrosion Control
  - Operational Data

Table 1: ECDA Data Elements

(Shaded items are most important for tool selection purposes)

Data Elements (R) = Required (O) = Optional	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
PIPE-RELATED			
Material (steel, copper, etc.) and grade (R)	ECDA not appropriate for nonferrous materials	Special considerations should be given to locations where dissimilar metals are joined.	Can create local corrosion cells when exposed to the environment.
Diameter (R)	May reduce detection capability of indirect inspection tools.		Influences CP current flow and interpretation of results.
Wall thickness (R)			Impacts critical defect size and remaining life predictions.
Year manufactured (O)			Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.
Seam type (O)		Locations with pre-1970 low-frequency electric resistance welded (ERW) or flash welded pipe with increased selective seam corrosion susceptibility may require separate ECDA regions.	Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW or flash-welded pipe seams may be subject to higher corrosion rates than the base metal.
Bare pipe (R)	Limits ECDA application. Fewer available tools	Segments with bare pipe in coated pipelines should be in separate ECDA regions.	
CONSTRUCTION-RELATED			
Year installed (O)			Impacts time over which coating degradation may occur, defect population estimates, and corrosion rate estimates.
Route changes and modifications (R)		Changes may require separate ECDA regions	
Route maps and aerial photos (O)		Provides general applicability info and ECDA region selection guidance	Typically contain pipeline data that facilitates ECDA
Construction practices (O)		Construction practice differences may require separate ECDA regions.	May indicate locations at which construction problems may have occurred; e.g., backfill practices influence probability of coating damage during construction.

Table 1: ECDA Data Elements (Cont'd)
(Shaded items are most important for tool selection purposes)

Data Elements (R) = Required (O) = Optional	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
CONSTRUCTION-RELATED (Cont'd)			
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, tie-ins, insulating joints (R)		Significant drains or changes in CP current should be considered separately; special considerations should be given to locations at which dissimilar metals are connected.	May impact local current flow and interpretation of results; dissimilar metals may create local corrosion cells at points of contact; coating degradation rates may be different from adjacent regions.
Locations of and construction methods used at casings (R)	May preclude use of some indirect inspection tools.	Requires separate ECDA regions	May require extrapolation of nearby results to inaccessible regions. Additional tools and other assessment activities may be required.
Locations of bends, including miter bends and wrinkle bends (O)		Presence of miters and wrinkle bends may influence ECDA region selection.	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results
Depth of cover O)	Restricts use of some indirect inspection techniques.	May require different ECDA regions for different ranges of depths of cover.	May impact current flow and interpretation of results.
Underwater sections; river crossings (R)	Significantly restricts use of many indirect inspection techniques.	Requires separate ECDA regions.	Changes current flow and interpretation of results.
Locations of river weights and anchors (O)	Reduces available indirect inspection tools	May require separate ECDA regions.	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized, which affects local current flow and interpretation of results.
Proximity to other pipelines, structures, high-voltage electric transmission lines, and rail crossings (R)	May preclude use of some indirect inspection methods.	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions.	Influences local current flow and interpretation or results.
SOILS/ENVIRONMENTAL			
Soil characteristics/types (O)	Some soil characteristics reduce the accuracy of various indirect inspection techniques	Influences where corrosion is most likely; significant differences generally require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.

Table 1: ECDA Data Elements (Cont'd)
(Shaded items are most important for tool selection purposes)

Data Elements (R) = Required (O) = Optional	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
SOILS/ENVIRONMENTAL (Cont'd)			
Drainage (R)		Influences where corrosion is most likely; significant differences may require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rates and remaining life assessment.
Topography (R)	Conditions such as rocky areas can make indirect inspections difficult or impossible		
Land use (current/past) (R)	Paved roads, etc., influence indirect inspections tool selection.	Can influence ECDA application and ECDA region selection.	
Frozen ground (R)	May impact applicability and effectiveness of some ECDA methods.	Frozen areas should be considered separate ECDA regions.	Influences current flow and interpretation of results.
CORROSION CONTROL			
CP system type (anodes, rectifiers and locations) (R)	May affect ECDA tool selection		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow and interpretation of results.
Stray current sources/locations (R)			Influences current flow and interpretation of results
Test point locations (or pipe access points) (R)		May provide input when defining ECDA regions	
CP criteria (R)			Used in post-assessment analysis
CP maintenance history (R)		Coating condition indicator	Can be used in interpreting results
Years without CP applied (O)		May make ECDA more difficult to apply	Negatively affects ability to estimate corrosion rates and make remaining life predictions.
Coating type – pipe (O)	ECDA may not be appropriate for disbonded coatings with high dielectric constants, which can cause shielding.		Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.
Coating type – joints (O)	ECDA may not be appropriate for coatings that cause shielding		Shielding due to certain joint coatings may lead to requirements for other assessment activities

Table 1: ECDA Data Elements (Cont'd)
(Shaded items are most important for tool selection purposes)

Data Elements (R) = Required (O) = Optional	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
CORROSION CONTROL (Cont'd)			
Coating condition (O)	ECDA may be difficult to apply with severely degraded coatings		
Current demand (O)			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area.
OPERATIONAL DATA			
Pipe operating temperature (O)		Significant differences generally require separate ECDA regions	Can locally influence coating degradation rates
Operating stress levels and fluctuations (O)			Impacts critical flaw size and remaining life predictions
Monitoring programs (Coupons, patrol, leak surveys, etc.) (R)		May provide input when defining ECDA regions	May impact repair, remediation, replacement schedules.
Pipe inspection reports – excavation (O)		May provide input when defining ECDA regions	
Repair history/records – such as steel/composite repair sleeves, repair locations, etc. (O)	May affect ECDA tool selection	Prior repair methods, such as anode additions, can create a local difference that may influence ECDA region selection	Provides useful data for post-assessment analyses such as interpreting data near repairs
Leak/rupture history (external corrosion) (R)		Can indicate condition of existing pipe	
Evidence of external microbiologically influenced corrosion (O)			MIC may accelerate external corrosion rates
Type/frequency – third party damage (O)			High third-party damage areas may have increased indirect inspection coating fault defects.
Data from previous over-the-ground or from-the-surface surveys (O)			Essential for pre-assessment and ECDA region selection
Hydrotest dates/pressures* (O)			Influences inspection intervals

Table 1: ECDA Data Elements (Cont'd)
(Shaded items are most important for tool selection purposes)

Data Elements (R) = Required (O) = Optional	Indirect Inspection Tool Selection	ECDA Region Definition	Use and Interpretation of Results
OPERATIONAL DATA (Cont'd)			
Other prior integrity-related activities: close interval survey, ILI runs, etc. (O)	May impact ECDA tool selection – isolated vs. larger corroded areas		Useful post-assessment data

*In the absence of Hydrotest data (dates/pressures) establish 5-year operating history to define any changes in operating pressure (increases), MAOP increases or stress leading to cyclic fatigue increase.

- The data collected in the Pre-Assessment Step often includes the same data typically considered in an overall pipeline risk (threat) assessment. Depending on the integrity management plan and its implementation, the ECDA Pre-Assessment step may be conducted in conjunction with a general risk assessment effort.

- In the event that it is determined that sufficient data for some ECDA regions comprising a pipeline segment are not available or cannot be collected to support the Pre-Assessment step, ECDA shall not be used for those ECDA Regions.

- The pre-assessment form provided in this procedure is an Excel spreadsheet with specific tabs addressing the 5 data element tables, segment and region definition, tool selection, feasibility, tool spacing, tool sensitivities, more restrictive criteria, and change log.

- The spreadsheet is available in Section 16.4 of this procedure. This pre-assessment form shall be utilized for all ECDA assessments.

- The change log (referenced above) shall be utilized to document any required changes that present in any of the 4 steps of ECDA.

3.4 ECDA FEASIBILITY ASSESSMENT

- Integrate and analyze the data collected in the Pre-Assessment Step to determine whether conditions for which indirect inspection tools cannot be used or that would preclude ECDA application exist. The following conditions may make it difficult to apply ECDA:

  - Locations at which coatings cause electrical shielding
  - Backfill with significant rock content or rock ledges
  - Certain ground surfaces such as pavements, frozen ground, and reinforced concrete
  - Situations that lead to an inability to acquire aboveground measurements in a reasonable time frame
  - Locations with adjacent buried metallic structures

   - Inaccessible areas

- If there are locations along a pipeline segment at which indirect inspections are not practical, for example, at certain cased road crossings, the ECDA process may be applied if other methods for assessing the integrity of the location in question are used.

- If the conditions along a pipeline segment are such that indirect inspections or alternative methods of assessing integrity cannot be applied, the ECDA process is no longer applicable.

   - Documentation of ECDA feasibility will be stored in the 'feasibility' section of the pre-assessment document (Section 16.4 of this procedure).

3.5 Identification of ECDA Segments

- The data collected in the pre-assessment step shall be analyzed to identify ECDA segments. An ECDA segment is a portion of a pipeline that is (to be) assessed using ECDA. An ECDA segment consists of one or more ECDA regions. ECDA segments shall be defined according to similarities of land use and topography to allow divisions of a pipeline section into manageable sub-parts of covered segments (HCAs).

- Under application of Method 2 for HCA definition (potential impact zone) with more than one HCA, an ECDA segment describes a section of pipeline that includes both HCA and non-HCA areas (covered and non-covered segments).

- Identification of ECDA segments is defined in the pre-assessment form in Section 16.4 of this procedure.

3.6 Identification of ECDA Regions

- The data collected in the Pre-Assessment Step shall be analyzed to identify ECDA regions. An ECDA 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.

- Consider all conditions that could significantly affect external corrosion when defining criteria for ECDA regions. Table 1 and Table 2 can be used as guidance in establishing ECDA regions.

- The ECDA regions may be modified based on results from the Indirect Inspection Step and the Direct Examination Step. Any modifications require an entry in the pre-assessment change log.

- ECDA Region designators will also be used to identify non-HCA areas for enhanced record-keeping purposes. Although the non-HCA areas are not ECDA Regions, assigning the non-HCA areas an ECDA Region number will maintain the identity of the area for future reference of records and data applicable to the area.

- Figure 2 provides the definitions of an ECDA segment and ECDA region.

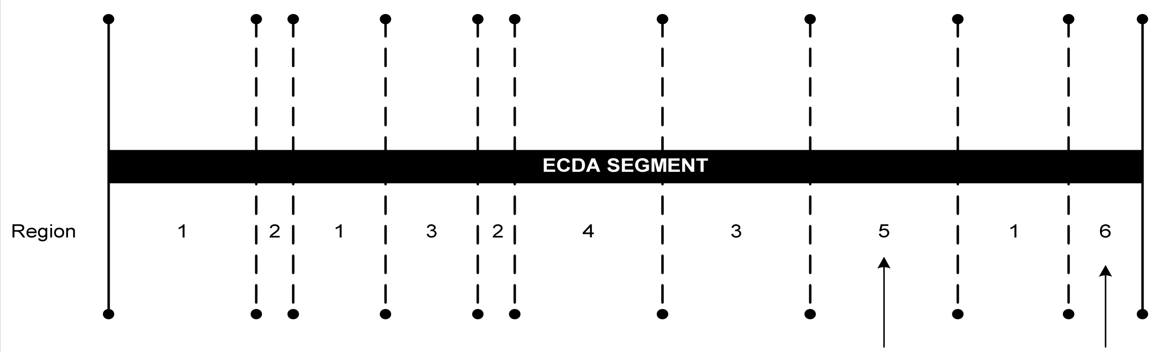
- Identification of ECDA Regions is defined in the pre-assessment form in Section 16.4 of this procedure.

FIGURE 2: ECDA Segment and Region Definitions

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

ECDA REGION
A section or sections of a pipeline within an ECDA segment that have similar physical characteristics and operating history and in which the same indirect inspection tools are used.

Example:



Region Characteristics (Year of Installation, Coating, Other):

Region 1 – 1960, Coal Tar, Surface Soil
Region 2 – 1960, Coal Tar, Cased
Region 3 – 1960, Coal Tar, Surface Pavement
Region 4 – 1978, Epoxy (FBE), Surface Soil
Region 5 – 1960, Coal Tar
Region 6 – 1978, Epoxy (FBE)

Non-HCA = There are no High Consequence Areas (covered segments) within this ECDA Region. Details concerning this are addressed in the Pre-assessment step documentation.

3.7 SELECTION OF INDIRECT INSPECTION TOOLS

- A minimum of two indirect inspection tools shall be selected for all locations and regions where ECDA is to be applied along a pipeline segment.
    - ➢ Indirect inspection tools shall be selected based on their ability to detect corrosion activity and/or coating holidays reliably under the specific pipeline conditions to be encountered.
    - ➢ Care and consideration shall be taken to select indirect inspection tools that are complementary. For example, tools shall be selected such that the strengths of one tool compensate for the limitations of another.

Table 2A "Complimentary Nature of Tools" provides guidance in selecting tools that are complimentary.

- The "Indirect Inspection Tool Selection" column in Table 1 includes items that shall be considered when selecting indirect inspection tools. The items that are shaded are most important for tool selection purposes.

- Table 2: "ECDA Tool Selection Matrix," provides additional guidance on selecting indirect inspection tools and specifically addresses conditions under which some indirect inspection tools may not be practical or reliable. The instructional procedures for each of the tools and manufacturer's operating instructions shall also be consulted for information on tool selection.

- The techniques included in Table 2 are not intended to illustrate the only inspection methods that are applicable or the capabilities of these inspection methods under all conditions. They are listed as a representative example of the types of indirect inspection methods available for an ECDA program. Other approved indirect inspection methods may be used as required by the unique situations encountered along a pipeline.

  - The same indirect inspection tools do not have to be used at all locations along the pipeline segment. Figure 2A: "ECDA Regions and Tool Selection" demonstrates how the selection of indirect inspection tools may vary along a pipeline segment.

  - To obtain reliable, accurate data, use of more than two indirect inspection tools to detect corrosion activity may be required. The minimum requirement is two tools, and use of more than two tools for specific situations shall also be determined.

Table 2: ECDA Tool Selection Matrix (A)

Conditions	Close Interval Survey (CIS)	Direct Current Voltage Gradient Survey (DCVG)	Pipeline Current Mapper (PCM)	Alternating Current Voltage Gradient Survey (ACVG)	Surface Potential Survey (SPS)	C-Scan
Coating Holidays	2	1,2	2	2	3	1,2
Anodic zones on bare pipe.	2	3	3	3	2	3
River or water crossing	2	3	2	3	3	1,2
Under frozen ground	3	3	2	2	3	1,2
Stray Currents	2	1,2	2	1,2	3	1,2
Shielded Corrosion Activity	3	3(B)	3	3(B)	3	3
Adjacent metallic structures	2	1,2	2	1,2	2	1,2
Near parallel pipelines	2	1,2	2	1,2	2	1,2
Under HVAC electric transmission lines	2	1,2	3	3	2	3
Shorted casing	3	3	3	3	3	3
Under Pavement	3(C)	3(C)	2	1,2	3(C)	1,2
Uncased crossing	2	1,2	2	1,2	2	1,2
Cased piping (insulated)	3(D)	3(D)	2	3(D)	3	2
At deep burial locations (limited)	2	1,2	2	1,2	2	2
Wetlands (limited)	2	1,2	2	1,2	2	1,2
Rocky terrain/rock ledges/rock backfill (limited)	2	1,2	2	1,2	2	1,2

Notes:

(A) Limitations and detection capabilities: All survey methods are limited in sensitivity to the type and makeup of the soil, presence of rock and rock ledges, type of coating such as high dielectric tapes, construction practices, interference currents, other structures, etc. At least two or more survey methods may be needed to obtain desired results and confidence levels required.

(B) DCVG and ACVG measurement results can provide insight on shielded coating conditions by identifying areas where an electrolytic path exist between pipe steel (under coating) and the outside environment.

(C) Applicable with pavement hole drilling to allow electrode contact with underlying soil.

(D) Applicable for conditions where carrier pipe is electrically isolated from casing pipe and an electrolyte is present in the annulus.

Key:

1 = Applicable: small coating holidays (isolated and typically < 1 in^2) and conditions that do not cause fluctuations in CP potentials under normal operating conditions.

2 = Applicable: large coating holidays (isolated and continuous) or conditions that cause fluctuations in CP potentials under normal operating conditions.

3= Not Applicable: Not applicable to this tool or not applicable to this tool without additional considerations.

Table 2A: Complimentary Nature of Tools

Note: Tools listed in the “Inspection Tools” column are considered complimentary with tools marked “X”

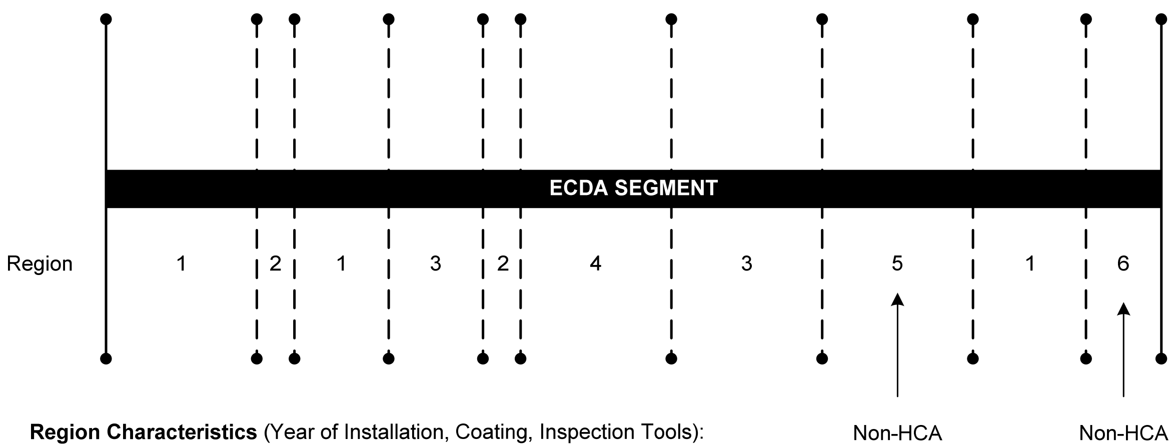
Inspection Tools	Close Interval Survey (CIS)	Direct Current Voltage Gradient (DCVG)	Pipeline Current Mapper (PCM)	Alternating Current Voltage Gradient (ACVG)	Surface Potential Survey (SPS)	C-SCAN
CIS		X	X	X	X	X
DCVG	X		X			X
PCM	X	X				
ACVG	X					
SPS	X					
C-SCAN	X	X				

FIGURE 2A: ECDA Regions and Tool Selection

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

ECDA REGION
A section or sections of a pipeline within an ECDA segment that have similar physical characteristics and operating history and in which the same indirect inspection tools are used.

Example:



Region Characteristics (Year of Installation, Coating, Inspection Tools):

Region 1 – 1960, Coal Tar, Surface Soil --- Inspection Tools: CIS and DCVG
Region 2 – 1960, Coal Tar, Cased --- Inspection Tools: ECDA not applicable
Region 3 – 1960, Coal Tar, Surface Pavement --- Inspection Tools: CIS and PCM
Region 4 – 1978, Epoxy (FBE), Surface Soil --- Inspection Tools: CIS and DCVG
Region 5 – 1960, Coal Tar --- Non-HCA – ECDA not considered
Region 6 – 1978, Epoxy (FBE) --- Non-HCA – ECDA not considered

Non-HCA = There are no High Consequence Areas (covered segments) within this ECDA Region. Details concerning this are addressed in the Pre-assessment step documentation.

3.8 INDIRECT INSPECTION TOOL CONSIDERATIONS

- Basic Limitations

  - Shielding by Disbonded Coatings – None of these indirect inspection tools is capable of detecting problems that are shielded by disbonded coatings with no electrically continuous path to the soil. If there is an electrically continuous pathway to the soil, such as through a small holiday or orifice, some tools may detect problem areas. Pinholes are problematic with nearly all tools.

  - Pipe Depths – All of the indirect inspection tools are less sensitive when pipe burials exceed normal depths. Field conditions and terrain may affect depth ranges and detection sensitivity.

- Instrumentation and Measurement Guidelines

  - The Company's inspection and test procedures identified in the Reference section of this procedure provide guidance on instruments and measurements.

- ECDA tool information shall be recorded in the identified sections of the Pre-Assessment form in Section 16.4 of this procedure for the following items:

  - Tool selection
  - Tool spacing
  - Tool sensitivity

  Changes to initial tool selection or tool spacing and the reason for the change will be recorded in the Change Log section of the Pre-Assessment form.

3.9 ECDA Pre-Assessment- More Restrictive criteria for first time application of ECDA

- Listed below are general More Restrictive Criteria considerations. Documentation of applicable criterion (one minimum) shall be recorded in the Pre-Assessment form (Section 16.4 of this procedure) under "More Restrictive Criteria."

- For a given pipeline segment, all identified attributes and data elements are assigned or referenced to a pipeline station number increasing the available data for risk analyses and the effectiveness of the direct assessment process.

- Non-HCA areas contained within an ECDA segment - Construction records, operating and maintenance histories, alignment sheets, corrosion survey records, other aboveground inspection records are collected in areas designated as Non-HCA (gaps between the C-FER potential impact circle) . These Non-HCA areas are assigned sequential ECDA segment Region numbers.

    - This allows the accumulation of complete and continuous pipeline information within an ECDA segment;

    - Facilitate the ability to apply actions found in HCA areas to other pipeline segments in accordance with Part 192.917(b) *Data gathering and integration;*

    - In the event of expanded HCA areas within the ECDA segment, the data element information is already in place to expedite the implementation of remaining assessment processes.

- ECDA segments are defined according to similarities of land use and topography. This allows realistic division of a pipeline section into manageable sub-parts of covered segments (HCAs). Region definition is unique to a specific ECDA segment. This process results in more direct examinations as compared to a situation where only one ECDA segment defines a lengthy section of pipeline routed through varying land use and topographical conditions.

- Coordination with local operations personnel for site visits and consultation for validation of conditions.

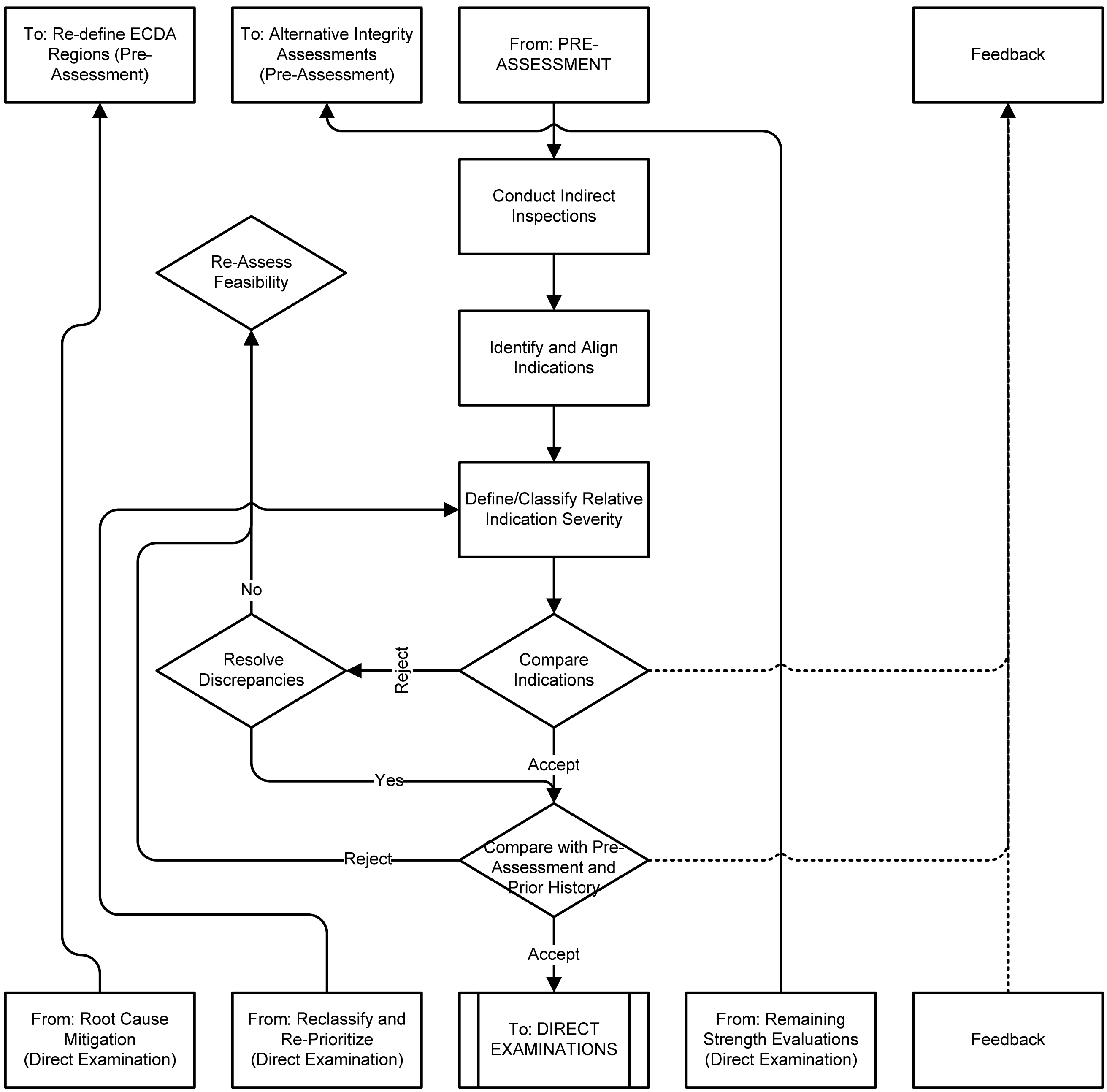
- Format of pre-assessment form to address conditions and use and interpretation of data with region definitions and tool selection on each data element (5 total).

4.0 INDIRECT INSPECTION STEP

4.1 The objective of the Indirect Inspection Step is to identify and define the severity of coating faults, other anomalies, and areas at which corrosion activity may have occurred or may be occurring.

4.2 Figure 3 provides a flowchart of the Indirect Inspection Step.

FIGURE 3: Indirect Inspection Step Flowchart



4.3 The Indirect Inspection Step requires the use of at least two at-grade or aboveground inspections over the entire length of each ECDA region and includes the following activities as shown in Figure 3:

- Conducting indirect inspections in each ECDA region established in the Pre-Assessment Step
- Aligning and comparing the data

4.4 Indirect Inspection Measurements

- Prior to conducting the indirect inspections, the boundaries of each ECDA region identified during the Pre-Assessment Step shall be identified and clearly marked.
- Measures to assure a continuous indirect inspection are achieved over the pipeline or pipeline segment being evaluated shall be used. These measures may include some inspection overlap into adjacent ECDA regions.
- Each indirect inspection shall be conducted over the entire length of each ECDA region.
- When ECDA is applied, spot-checking and repeating indirect inspections shall be considered to ensure consistent data is obtained.
- Indirect inspections shall be conducted using spacing intervals as outlined in the tool spacing section of the Pre-Assessment form (Section 16.4 of this procedure).
- The indirect inspections shall be conducted as close together in time as practical, not to exceed 90 days. If significant changes occur between the indirect inspections, such as through a change of seasons or abandonment of pipeline facilities, comparison of the results can be difficult or invalid.
- Aboveground location measurements shall be recorded with sub-meter accuracy global positioning systems (GPS) to provide for accurate data comparison between surveys, to identify significant aboveground reference points in the survey data, and to allow for future relocation to excavation locations. GPS coordinates shall be recorded in Geographic Projection (Latitude/Longitude) Decimal Degrees. GPS may be supplemented by chain measurements from known physical attributes to anomaly locations.

4.5 Alignment and Comparison

- After the indirect inspection data are taken and recorded, indications shall be identified and aligned for comparison.

  - When applied to coated lines, the criteria for identifying indications shall be sufficient to locate coating faults regardless of corrosion activity at the fault.

  - When applied to bare and poorly coated pipelines, the criteria for identifying indications shall be sufficient to locate anodic regions.

- When aligning indirect inspection results, the impact of the spatial errors must be addressed considering the rated accuracy of the GPS and other instruments used.

- After identifying and aligning indications, define and apply criteria for classifying the severity of each indication.

  - Classification, as used in this context, is the process of estimating the likelihood of corrosion activity at each indication under typical year-round conditions. The following classifications shall be used:

    - Severe – indications that are considered as having the highest likelihood of corrosion activity.

    - Moderate – indications that are considered as having possible corrosion activity.

    - Minor – indications that are considered inactive or as having the lowest likelihood of corrosion activity.

  - The criteria for classifying the severity of each indication shall take into account the capabilities of the indirect inspection tool used and any unique conditions within an ECDA region.

  - When ECDA is applied for the first time, the classification criteria shall be as stringent as practical. In cases where it cannot be determined whether corrosion is active (based on the indications) the indications shall be classified as severe.

- Table 3: "Severity Classification Table", provides severity criteria for indirect inspection methods. Sensitivity of tools shall be considered in assigning levels of severity. The Tool Sensitivity section of the Pre-Assessment form (Section 16.4 of this procedure) details sensitivity of tools. Table 3 is considered a guideline. Specific conditions along the pipeline and the expertise level of the personnel analyzing the inspection data shall be considered when defining classification criteria.

TABLE 3: Severity Classification Table

Tool	Measurement Amplitude Change Of Indication		
	MINOR	MODERATE	SEVERE
CIS[1] (impressed current system)	Small Dips, on & off potentials both are more negative than -0.850 V	Medium Dips, on potential more negative than -0.850 V off potential not more negative than -0.850 V	Large Dips, on & off potentials both not more negative than -0.850 V
CIS[1] (constant current / sac. anodes) on-reads	Small Dips, more negative than -0.850 V	Medium Dips, not more negative than -0.850 V	Large Dips, not more negative than -0.850 V
DCVG	1-35% cathodic both on & off	35-50% cathodic on, anodic or neutral off	50-100% anodic both on & off
PCM [1] (EM, AC Current Attenuation)	1-30%	30-50%	50-100%
PCM A-Frame (ACVG)	30-50 dBμV	50-70 dBμV	> 70 dBμV (2 ft intervals around defect)
C-Scan (EM, AC Current Attenuation)	10-25%	25-60%	60-100%
Surface Potential Survey[2]	0-35% (CF base)	35-50% (CF base)	50-100% (CF base)
4-Pin Resistivity	>10,000 ohm-cm	1000-10,000 ohm-cm	<1000 ohm-cm

Note 1 - Level of dips depends on conditions peculiar to the pipeline region under study.
Note 2 – See Book 4, Corrosion Control Procedure PS-03-02-250: "Surface Potential Survey" for corrosion factor (CF).

- After indications have been identified and classified, compare the results from the indirect inspections to determine whether they are consistent.

- If two or more indirect inspection tools 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 shall be considered.

  - Preliminary direct examinations may be used to resolve discrepancies in lieu of additional indirect inspections provided the direct examinations identify a localized and isolated cause of the discrepancy.

  - If preliminary direct examinations cannot be used to resolve the discrepancies, additional indirect inspections shall be considered in accordance with Section 3.7 “Selection of Indirect Inspection Tools”, after which the data must be aligned and compared as described above.

  - If additional indirect inspections are not performed or do not resolve the discrepancies, ECDA feasibility shall be reassessed. As an alternative, other proven integrity assessment technologies may be used.

  - For initial ECDA applications to any pipeline segment, any location at which discrepancies cannot be resolved shall be classified as severe.

- After discrepancies have been resolved, compare the results with the Pre-Assessment results and prior history for each ECDA region. If it is determined that the results from the indirect inspections are not consistent with the Pre-Assessment results and prior history, ECDA region definition and ECDA feasibility shall be reassessed. As an alternative, other proven integrity assessment technologies may be used.

4.6 Severity Classification- Summary of Indications

- Indirect inspection survey data shall be reviewed with a summary of indications prepared to address all tools utilized. Severity classification shall be assigned according to Table 3 (with listed considerations).

- A summary of indications shall be prepared utilizing the form "Summary of Indirect Inspection Survey Results- Direct Examination Sites." This form is provided in Section 16.4 of this procedure.

4.7 ECDA Feasibility Reevaluation and Feedback - Indirect Inspection Step

- Review the indirect inspection process to reevaluate ECDA feasibility

    - ➢ Review field conditions and compare to information provided in the Pre-Assessment
    - ➢ Evaluate tool performance and define any tool substitutions or discrepancies.

- Document the status of ECDA feasibility (feasible or infeasible) in the Pre-Assessment form (Section 16.4 of this procedure) under "Feasibility."

4.8 ECDA Indirect Inspection- More Restrictive Criteria for First Time Application of ECDA.

- Listed below are general More Restrictive Criteria Considerations. Documentation of applicable criterion (one minimum) shall be recorded in the Pre-Assessment form (Section 16.4 of this procedure) under "More Restrictive Criteria."

    - ➢ All paved surfaces are to be bored to allow direct contact of the electrode with the subsurface electrolyte when acquiring a pipe-to-soil potentials;
    - ➢ The time window between incremental indirect inspection surveys shall not exceed 90 days to assure consistent environmental conditions exist for each survey
    - ➢ Soil resistivity measurements are taken during the conductance of all ECDA projects. The minimum measurement spacing for soil resistivity testing within an ECDA segment is start, third, two third and ending distances.

- Discretionary decision for additional soil resistivity measurements or supplemental tool application by DA technician consultation with DA manager.
- Locate and mark pipeline route with depth-of-cover measurements (location instrumentation) at 100 foot minimum spacing (see O&M Procedure 209: “Pipeline Locating”).
- Both physical measurements and GPS taken to increase confidence in accurately locating anomalies for future activities (direct examinations).
- Provide a “Summary of Indirect Inspection Survey Results with Direct Examination Site Selections” form, allowing effective reference of relevant integrated data.

5.0 DIRECT EXAMINATION STEP

5.1 The objectives of the Direct Examination Step are to determine which indications from the indirect inspections are most severe and to collect data to assess corrosion activity.

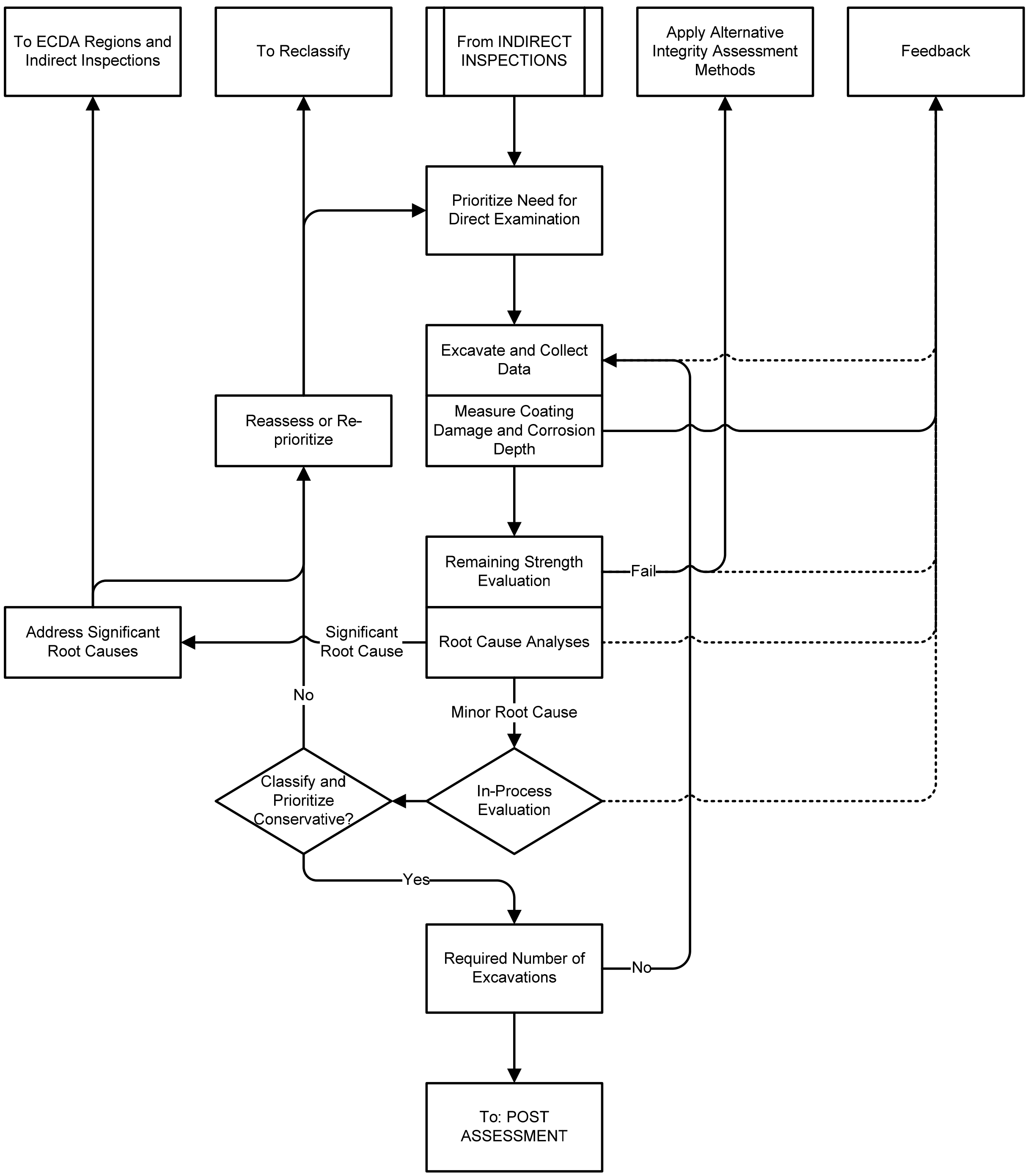
5.2 The Direct Examination Step requires excavations to expose the pipe surface so that measurements can be made on the pipeline and in the immediate surrounding environment. A minimum of one excavation is required regard-less of the results of the indirect inspections and pre-assessment.

5.3 The Direct Examination Step includes the following activities:

- Prioritization of indications found during the indirect inspections
- Excavations and data collection at areas where corrosion activity is most likely
- Measurements of coating damage and corrosion defects
- Evaluations of remaining strength (severity)
- Root cause analysis and mitigation
- In-process evaluation
- Data is collected in accordance with Procedure PS-03-01-242: “Dig Data Sheet”.

5.4 Figure 4 provides the flowchart for the Direct Examination Step.

FIGURE 4: Direct Examination Step Flowchart



5.5 Prioritization

- Prioritize the need for direct examination of each indication found during the Indirect Inspection Step. Prioritization in this context is the process of estimating the need for direct examination of each indication based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion.

- Minimum prioritization requirements are:

  - ➢ Immediate action required – this priority category shall include indications that are considered likely to have ongoing corrosion activity and that, when coupled with prior corrosion, pose an immediate threat to the pipeline under normal operating conditions.

    - o Multiple severe indications in close proximity shall be placed in this category. A minimum of three indications within 100 feet shall be considered close proximity.

    - o Isolated indications that are classified as severe by more than one indirect inspection technique at roughly the same location shall be placed in this priority category.

    - o For initial ECDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results shall be placed in this category.

    - o Consideration shall be given to placing other severe and/or moderate indirect inspection indications in the immediate category for the following conditions.

      - Significant prior corrosion suspected at or near the indication
      - Crossings with foreign pipelines, utilities or other facilities where 3rd party damage may have occurred.

    - o Indications for which the likelihood of ongoing corrosion activity cannot be determined shall be placed in this category.

  - ➢ Scheduled action required – this priority category shall include indications that may have ongoing corrosion activity but that, when coupled with prior corrosion, do not pose an immediate threat to the pipeline under normal operating conditions.

- Severe indications that are not in close proximity to other severe indications and which were not placed in the "immediate" category shall be placed in this category.

- Consideration shall be given to placing other severe and/or moderate indirect inspection indications in the scheduled category for the following conditions.

    - Significant prior corrosion suspected at or near the indication
    - Crossings with foreign pipelines, utilities or other facilities where 3rd party damage may have occurred.

➢ Suitable for monitoring – this priority category shall include indications that are considered to be inactive or as having the lowest likelihood of ongoing or prior corrosion activity.

- In setting the criteria, consideration shall be given to the characteristics of each ECDA region as follows:

    - Under year-round conditions
    - The region's history of prior corrosion
    - Crossings with foreign pipelines, utilities or other facilities where 3rd party damage may have occurred
    - The indirect inspection tools used
    - The criteria used for identification and classification of indications.

- When ECDA is applied for the first time, the prioritization criteria shall be as stringent as practical. In such cases where prior corrosion damage cannot be estimated for the indications or whether corrosion is active shall be categorized as either "immediate" or "scheduled".

- The following Table 4 provides criteria for prioritizing indirect inspection results for direct examination.

TABLE 4: Prioritization of Indirect Inspection Indications

IMMEDIATE ACTION	SCHEDULED ACTION	SUITABLE FOR MONITORING
Individual severe indications that are classified as severe by more than one indirect inspection technique.	All remaining severe indications that were not placed in an immediate action category.	All remaining indications.
Individual severe indications in regions of moderate prior corrosion.	All remaining moderate indications in regions of significant prior corrosion.	
Individual severe indications where the likelihood of ongoing corrosion activity cannot be determined.	Groups of minor indications in regions of severe prior corrosion.	
Multiple severe indications in close proximity. A minimum of three indications within 100 feet shall be considered close proximity.		
Moderate indications in regions of severe prior corrosion.		
Groups of moderate indications in regions of moderate prior corrosion.		
Any severe or moderate indications if significant prior corrosion is suspected.		
For initial ECDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results.		

5.6 Dig Priorities shall be established as follows:

- Review severity classifications for individual indirect inspection tools and combine into one severity classification representing all tools applied.

- Dig priority shall be set by translating the combined severity classification into “monitored,” “scheduled,” or “immediate” classifications as follows:

  - Minor = Monitor
  - Moderate = Scheduled
  - Severe = Immediate

- Dig priority information shall be recorded in the “Summary of Indirect Inspection Survey Results – Direct Examination Site” form (Section 16.4 of this procedure).

5.7 Guidelines for Determining the Number of Direct Examination Dig Sites for First Time Application of ECDA

- Direct Examination Step

  - Immediate Indications

    - All immediate indications require direct examination.

    - An ECDA region containing one or more immediate indications requires two (2) additional direct examinations within that region. Conditions for the two (2) direct examinations are detailed below:

      - Two (2) direct examinations of scheduled indications identified as most severe.

      - Where only one (1) scheduled indication is identified, perform a direct examination for the one (1) scheduled indication. The second direct examination shall be performed at a monitored indication identified as most likely for external corrosion in the pre-assessment and indirect inspection steps.

      - Where no scheduled indications are identified, perform two (2) direct examinations at monitored indications identified as most likely for external corrosion in the pre-assessment and indirect inspection steps.

- Scheduled Indications
  - All ECDA regions that contain scheduled indications but do not contain immediate indications.
    - A minimum of two (2) direct examinations are required in each region containing a scheduled indication. Conditions for the two (2) direct examinations are detailed below:
      - Two (2) direct examinations of scheduled indications identified as most severe.
      - Where only one (1) scheduled indication is identified, perform a direct examination for the one (1) scheduled indication. The second direct examination shall be performed at a monitored indication identified as most likely for external corrosion in the pre-assessment and indirect inspection steps.
- Monitored Indications
  - Direct examinations are not required for ECDA regions containing only monitored indications where direct examinations for either immediate, scheduled or monitored indications were performed in other ECDA regions within the same ECDA segment.
  - An ECDA segment with one or more ECDA regions containing monitored indications but does not contain any immediate or scheduled indications
    - A minimum of two (2) direct examination are required within the ECDA segment at monitored indications identified as most likely for external corrosion in the pre-assessment and indirect inspection steps. Conditions for the two (2) direct examinations are detailed below:

- For an ECDA segment that contains one (1) ECDA region, two (2) direct examinations are required.
- For an ECDA segment that contains more than one (1) ECDA region, a total of two direct examinations are required within that ECDA segment, and shall be directed to either a single region or two (2) separate regions.

- Post-Assessment Step
  - For a first-time application of ECDA
    - Two (2) confirmation direct examinations in an ECDA segment are required for ECDA process validation.
  - Direct Examination Site Selection
    - One (1) random location for direct examination to be chosen where no indirect inspection indications are present.
    - One (1) direct examination location at a scheduled or monitored indication.

- Definitions
  - ECDA Region: A section or sections of a pipeline that have similar physical characteristics and operating history and in which the same indirect inspection tools are used.
  - ECDA Segment: A portion of a pipeline that is (to be) assessed using ECDA. A segment consists of one or more ECDA regions.

5.8 Guidelines for ECDA Direct Examination of Reconditioned Pipe

- Reconditioned pipe can be characterized as follows:
  - Coating imbedded within, and bonded to defects with little or no active corrosion evident.

- ➢ Evidence of corrosion defects repaired with weld deposition or patches.
- ➢ Evidence of pre-existing mechanical couplings at the ends of each joint.
- ➢ General and/or isolated corrosion defects sustained during original service life.
- ➢ Pipe that was placed in original service as bare or poorly coated, with little to no cathodic protection during original service life.

- NACE Standard RP 0502-2002 Applications
  - ➢ 5.10.2.2.3 – States: *If the results of an excavation at a scheduled indication show corrosion that is deeper than 20% of the original wall thickness and that is deeper or more severe than at an immediate indication, at least one more direct examination is required. For first time application of ECDA, a minimum of two direct examinations shall be performed.*
  - ➢ 5.5.2 – States: *If the remaining strength of a defect is below the normally accepted level for the pipeline segment (e.g., the maximum allowable operating pressure times a suitable factor for safety), a repair or replacement is required (or the MAOP may be lowered such that the MAOP times a suitable factor of safety is below the remaining strength). In addition, alternative methods of assessing pipeline integrity must be considered for the entire ECDA region in which the defect or defects were found unless the defect or defects are shown to be isolated and unique in a root-cause analysis (see Paragraphs 5.6.1 and 5.6.2)*

- Process for Addressing Defects Associated with Reconditioned Pipe
  - ➢ Defects associated with reconditioned pipe may be classified as ‘Isolated or Unique’ (as described in NACE reference 5.5.2 above), providing the defect was not identified and classified (immediate, scheduled, monitored) in the indirect inspection step.
  - ➢ The process outlined below will be practiced for defects associated with pipe that is determined to be reconditioned:
    - o All corrosion defects found within an excavation will be measured, evaluated and documented.

  - If a corrosion defect is found to be active, and/or directly correlates with the scheduled indication (location identified in the indirect inspection step), and is measured to be deeper than 20% of original wall thickness, two (2) additional dig sites will be selected and examined as per NACE reference 5.10.2.2.3 above.

  - Pre-existing (arrested) corrosion defects (not identified in the indirect inspection step) will not be considered for the 20% metal loss application requiring additional direct examinations (see III. A. above), but will be evaluated for remaining strength.

  - In cases where pre-existing defects (corrosion/3rd party damage) are determined to be inactive/arrested (not identified in the indirect inspection step), such defects are not considered 'Time Dependent' and can be classified as 'Stable Defects' [192.917 (e) (3)]. Where such defects fail a remaining strength calculation or require immediate response, appropriate repair/replacement shall be executed. Under a 'Stable Threat' condition, ECDA is considered applicable for the region in which such a defect(s) is identified.

5.9 Schedule for ECDA Direct Examinations

- Dig priority classifications assigned for ECDA indications are based on criteria established in Table 3 "Severity Classification Table" and Table 4 "Prioritization of Indirect Inspection Indications" which occurs prior to direct examination. Actual conditions cannot be determined until exposure in direct examination. Any repairs or remediation requirements discovered upon exposure will be addressed in accordance with company procedures.

- All ECDA direct examinations shall be completed within 12 months of the date "initial dig priorities" were set as established in the form, "Summary of Indirect Inspection Survey Results - Dig Selection," (Section 16.4 of this procedure).

5.10 Excavations and Data Collection

- Excavations shall be based on the priority categories described above. Excavation sites shall be geographically located by either or both of the following methods:

- ➢ GPS [sub-meter accuracy, Geographic Projection (Latitude/Longitude) Decimal Degrees]
- ➢ Chain measurements from known physical attributes

- Before conducting excavations, define minimum requirements for consistent data collection and recordkeeping in each ECDA region. Refer to the Pre-Assessment document prior to and during the ECDA direct examination process. Minimum requirements shall include the types of data to be collected and shall take into account the conditions to be encountered, the types of corrosion activity expected, and the availability and quality of prior data. Procedure PS-03-01-242: “Dig Data Sheet” provides guidance and a standardized data collection form for use during excavations with the capability to capture additional data that is appropriate for the conditions.

6.0 DATA COLLECTION PRIOR TO COATING REMOVAL

6.1 Typical data measurements and related activities are listed below:

- Measurement of pipe to soil potentials
- Measurement of soil resistivity
- Soil sample collection
- Water sample collection
- Measurements of under-film liquid pH
- Photographic documentation
- Data for other integrity analyses such as MIC, SCC etc.

6.2 The size (length) of each excavation shall be increased if conditions that indicate severe coating damage or significant corrosion defects beyond either side of the excavation are present.

6.3 Pipe-to-Soil Potential

- The pipe-to-soil potential shall be measured with the reference electrode placed in the bank of the excavation, at various positions around the pipe, in the side of the excavation, and/or at the surface. The measurement is for information purposes since, with the excavation of the pipe, the electric field around the pipe has been altered. However, the pipe-to-soil potential at the point of excavation may help to identify dynamic stray currents in the area.

6.4 Measurement of Soil Resistivity

- Soil resistivity is an electrical property of soil and is directly related to corrosiveness. This means the lower the soil resistivity, the more corrosive the soil. Highly differing resistivity values in close proximity may cause accelerated corrosion. Soil resistivity measurements are taken in accordance with Procedure PS-03-02-240: "Soil Resistivity."

6.5 Soil and Water Sample Collection

- Soil Samples
  - ➢ Soil samples shall be collected with a clean spatula or trowel and placed in an 8-ounce plastic jar with a plastic lid. The sample jar shall be packed full to displace air. Tightly close the jar, seal with plastic tape, and using a permanent marker, record sample location on both the jar and the lid.
- Groundwater Samples
  - ➢ Water samples shall always be collected from the open ditch when possible. Completely fill an 8-ounce plastic jar, seal, and identify location with a permanent marker on both the jar and the lid.
- Laboratories
  - ➢ Soil-testing laboratories that will be performing the testing shall be specifically equipped with wet laboratory facilities designed for soil testing. Samples shall be tested for the following:
    - o Type Classification: classify soil type by the United Soil Classification System (USCS), U. S. Department of Agriculture standards, or other standards.
    - o Moisture Content: determine the moisture content of the soil. Measure a mass of soil and then oven dry to 230˚ ± 9˚ F. for a minimum of 16 hours. Measure the mass of the cooled sample and calculate the moisture content as percent of dry weight from the change in mass.

- Sulfide Ion Concentration: prepare a fresh 50% soil-water suspension by weight using deaerated water immediately after removing the soil from the sample jar. Add sulfide anti-oxidant buffer solution. Test with a selective ion electrode and a double-junction reference electrode.

- Conductivity: use a fresh amount of soil and prepare a 50% soil-water suspension by weight. Let the solution react for minimum of one-half hour. Insert the probe from the conductivity meter into the soil-water suspension and record the results.

- pH: Prepare a 50% soil-water suspension by weight, let react for one hour, and measure using a separate pH electrode and a single junction reference electrode.

- Chloride Ion Concentration: prepare a 50% soil-water suspension by weight, add ionic strength adjustor in accordance with instrument manufacturer's recommendations, and test with ion-selective electrode.

- Sulfate Ion Concentration: Prepare a 50% soil-water solution and pipette 50 mL of the water extract into a beaker. Add 50 mL of methanol-formaldehyde. Titrate with lead perchlorate.

- Corrosion Growth Rate (CGR) testing: Conducted for soil samples taken adjacent to the pipe. Equipment utilized shall be capable of accurately measuring CGR within a test time frame not to exceed 24 hours.

6.6 pH Measurement – Field Testing

- If a liquid is present beneath the coating, take a sample using a syringe or cotton swab following procedures described above for testing purposes.

- Test the pH of the liquid using hydrion paper or the equivalent. Carefully slice the coating to a length to allow the test paper to be slipped behind the coating. Press the coating against the pH paper for a few seconds and then remove the pH paper. Note and record the color of the paper in relation to the chart provided with the paper.

6.7 Microbiologically Influenced Corrosion (MIC) Analysis – Field Testing

- MIC analyses shall be performed on corrosion products when MIC is suspected. These tests shall be performed to determine whether microbial activity could be contributing to the observed corrosion. Procedure PS-03-02-296: “Bacteria Testing – Serial Dilution Method” provides additional guidance on sample collection and laboratory testing.

- Corrosion Product Analysis – Field Testing

  - After the pipe is exposed, immediately sample and test the soil and any suspected deposits. Carefully remove the coating around the suspected area of corrosion using a knife or similar instrument. Sample contamination must be kept to a minimum. Therefore, avoid touching the soil, corrosion product, or film with hands. Samples shall be obtained from the following areas:

    - Undisturbed soil immediately next to the exposed pipe steel surface or at an area of coating damage

    - A deposit associated with visual evidence of pipe corrosion

    - Liquid trapped behind the coating

  - Collect a sample of soil, deposit, film, or liquid from the area of interest. Use only a clean knife or spatula provided with the test kit. The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the back side of the coating. In all cases, note the color and type of sample. Carefully transfer the sample to the test kit vial for testing. Follow the detailed procedure given in the kit instruction sheets. For comparison purposes, obtain a reference sample taken at least 3 feet from the previous collection site.

- The form of the corrosion pits associated with MIC is reasonably distinctive. These features can be observed in the field with the unaided eye, a magnifying glass or a low-power microscope.

- After any films or products sampled above have been obtained from a corroded area, remove the remaining product using a clean spatula or knife, being careful not to scratch the metal. Clean any remaining material with a clean, dry, stiff brush, such as a nylon-bristle brush. Do not use a metal brush if possible, because the metal bristles can mar the pit features. If not all of the product can be removed with this method, use a brass bristle brush in the longitudinal direction only. Dry the area with an air blast or an alcohol swab. A shiny metallic surface of the pit suggests the possibility of active corrosion. However, judgment must be used to differentiate this condition from one created by scraping the steel surface with a metallic object, such as the knife or spatula used to clean the surface or to obtain the sample product.

- Examine the newly cleaned corroded area first visually with the unaided eye. Then use a magnifying glass or a low-power microscope to examine the detail of the corrosion pits. MIC often has the following features:
    - ➢ Large craters up to 2 to 3 inches or more in diameter
    - ➢ Cup-type hemispherical pits on the pipe surface or in the craters
    - ➢ Craters or pits sometimes surrounded by uncorroded metal
    - ➢ Striations or contour lines in the pits or craters running parallel to longitudinal pipe axis (rolling direction)
    - ➢ Tunnels sometimes at the ends of the craters, also running parallel to the longitudinal axis of the pipe

6.8 Purpose of Chemistry Testing

- Chemistry testing is performed to assist in determining contributing factors of observed corrosion and,
- To gather soil chemistry data at all direct examination sites for possible use in future statistical analysis.

7.0 COATING DAMAGE AND CORROSION DEPTH MEASUREMENTS

7.1 Measurement Considerations

- For corrosion defects, minimum requirements shall include evaluation of all significant defects. The parameters of such a defect shall be defined in terms of the remaining strength calculations as described in Book 4, Corrosion Control Procedures, Procedure PS-03-02-200: “Evaluation of Remaining Strength of Corroded Pipe”.

- Procedure PS-03-01-242: "Dig Data Sheet" provides a standardized data collection form for use during excavations with the capability to capture additional data that is appropriate for the conditions.

7.2 Measurement Categories

- Typical measurements for evaluating the condition of the coating and the pipe are listed below:

  - Identification of coating type
  - Assessment of coating condition
  - Measurement of coating thickness
  - Assessment of coating adhesion
  - Coating degradation mapping
  - Corrosion product data collection
  - Identification of corrosion defects
  - Mapping and measurement of corrosion defects
  - Photographic documentation

7.3 Coating Condition and Adhesion Assessment

- Coating inspection for holiday testing purposes shall precede any other type of coating evaluation planned. Three situations could be encountered when evaluating the pipe surface at an excavation site:

  - The coating is in excellent condition and completely adhered to the pipe surface
  - The coating is partially disbonded and/or degraded
  - The coating is completely missing; the pipe surface is bare

- When the coating is in excellent condition, the likelihood of finding external corrosion is greatly reduced. When the coating is partially disbonded and/or degraded, the likelihood of finding external corrosion is increased. Therefore, it is important to determine and document coating type and disbonded areas.

- Coatings are inspected as follows:

  - ➢ Coating shall be removed from the pipe surface using an appropriate tool. Any liquid under the coating shall be sampled. The steel surface condition and liquid pH shall be evaluated.

  - ➢ Determine the pH of ground water away from the pipe in the ditch, if possible, for reference. Compare the ground water pH to the pH of any liquid found under coating to determine whether the pH near the pipe is elevated. An elevated pH indicates the presence of CP current reaching the pipe. A pH above about 9 would be considered elevated for most soils. It is not uncommon to determine a pH of 12 to 14 for well-protected steel.

  - ➢ Visually inspect the steel surface for corrosion after the coating analysis is performed. Identify areas that may contain other types of anomalies such as stress corrosion cracking or where microbiologically induced corrosion may have contributed to external corrosion. This becomes essential when risk assessment results indicate the possibility of other threats that impact the pipeline or segment being evaluated.

  - ➢ Measure the pipe surface temperature under the coating.

7.4 Corrosion Product Removal

- Carefully remove the coating around the suspected area of corrosion using the proper tools. Sample contamination must be kept to a minimum. Avoid touching the soil, corrosion product, or film with hands or tools other than a clean knife or spatula to be used in collecting the sample.

7.5 Corrosion Product Analyses

- Corrosion product analyses may be useful in determining mechanisms or identifying unusual soil contaminants. Samples shall be obtained from the following areas:

- ➢ A deposit associated with visual evidence of pipe corrosion
- ➢ A scale or biofilm on the steel surface or the backside of the coating
- ➢ Liquid trapped behind the coating

- The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the backside of the coating.

7.6 Identification and Mapping of Corrosion Defects

- At each excavation, measure and document the extent, morphology, and depths of any external corrosion to establish the overall pipeline integrity. During the direct examination process, certain anomalies may be identified and require further analysis to establish the overall integrity of the pipeline.

- Cleaning/Surface Preparation

  - ➢ Accurate assessment of external corrosion anomalies can only be accomplished after thorough cleaning of the affected area. Following are guidelines for cleaning and preparation of the pipe surface prior to anomaly evaluation. The cleaning method chosen depends on the type of inspection technique and repair to be conducted. For instance, if risk assessment results indicate that other anomalies, such as stress corrosion cracking, may be present, cleaning methods must be modified so cleaning does not interfere with the detection of such anomalies.

  - ➢ The objective of the pipe preparation process is to remove coating residue and coating deposits to optimize the effectiveness of the inspection. The steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products, and coating remnants.

- Anomaly Measurement and Evaluation Methods

  - ➢ The exposed and cleaned pipe surface shall be examined for external corrosion and other anomalies that may be present. Such examinations shall be suitable for other anomaly types expected, in addition to external corrosion.

- The results of all pipe surface examinations shall be thoroughly documented, including photographic records.

- The residual strength of the corroded pipe shall be determined using Procedure PS-03-02-200: "Evaluation of Remaining Strength of Corroded Pipe". Residual strength of other anomaly types shall be assessed using other appropriate, Company approved methods.

- Corrosion depths may be determined using one or more of the following techniques. Additional non-destructive testing methods are typically required to determine the depths and extent of other anomaly types.

  - Pit depth gauge
  - Ultrasonic thickness probe
  - Automated methods
  - Profile gauges

7.7 Other evaluations, unrelated to external corrosion, shall be conducted as required. Such evaluations may include magnetic particle testing or ultrasonic testing.

8.0 REMAINING STRENGTH EVALUATION

8.1 Evaluate the remaining strength of defects in accordance with Procedure PS-03-02-200: "Evaluation of Remaining Strength of Corroded Pipe." If the remaining strength of a defect fails to meet the safe operating pressure for the pipeline segment, a repair or replacement is required.

9.0 ROOT CAUSE ANALYSIS AND MITIGATION

9.1 Identify any existing root cause of all significant corrosion activity. A root cause may include inadequate CP current, previously unidentified sources of interferences, or other situations.

9.2 If a root cause for which ECDA is not well suited (for example, shielding by disbonded coating or biological corrosion) is determined, consideration shall be given to alternative methods (in-line inspection and pressure testing) for assessing the integrity of the pipeline segment.

9.3 Identify and take remediation action to mitigate or preclude future external corrosion resulting from significant root causes.

9.4 After remediation actions are complete, consideration shall be given to repeating indirect inspections.

9.5 Based on the remediation actions, it may be appropriate to reprioritize the indications, as described in the following section.

10.0 IN-PROCESS EVALUATION

10.1 An evaluation to assess the indirect inspection data and the results from the remaining strength evaluation and the root cause analyses shall be performed.

10.2 The purpose of the evaluation is to critically assess the criteria used to categorize the need for repair, and to critically assess the criteria used to classify the severity of individual indications.

10.3 Assess Prioritization Criteria

- Assess the extent and severity of existing corrosion relative to the assumptions made in establishing priority categories for repair.
- If existing corrosion is less severe than originally prioritized, consider modifying the criteria and reprioritize all indications.
- If existing corrosion is more severe than originally prioritized, then the criteria shall be modified and all indications shall be reprioritized.
- Any indication for which comparable direct examination measurements show more serious conditions than suggested by the indirect inspection data shall be moved to a more severe priority category.

10.4 Assess Classification Criteria

- Assess the corrosion activity at each excavation relative to the criteria used to classify the severity of indirect inspection indications.

- If the corrosion activity is less severe than classified, consider reassessing and adjusting the criteria used to define the severity of all indications. Additionally, the criteria used to prioritize the need for repair may be reconsidered and adjusted. For initial ECDA applications, there shall be no downgrading of classification or prioritization criteria.

- If the corrosion activity is worse than classified, then the criteria used to define the severity of all indications shall be reassessed and appropriately adjusted. In addition, consider the need for additional indirect inspections and reconsider and adjust the criteria used to prioritize the need for repair.

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

10.5 Reclassification and Reprioritization

- Reprioritization is required when existing corrosion is more severe than originally assumed.

  - ➢ In general, an indication that was originally placed in the immediate category shall be moved no lower than the scheduled category as a result of reprioritization.

  - ➢ When ECDA is applied for the first time, do not downgrade any indications that were originally placed in the immediate or scheduled priority categories to a lower category.

- Reclassification is required when results from the direct examination show corrosion activity that is worse than indicated by indirect inspection data.

- Additionally, for each root cause, identify and reevaluate all other indications that occur in the pipeline segment where similar root cause conditions exist.

- If a repair and recoating or replacement is performed, the indication is no longer a threat to the pipeline and may be removed from further consideration after completion of the root cause analysis and mitigation activities.

- If remediation is performed, an indication that was initially placed in the immediate priority category may be moved to the scheduled priority category provided subsequent indirect inspections justify reducing the indication severity.

- If remediation is performed, an indication that was initially placed in the scheduled priority category may be moved to the monitored priority category if subsequent indirect inspections justify reducing the indication severity.

10.6 ECDA Feasibility Reevaluation and Feedback – Direct Examination Step

- Review the direct examination process to reevaluate ECDA feasibility
  - ➢ Review conditions found and compare to information provided in the Pre-Assessment and the Indirect Inspection.
  - ➢ Identify any threats not previously defined.
  - ➢ Record any reclassifications of severity or dig priority.

- Document the status of ECDA feasibility (feasible or infeasible) in the Pre-Assessment form (Section 16.4 of this procedure) under “Feasibility.”

10.7 ECDA Direct Examination - More Restrictive Criteria for First Time Application of ECDA

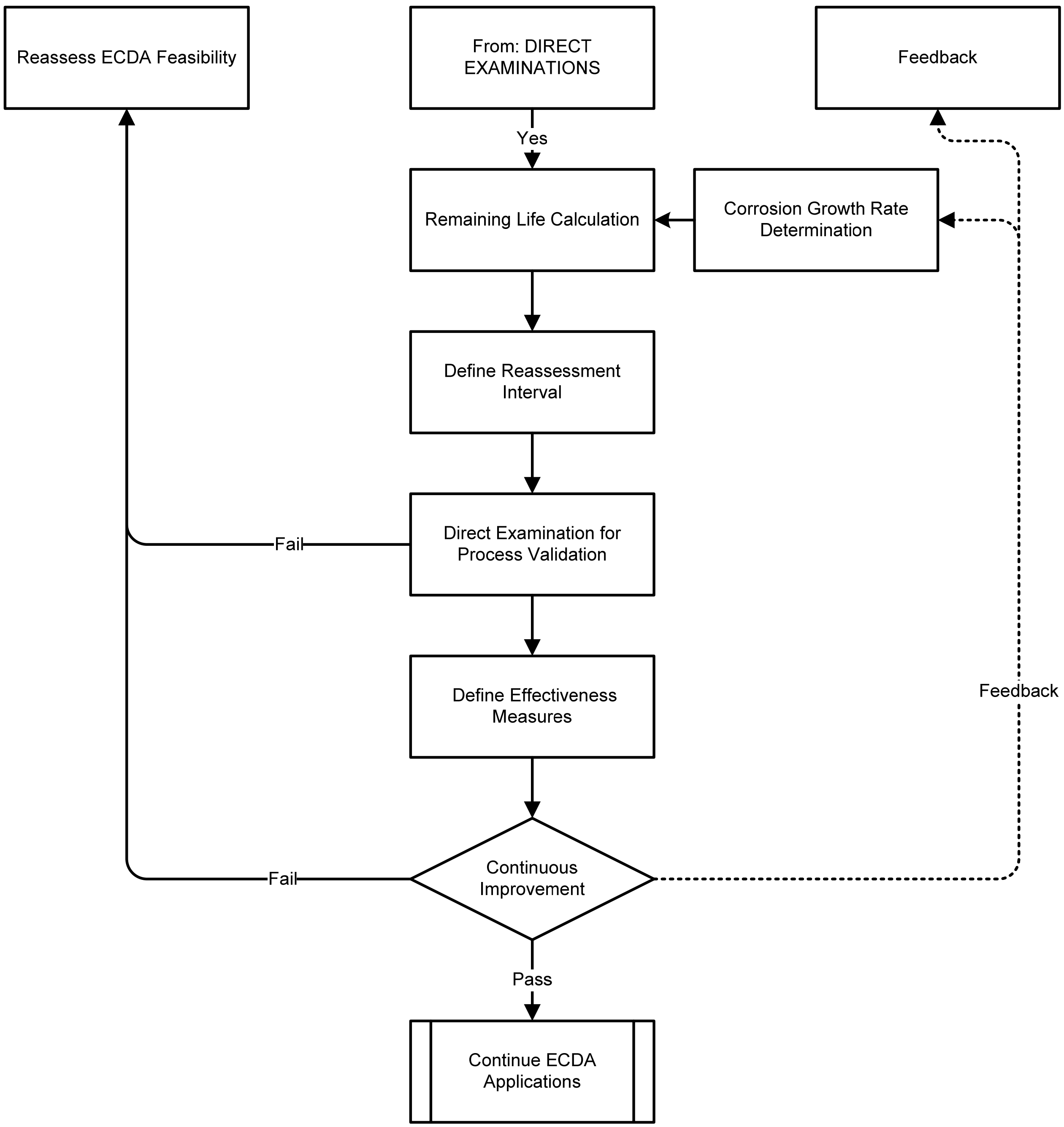
- Listed below are general More Restrictive Criteria Considerations. Documentation of applicable criterion (one minimum) shall be recorded in the Pre-Assessment form (Section 16.4 of this procedure) under “More Restrictive Criteria.”
  - ➢ Complete soil chemistry and MIC analysis, soil resistivity and pipe-to-soil potential measurements for all dig sites including validations digs.
  - ➢ Additional testing utilizing NDE methods (i.e. magnetic particle, liquid penetrant, ultrasonic, etc.) are conducted on suspect conditions (i.e. suspect girth welds, longitudinal seams, and stress risers resulting from dents or third party damage) that demand further examination.
  - ➢ Comprehensive direct examination information package including: Dig data sheet, Laboratory chemistry test data, MIC analysis, Photographs, and sufficient information to populate a pipe inspection report.

11.0 POST ASSESSMENT STEP

11.1 The objectives of the Post Assessment Step are to define reassessment intervals and assess the overall effectiveness of the ECDA process.

11.2 Figure 10 shows the flowchart for the Post Assessment Step.

FIGURE 10: Post Assessment Step Flowchart



11.3 The Post Assessment Step includes the following four major activities:

- Remaining life calculations
- Definition of reassessment intervals
- Assessment of ECDA effectiveness
- Feedback and Continuous Improvement

11.4 Remaining Life Calculations

- If no corrosion defects are found, no remaining life calculation is needed; the remaining life can be taken as the same as for a new pipeline.
- The maximum remaining life flaw size at all schedule category indications shall be taken as the same as the most severe indication in all locations that have been excavated.
  - ➢ If the root cause analyses indicate that the most severe indication is unique, the size of the next most severe indication may be used for the remaining life calculations.
  - ➢ As an alternative, a different value base on a statistical or more sophisticated analysis of the excavated severities may be substituted.
- The remaining life of the maximum remaining flaw shall be estimated using a sound engineering analysis.

- In the absence of an alternative analysis method, the following equation (2) may be used:

$$RL = C \times SM\ (t/GR) \qquad (2)$$

Where:

RL = remaining life (years)

C = calibration factor = 0.85 (dimensionless)

SM = safety margin = failure pressure ratio ÷ MAOP ratio

Failure pressure ratio = calculated failure pressure (psi) / yield pressure (psi)

MAOP ratio = MAOP (psi) / yield pressure (psi)

t = nominal wall thickness (inch)

GR = growth rate (inches per year)

- This method of calculating expected remaining life is based on corrosion that occurs continuously and on typical sizes and geometries of corrosion defects. It is considered conservative for external corrosion on pipelines. The “Corrosion Rate Estimation” section contains additional information for estimating corrosion growth.

11.5 Reassessment Intervals

- Reassessment intervals shall be defined on the basis of indications prioritized in the scheduled category. All indications categorized as immediate shall have been addressed during direct examinations. Indications in the monitor category are expected to experience insignificant growth.

- The conservatism of the reassessment interval is not easy to measure because there are uncertainties in the remaining flaw sizes, the maximum corrosion growth rates, and the periods of a year in which defects grow by corrosion. To account for these uncertainties, the reassessment interval defined in this procedure is based on a half-life concept. An estimate of the true life is made, and the reassessment interval is set at half that value.

- The estimate of true life is based on conservative growth rates and conservative growing periods. To ensure unreasonably long reassessment intervals are not used, a maximum reassessment interval that cannot be exceeded unless all indications are addressed is determined.

- When corrosion defects are found during the direct examinations, the maximum reassessment interval for each ECDA region shall be taken as one-half the calculated remaining life. The maximum reassessment interval is limited by ASME B31.8S.

- Different ECDA regions may have different reassessment intervals based on variations in expected growth rates between ECDA regions.

- Any indications that are scheduled for evaluation shall be addressed before the end of the reassessment interval (see Section 5.9 of this procedure).

- Reassessment / Reinspection intervals shall be determined in accordance with ASME B31.8S, Section 7.4.1.

11.6 Assessment of ECDA Effectiveness

- At least one additional direct examination at a randomly selected location shall be conducted to provide additional confirmation that the ECDA process has been successful.

    - For initial ECDA applications, at least two additional direct examinations are required for process validation. The direct examinations shall be conducted at randomly selected locations, one of which is categorized as scheduled (or monitored if no schedule category indications exist) and one in an area where no indication was detected.
    - If conditions that are more severe than determined during the ECDA process (that is, that result in a reassessment interval less than determined during the ECDA process) are detected, the process shall be reevaluated and repeated or an alternative integrity assessment method used.

- Performance Measures

- Number of repair actions taken due to direct examination results, for indications in both the immediate and scheduled priority categories

- Number of external corrosion leaks (for low-stress pipelines it may be beneficial to compile leaks by leak classification)

11.7 Feedback and Continuous Improvement

- Throughout the ECDA process, as well as during scheduled activities and reassessments, efforts shall be made to improve the ECDA applications by incorporating feedback at all appropriate opportunities.

- Activities for which feedback shall be considered include:

  - Identification and classification of indirect inspection results by classifying defects.
  - Data collection from direct examinations
  - Remaining strength analyses
  - Root cause analyses
  - Remediation activities
  - In-process evaluations (tracking feasibility through the first 3 steps)
  - Direct examinations used for process validation
  - Criteria for monitoring long-term ECDA effectiveness (NACE 6.4.3)

    - Reliability and Repeatability – Track the number of reclassifications and reprioritizations that occur during an ECDA process. Reclassifications and reprioritizations will be recorded in the change log section of the Pre-Assessment form and the "Summary of Indirect Inspection Survey Results – Direct Examination Sites" (section 16.4 of this procedure).

    - Application of ECDA – Track the number of excavations made (direct examinations) to investigate potential problems. The number of excavations will be recorded in the "Summary of Indirect Inspection Survey Results – Direct Examination Sites" (section 16.4 of this procedure).

    - Results of ECDA – Monitor the extent and severity of corrosion found during direct examinations. Extent and severity of corrosion will be recorded in the Dig Data Sheet (PS-03-01-242).
  - Scheduled monitoring and periodic reassessments

12.0 CORROSION RATE ESTIMATION

12.1 External corrosion rates are an essential variable for establishing the interval between successive integrity evaluations and pipeline remediation needed to assure that integrity is maintained.

12.2 When possible, external corrosion rates shall be determined by directly comparing measured wall thickness changes that are detected after a known time interval. Such data may be from maintenance records, prior excavations (for example, contained in pipeline inspection reports), or other methods such as ILI.

12.3 Other methods that may also be used for external corrosion rate estimates are defined in NACE RPO502, D1.3.

12.4 Under some conditions, external corrosion rates may also be determined using buried coupons, linear polarization rate measurements, or electrical resistance probes.

12.5 Actual corrosion rates are difficult to predict and/or measure. Corrosion estimation techniques may not simulate actual field conditions. Caution shall be exercised when computing corrosion rates.

12.6 Corrosion Rate Estimates

- Guidance for corrosion rate estimation is provided in NACE RP0502, D2.

12.7 Default Corrosion Rate

- Statistically valid methods based on the data developed may be used for corrosion rate estimates.
- When other data are not available, a pitting rate of 0.016 inches per year is recommended for determining reinspection intervals. 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 non-native backfill.

- The corrosion pitting rate above may be reduced by a maximum of 24% provided it can be demonstrated that the CP level of all pipelines or segments being evaluated have had at least 40 mV of polarization (considering IR drop) for a significant fraction of the time since installation.

12.8 Electrical Resistance (ER) Probe Measurements

- The ER probe method of estimating the corrosion growth rate is the primary method utilized by the Company.

    - ➢ The ER probe method does not give real-time results. However, equipment utilized has the capability to give Corrosion Growth Rate (CGR) results within 24 hours.
    - ➢ This method is applied to soil samples taken adjacent to the pipe, and is conducted in a laboratory environment.
    - ➢ The ER Probe method is considered conservative, as the resulting value does not consider the beneficial effects of cathodic protection systems in place for the pipeline under study. CGR values resulting from this test method are utilized in the “Remaining Life Calculations” (Section 11.4 of this procedure).

12.9 Linear Polarization Resistance (LPR) and Coupon applications are provided in NACE RP0502, D3.

13.0 ECDA PLAN CHANGES

13.1 Changes to the ECDA Plan, including changes that affect the severity classification, the priority of direct examination and the time frame for direct examination indications shall be communicated to all appropriate Company personnel that are involved in external corrosion direct assessment activities and to the PHMSA as required. Changes shall be processed using Procedure PS-03-01-266: “IMP Management of Change” as applicable and PHMSA notification shall be accomplished using Procedure PS-03-01-264: “IMP Communication Plan.”

14.0 ECDA RECORDS

14.1 ECDA records shall be documented to address pre assessment, indirect inspection, direct examination, and post assessment. The pertinent records in each ECDA process step are identified below.

14.2 Pre Assessment Documentation - Pre assessment steps shall be recorded. The following may be used to ensure all appropriate records are compiled and maintained:

- Data elements collected for the pipeline segments to be evaluated per Table 1
- Methods and procedures used to integrate the data collected to determine when indirect inspection tools can and cannot be used
- Methods and procedures used to select the indirect inspection tools
- Characteristics and boundaries of ECDA regions and the indirect inspection tools used in each region

14.3 Indirect Inspection Documentation - Indirect inspection steps shall be recorded. The following may be used to ensure all appropriate records are compiled and maintained:

- Geographically referenced locations of the beginning and ending point of each ECDA region and each fixed point used for determining the location of each measurement.
- Dates and weather conditions under which the inspections were conducted
- Inspection results at sufficient resolution to identify the location of each indication. When data is not recorded in a (near) continuous fashion, a complete description of the conditions between the locations of indications (epicenters) shall be recorded
- Alignment of data from the indirect inspections and expected errors for each inspection tool
- Define the criteria to be used in prioritizing the severity of the indications

14.4 Direct Examination Documentation - Direct examination steps shall be recorded in accordance with PS-03-01-242 “Dig Data Sheet.” The following may be used to ensure all appropriate records are compiled and maintained:

- Define the criteria to be used in prioritizing the indirect inspection indications

- Data collected before and after excavation
- Measured metal-loss corrosion morphology
- Data used to identify other areas that may be susceptible to corrosion
- Data used to estimate corrosion growth rates
- Results of root cause identifications and analyses
- Mitigation activities
- Description of reprioritizations

14.5 Post Assessment Documentation - Post assessment steps shall be recorded. The following may be used to ensure all appropriate records are compiled and maintained:

- Remaining life calculation results, including:
  - Maximum remaining flaw size determinations
  - Corrosion growth rate determinations
  - Method of estimating remaining life
- Reassessment intervals and scheduled activities
- Evaluation of ECDA effectiveness and results from assessments
- Feedback - Assessment of the ECDA process, and any modifications

15.0 OTHER DATA

15.1 During indirect inspection and direct examination activities other data may be discovered that may be pertinent to other threats. This data shall be used where appropriate for performing integrity assessments for other threats.

16.0 REFERENCES

16.1 Regulatory

- Department of Transportation 49 CFR Part 192

16.2 Industry Practices

- ASME B31.8
- ASME B31.8S
- NACE International Standard Recommended Practice RP0502-2002: “Pipeline External Corrosion Direct Assessment Methodology”
- NACE Standard TM0169 (guidance for coupon cleaning, corrosion rate calculations, and date reporting)

- AASHTO T 265 (for determining soil moisture content)
- EPA 376.1 (for soil sulfide ion concentration tests)
- ASTM D 1125 (for soil conductivity tests)
- ASTM D 4972 (for soil pH lab tests)
- ASTM D 512 (for soil chloride ion concentration tests)
- ASTM D 516 (for soil sulfate ion concentration tests)
- ASTM G 59 (for laboratory measurements of linear polarization resistance)
- ASTM G 102 (for calculating corrosion rate using the two electrode system)

16.3 Related Procedures and Supporting Documents

- PS-03-01-242, Dig Data Sheet Procedure
- PS-03-01-264, IMP Communication Plan Procedure
- PS-03-01-266, IMP Management of Change Procedure
- PS-03-02-200, Evaluation of Remaining Strength of Corroded Pipe Procedure
- PS-03-02-248, Close Interval Survey Procedure
- PS-03-02-250, Surface Potential Survey Procedure
- PS-03-02-254, Direct Current Voltage Gradient Survey Procedure
- PS-03-02-256, Electro-Magnetic Survey Procedure (PCM/C-Scan)
- PS-03-02-262, Guided Wave Ultrasonic Inspection Procedure
- PS-03-02-296, Bacteria Testing – Serial Dilution Method Procedure
- Book 1, O&M Procedure 200 – Abnormal Conditions

- Book 1, O&M Procedure 209 - Pipeline Locating

16.4 Forms and Attachments

- Pre-Assessment Form
- Summary of Indirect Inspection Survey Results – Direct Examination Sites

17.0 DEFINITIONS

- **Alternating Current Voltage Gradient (ACVG or A-Frame):** A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.
- **Cathodic Disbondment:** The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.
- **Cathodic Protection (CP):** A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.
- **Classification:** The process of estimating the likelihood of corrosion activity at an indirect inspection indication under typical year-round conditions.
- **Close Interval Survey (CIS):** A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.
- **Current Attenuation Survey:** A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, anomaly location, and anomaly type.
- **Defect:** An anomaly in the pipe wall that reduces the pressure-carrying capacity of the pipe.
- **Direct Current Voltage Gradient (DCVG):** A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

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

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

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

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

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

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

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

- **Indication:** Any deviation from the norm as measured by an indirect inspection tool.

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

- **In-Line Inspection:** The inspection of a pipeline from the interior of the pipe using an in-line inspection (ILI) tool. The tools used to conduct ILI are known as pigs or smart pigs.

- **Maximum Allowable Operating Pressure (MAOP):** The maximum internal pressure permitted during the operation of a pipeline.

- **Mechanical Damage:** Any of a number of types of anomalies in pipe, including dents, gouges, and metal loss, caused by the application of an external force.

- **Microbiologically Influenced Corrosion (MIC):** Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.

- **Remediation:** As used in this procedure, remediation refers to corrective actions taken to mitigate deficiencies in the corrosion protection system.

- **Sound Engineering Practice**: Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science. Associated terminology: sound engineering judgment, sound engineering analysis.

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

1.0 PURPOSE:

1.1 This procedure establishes the process for conducting a direct assessment for internal corrosion in steel pipelines that normally carry dry natural gas. This process is referred to as Dry Gas – Internal Corrosion Direct Assessment (DG-ICDA). Direct assessment is a structured process through which knowledge of the physical characteristics and operating history of a pipeline system or pipeline segment is integrated with the results of inspection, examination, and evaluation in order to determine the integrity of the pipeline.

1.2 This procedure is based on the requirements of 49 CFR 192, Subpart O (Section 192.927) and ASME B31.8S-2001, Section 6.4 and Appendix B2.

2.0 PROCESS:

2.1 The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process is a structured process for assessing the integrity of natural gas pipelines that normally carry dry gas but may suffer from short-term upsets of free water, or other electrolyte.

2.2 The basis of DG-ICDA for natural gas pipelines is a detailed examination of locations along a pipeline where an electrolyte, such as water, first accumulates, thereby providing information about the remaining downstream length of pipe. If the locations along a length of pipe that are most likely to accumulate electrolyte have not corroded, other locations less likely to accumulate electrolyte are unlikely to have suffered corrosion when operating under the same conditions. The presence of extensive internal corrosion found at many locations during application of the DG-ICDA process suggests that the transported gas was not normally dry, and therefore, the application of DG-ICDA should be reconsidered.

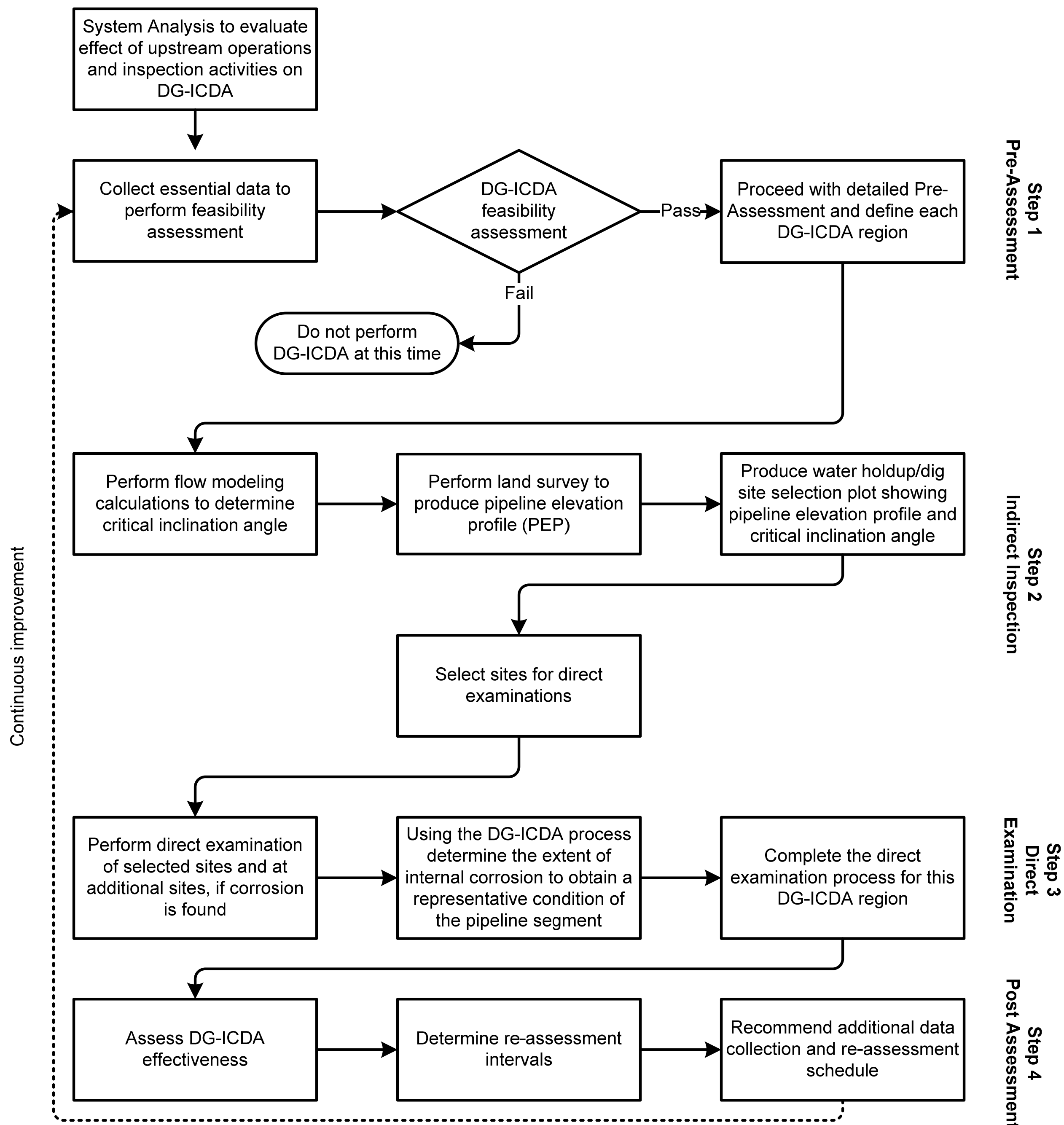
2.3 There are four primary steps in the DG-ICDA process:

- Step 1: **Pre-assessment** (system analysis, collection of supporting data, and identification of DG-ICDA Regions)
- Step 2: **Indirect Inspection** (evaluation of flow modeling data and pipeline elevation profile for the identification of excavation locations)
- Step 3: **Direct Examination** (pipeline inspection, data collection, and evaluation)

- Step 4: **Post Assessment** (DG-ICDA process results assessment and determination of process effectiveness)

2.4 DG-ICDA requires the integration of data from multiple types of field examinations and internal pipe surface evaluations, including the physical characteristics and operating history of the pipeline. A flowchart that illustrates the components of each step of the DG-ICDA Process is shown in Figure 1.

Figure 1: DG-ICDA Process Overview



3.0 PRE-ASSESSMENT (STEP 1):

3.1 The objectives of the Pre-assessment Step are to:

- Determine whether DG-ICDA is feasible for the pipeline being evaluated
- Identify DG-ICDA Regions

3.2 The Pre-assessment Step includes the following activities:

- System Analysis
- Assessment of DG-ICDA feasibility
- Data collection
- Identification of DG-ICDA Regions

3.3 System Analysis and DG-ICDA Feasibility Assessment

3.3.1 The initial step in the DG-ICDA process is to perform a System Analysis and Feasibility Assessment. This involves collecting certain operating and inspection data about the candidate pipe being considered for DG-ICDA, including adjoining pipeline systems, and completing an analysis of the data to determine whether or not DG-ICDA is feasible for the candidate pipe.

3.3.2 System Analysis is a process where the defining factors of DG-ICDA are identified. The overall purpose of the System Analysis is two-fold:

- To look at the effect that upstream operations could have on downstream DG-ICDA; and,

- To look at previously completed inspections upstream to evaluate what can be gained from this information.

3.3.3 System Analysis is an overall look at the entire system to identify: inputs, large outputs, gas quality, geographic concerns and supplier information. The main goal of System Analysis is to focus pre-assessment activities on the high consequence areas that are most susceptible to the internal corrosion threat. Components of a System Analysis may include the following:

- Study the upstream transmission system for downstream effect

- Identify all system inputs and outputs
- Identify all initial DG-ICDA regions in the system
- Collect and document gas quality
- Obtain information from suppliers (if available)
- Begin documentation necessary for the possibility of stabilizing the internal corrosion threat as well as to assist with future assessments

3.3.4 The first information required is the pipeline system configuration, which can be reviewed within pipeline maps. For the purpose of this procedural step, system pipelines are defined as any pipeline that carries the same gas to the high consequence area within the DG-ICDA candidate pipeline. This mapping exercise will show all pipe and pipe facilities that may have an influence or impact on the candidate pipe. Two items of importance can readily be determined through the system configuration study:

- Whether the pipe is directly connected to gas gathering pipelines, and thus the potential presence of high moisture content in the gas stream with the potential of causing internal corrosion.

- Whether the gas is scrubbed and/or dehydrated before entering the pipeline system, and thus a reduced likelihood of moisture in the gas stream.

3.3.5 Data to be collected for the System Analysis and subsequent Feasibility Assessment shall include the following (this data shall be collected for both the DG-ICDA candidate pipe as well as any adjoining pipelines that comprise the system identified in step 3.3.1 above):

- Data from previous In-Line Inspections (identified defects, including clock position and station location)

- Data from previous DG-ICDA assessments (identified defects, including clock position and station location)

- History of leaks caused by internal corrosion (including clock position and station location)

- Data from previous cleaning pig runs (liquids present and analysis)

- Information on corrosion inhibitor application (including dates of application, estimated volumes, and inhibitor type)

- Information concerning any corrosion monitoring devices installed (device analysis and location)

- Gas quality analysis reports (presence of O_2, CO_2, H_2O, and H_2S)

- Fluid sample analyses

3.3.6 Data is collected and used in several places in the DG-ICDA process. Table 1: “Data Elements for Consideration in DG-ICDA” identifies the various data elements and their intended use (system analysis, feasibility assessment, flow modeling, and dig sites). Data elements in Table 1 have been prioritized as “Required” or “Optional”. Required and optional data elements are defined as follows:

- Required – Data elements required to execute DG-ICDA. Any exceptions and conservative assumptions shall be documented in the event the Company elects to execute DG-ICDA where some required data elements are unavailable at the time of pre-assessment preparation. Documentation will be stored in the feasibility section of the pre-assessment document (Section 10.4 of this procedure).

- Optional – Data elements not required for execution of DG-ICDA. The Company shall make diligent effort to complete all optional data elements.

Table 1: Data Elements for Consideration in Dry Gas ICDA

DATA ELEMENT (R) = Required (O) = Optional	DESCRIPTION (Intended Use)
Water vapor (R)	Information about water vapor dew point. **(Flow Modeling)**
Pressure (R)	Typical minimum and maximum operating pressures. Preferred unit of measurement is pounds per square inch (psi gauge). **(Flow Modeling)**
Flow rate (R)	Flow rates – maximum and minimum flow rates at minimum and maximum operating pressures for all inlets and outlets, as well as high daily flow rate averaged for each month over a 12 month period (high peak demand periods must be noted and considered for prorating) Significant periods of low or no flow. Preferred unit of measurement is millions of standard cubic feet of gas per day (mmscfd). **(Flow Modeling)**
Temperature (O)	Typical average gas temperature as well as unusual operating conditions. Preferred unit of measurement is degrees Fahrenheit (˚F). **(Flow Modeling)**
External diameter (R)	Identify all locations where there is a change in OD. Combine with wall thickness to calculate internal diameter. Preferred unit of measurement is inches. **(Flow Modeling)**
Wall thickness (R)	Required to calculate internal diameter. Preferred unit of measurement is inches. **(Flow Modeling)**
Operating history (R)	Change in gas flow direction, type of service, removed taps, year of installation, etc. Has the line ever been used previously for crude oil or other liquid products? **(Pre-assessment) (evaluate upstream pipelines as part of System Analysis)**
Cleaning pig history (R)	Frequency of cleaning pig runs, including dates as well as any data from previous runs (volume and type of liquids and/or solids present and analysis) **(Pre-assessment and System Analysis)**
Defined length (R)	Length between consecutive downstream inputs/outputs **(Dig Sites)**
Elevation profile (R)	Topographical data, such as USGS data, including consideration of pipeline depth of cover. Take care in instrument selection that sufficient accuracy and precision may be achieved. Require highly accurate pipeline elevation profile if it is available, and if it is not available then it needs to be produced (refer to Appendix A). **(Dig Sites)**
Features with inclination (R)	Type and location of features (i.e., roads, rivers, drains, valves, drips, etc.) **(Dig Sites)**

DATA ELEMENT (R) = Required (O) = Optional	DESCRIPTION (Intended Use)
Inputs/outputs (R)	Must identify all locations of current and historic inputs and outputs to the pipeline including location, volume, gas composition analysis, etc. **(Dig Sites)**
Corrosion inhibitor (R)	Information about dates of injection, chemical type, and dose. **(Feasibility and Post Assessment)**
Upsets (R)	Frequency, nature of upset (intermittent or chronic), volume if known, and nature of liquid. **(Feasibility)**
ILI History (R)	Identify date of ILI runs, defects detected, including clock position and station location **(System Analysis - evaluate previously completed ILI data on upstream pipelines, Feasibility)**
DG-ICDA History (R)	Identify date of assessment, internal corrosion/defects detected, including clock position and station location, presence and volume of any water found. **(System Analysis - evaluate previously completed DG-ICDA data on upstream pipelines)**
Type of dehydration (O)	Is dehydration carried out using glycols? **(Feasibility)**
Pressure test information (O)	Date performed, past presence of water, hydrotest water quality data, results of pressure test. **(Feasibility)**
Repair/maintenance data (R)	Presence of solids, anomalies; pipe section repair and replacement; prior inspections; NDE data. Any cleaning pig locations, frequencies, and dates. Analytical data of all removed sludge, liquids when cleaning pigs were employed or from liquid separators, hydrators, etc. and the analysis performed to determine the chemical properties and corrosivity, including the presence of bacteria, of the removed products. **(System Analysis, Feasibility)**
Leaks/failures (R)	Locations and nature of leaks and failures. **(System Analysis, Feasibility)**
Gas quality (R)	Gas and liquid analyses, and any bacteria testing results for the pipeline and on shipper and delivery laterals. Relationship of gas analyses to pipe location. **(System Analysis, Feasibility)**
Corrosion monitoring (R)	Corrosion monitoring data including type of monitoring (for example, coupons, electric resistance (ER)/linear polarization resistance (LPR) probes), dates and relationship of monitoring to pipe location, corrosion rate recorded/calculated, and accuracy of data. Any available NDE inspection results. **(System Analysis, Feasibility, Post Assessment)**
Internal coatings (R)	Existence and location of internal coatings. **(Feasibility)**
Other internal corrosion data (O)	As defined by the Company **(Feasibility)**

3.3.7 As the above data is collected and reviewed, the data may provide indication of historical or active internal corrosion. The Corrosion Manager shall be notified, and will determine whether an internal corrosion monitoring program shall be initiated (that is, installation of corrosion monitoring devices such as coupons).

3.3.8 The collected data shall be reviewed to assist in determining the feasibility of the DG-ICDA process for the candidate pipeline. In addition to the System Analysis, other certain conditions may exist that preclude the application of DG-ICDA. Data shall be collected to evaluate the following conditions that are required to apply the DG-ICDA methodology:

- The pipeline has not been subjected to frequent upsets (defined herein as more than once per quarter) that could have resulted in excessive water entering the pipeline. Excessive water could lead to unexpected carryover to downstream locations where water would not normally be expected, consequently rendering the DG-ICDA process as unsuitable.

- The pipeline does not normally contain any liquids, including glycols, as excessive liquids in the pipeline may combine with any free water and consequently lead to unexpected carryover to downstream locations where water would not normally be expected.

- The pipeline has not been previously converted from a service where liquids were transported which would consequently render DG-ICDA as not applicable (for example, crude oil or petroleum products), unless it is demonstrated that internal corrosion was not evident during the previous service or that possible previous damage has been separately assessed.

- The pipeline must not have an internal coating that provides corrosion protection as the presence of an internal coating could be non-uniform and consequently lead to sporadic internal corrosion and erroneous results for DG-ICDA.

- The use of corrosion inhibitor may preclude application of the DG-ICDA process because the effectiveness of the inhibitor might not be uniform along the pipeline length. Consider data from Table 1.

- If history indicates internal corrosion at the top of the pipeline (likely due to condensed water accumulation), DG-ICDA is not applicable because this process is only suitable to detect internal corrosion that has resulted due to accumulation of water along the bottom of the pipeline. For new pipelines, the risk of top of the pipeline corrosion should be assessed by modeling or laboratory testing.

- Pigging can cause "smearing" in areas where liquids could collect, which directly affects the distribution of internal corrosion in a way not predicted by DG-ICDA. Thus, DG-ICDA may not be appropriate for pipelines that have been routinely pigged. Infrequent pigging (defined herein as less than 3 times annually) is acceptable as any smeared water pushed downstream is expected to evaporate with the gas flow and not have a significant effect on internal corrosion.

- DG-ICDA assumes uniform material properties along a pipeline segment. Consideration for differences such as weld type and geometry and material defects shall be made.

- Whether the dew point of water in the transported gas is consistently greater than 7 lbs/mmscfd.

- Pipelines that contain significant accumulations of solids, sludge or scale should not be assessed using this DG-ICDA methodology, unless the influence of those materials has been carefully evaluated. Based on the data collected in the Pre-assessment Step, it must be determined whether accumulations of solids are significant enough to influence the validity of the DG-ICDA results through any of the mechanisms described below. The presence of solids, sludge and scale may affect the validity of the DG-ICDA process by:

  – Increasing corrosion through retaining water inside a porous matrix or under a solid layer.

  – Increasing corrosion by attracting water through hygroscopic properties and/or deliquescence.

  – Increasing corrosion through the formation of a concentration cell (that is, under-deposit corrosion).

- Decreasing corrosion through the formation of a protective layer.

- Changing corrosion rates due to the influence of bacteria.

3.3.9 Figure 2 provides a Feasibility Filter flowchart for systematically determining whether the integrity of the pipeline segment can be assessed with DG-ICDA. A worksheet, such as the spreadsheet shown in Table 2, may be used for collecting the information needed to answer the questions in Figure 2.

Figure 2: DG-ICDA Feasibility Filter

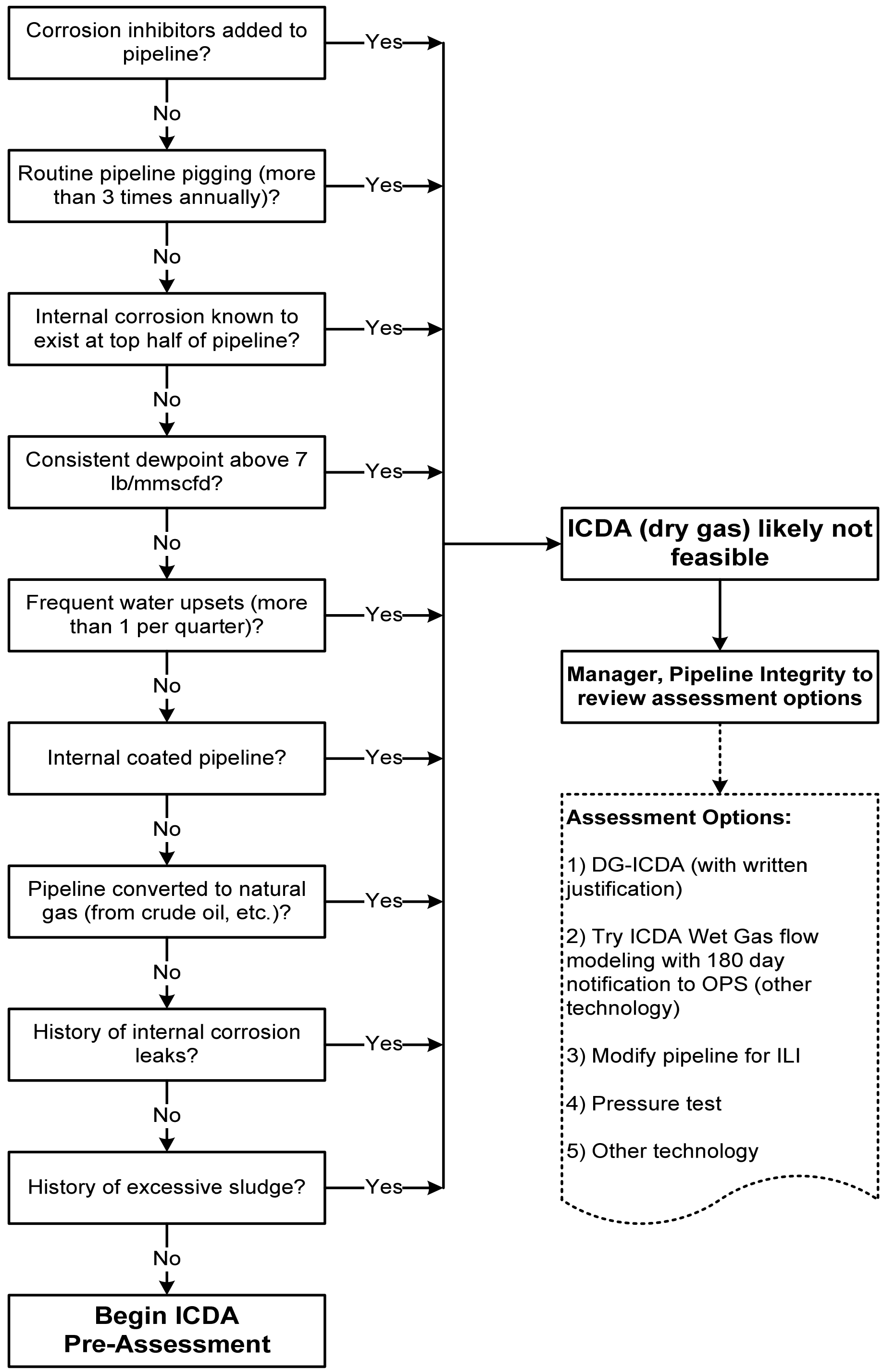


Table 2: Feasibility Filter Information Worksheet

Pipeline Data					**DG-ICDA should not be considered when:**									
Company	Line	Location	Segment/Region		Piggability*		Corrosion inhibitors added	Internal corrosion in top half of pipe	Dew point above 7 lb/mmscfd	Frequent upsets > 1 per quarter	Internal coated pipe	Pipeline converted to natural gas (from oil, etc.)	History of internal corrosion leaks	Excessive sludge in pipe
			BSTA	ESTA	ILI	Clean								

Notes for Table 2:

*Frequent running of cleaning pigs is defined as more than 3 times annually
BSTA = Beginning station
ESTA = Ending station

3.4 If DG-ICDA has been determined to be feasible for the DG-ICDA candidate pipeline segment, additional required detailed pre-assessment data shall be collected for the pipeline segment. Based on the model in NACE SP0206, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA), there are six essential data points required to perform the flow modeling that supports the DG-ICDA process:

- Dew point (water vapor)
- Gas flow rate
- Gas temperature
- Gas pressure
- Pipe wall thickness
- Pipe diameter

This data will be required to assist in establishing dig site locations for direct examination, as well as other data required to complete the DG-ICDA feasibility filter in Figure 2. Table 1, introduced in step 3.3.4 of this procedure, lists the data elements for flow modeling Company Procedure PS-03-01-239: "Dry Gas - ICDA Data Element Form" shall be used for recording collected data.

3.5 When data for a particular category is not available, conservative assumptions shall be used based on experience and information about similar systems. The basis for the assumptions shall be documented. In the event that sufficient data is not available or cannot be collected for some DG-ICDA Regions comprising a segment to support the Pre-assessment Step, DG-ICDA should not be used for those DG-ICDA Regions until the appropriate data is obtained.

3.6 Identification of DG-ICDA Regions

3.6.1 Sound engineering practice shall be used to identify DG-ICDA Regions from the data collected in the Pre-assessment Step. The criteria for identifying DG-ICDA Regions are based on the following paragraphs.

3.6.2 A DG-ICDA Region is a portion of a pipeline with a defined length. Initially, until further evaluation of the pre-assessment/indirect inspection data is performed, a defined length is any length of pipe until a new input introduces the possibility of water entering the pipe. Refer to paragraphs 3.6.5, 3.6.6, and 3.6.7 and Section 5.0: "Direct

Assessment (Step 3)" of this procedure for additional information on how the end of a DG-ICDA Region may be redefined.

3.6.3 In evaluating DG-ICDA Regions, changes in temperature and pressure shall be taken into consideration as follows:

- The critical inclination angle, discussed in the Indirect Inspection Step, at any point within a Region must be based on the local pressure and temperature at that point.

3.6.4 In the case of bi-directional flow history, DG-ICDA Regions shall be identified for each flow direction, and each DG-ICDA Region shall be treated separately.

3.6.5 All DG-ICDA Region locations shall be identified in the pipeline system in which covered pipeline segments (High Consequence Areas) are located. A DG-ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. A DG-ICDA Region may encompass one or more covered segments.

3.6.6 The beginning of a DG-ICDA Region shall only be delineated by the location of an input where water could be introduced into the DG-ICDA candidate pipeline.

3.6.6.1 An input is defined herein to include the location where there exists a feed point where gas (and possibly water) may enter the pipeline. An output or a location where water could drop out of the gas as a result of a significant drop in pressure (that is, pipe diameter increase, pressure limiting station, significant output, etc.), shall not delineate the beginning of a new DG-ICDA Region; however, these pipeline features may delineate the beginning of a new critical inclination angle.

3.6.6.2 A DG-ICDA Region shall not begin at an output (that is, delivery point or takeoff) since water cannot enter a pipeline at an output.

3.6.6.3 The beginning of a DG-ICDA Region shall begin at the first input immediately upstream of the start of the HCA.

3.6.6.4 At locations where there could be a significant change in flow parameters (an output, pipe diameter change, pressure limiting station, etc.), then the flow parameters (temperature, pressure, flow rate, etc.) shall be evaluated within the Froude equation (or a more complicated flow modeling process) to determine if there is any effect on the calculated critical inclination angle. This determination will not delineate a new DG-ICDA Region but may delineate the beginning of a pipe section with a new critical inclination angle within the DG-ICDA Region.

3.6.7 Initially, until such time as additional steps of the DG-ICDA process (that is, the Indirect Inspection and Direct Examination Steps) have been performed and evaluated, the end of the DG-ICDA Region is typically delineated by the location of the next input that exists downstream from the input that delineates the beginning of the DG-ICDA Region. However, the end of the DG-ICDA Region may be redefined (refer to Paragraph 3.6.2 above) herein as the location that coincides with the location of the second dig site (see the Direct Examination step of this procedure – Section 5.0).

3.7 DG-ICDA Pre-Assessment – More Restrictive Criteria for first time application of DG-ICDA

3.7.1. Listed below are general More Restrictive Criteria considerations. Documentation of applicable criterion (one minimum) shall be recorded in the pre-assessment document (see Section 10.4 of this procedure) under “More Restrictive Criteria”.

3.7.1.1 System Analysis: Overview of gas flow conditions from multiple inputs having an impact on specific HCAs.

3.7.1.2 Specific temperature drop and water saturation calculation method to consider pressure cuts along ICDA regions.

3.7.1.3 Coordination with local operations personnel for site visits and consultation for validation of conditions.

4.0 INDIRECT INSPECTION (STEP 2):

4.1 The primary objectives of the Indirect Inspection Step are to:

- Combine the pipeline elevation profile (that is, low points, changes in elevation, angles of inclination, etc.) with the flow-modeling results (that is, critical inclination angles).
- Predict the locations in the pipeline (for Direct Examination) that are most likely to have sustained extended water accumulation (i.e., water holdup areas) and that may have suffered internal corrosion within each DG-ICDA Region.

4.2 The Indirect Inspection Step relies on the ability to identify locations most likely to accumulate electrolyte and is applicable to pipelines in which stratified film flow is the primary liquid transport mechanism.

4.3 The Indirect Inspection Step shall include the following activities for each DG-ICDA Region:

- Perform multiphase flow modeling calculations using collected data to determine the critical inclination angle expected to cause liquid holdup.
- Produce a pipeline elevation profile to determine low points and angles of inclination that exist within the pipeline.
- Identify sites for Direct Examination where internal corrosion may be present (caused by water holdup) by integrating and evaluating the flow modeling results with the pipeline elevation profile.

4.4 Flow Model Calculations

4.4.1 Determining expected locations for water accumulation shall be predicted using flow modeling calculations for each identified DG-ICDA Region. Any multiphase flow modeling approach valid for small liquid volumes is acceptable. In principle, the simplified flow modeling approach used in this procedure may be applied to all systems with stratified flow.

4.4.2 The Critical Inclination Angle is the calculated angle of the pipe's inclination at which electrolyte would not be expected to flow downstream in the pipe (that is, the gravitational forces acting on the electrolyte are greater than the shear stresses of the gas flowing downstream). Electrolyte (that is, water) is predicted to flow beyond an uphill slope when the pipe inclination is less than the Critical Inclination Angle, but not to flow beyond the uphill slope when the pipe inclination is greater than the Critical Inclination Angle.

For example: The Critical Inclination Angle may be calculated to be 5°. If the angle of pipe inclination is less than 5°, then any water present would be expected to flow downstream since the pipe angle is less than the Critical Inclination Angle. If the angle of pipe inclination is 5° or greater, then water would not be expected to flow downstream since the pipe inclination angle is greater than critical. Any electrolyte present within the pipeline is expected to accumulate at the onset of the Critical Inclination Angle (or slightly downstream, depending on the flow rate of the gas).

4.4.3 A simple method (known as the Froude equation) to predict the critical inclination angle, θc, utilizes a correlation obtained between sin (θ) and the ratio of gas inertia force to liquid gravitational force, which combines results of simulations in the following expression, Equation (1):

$$\theta_c = \arcsin\left(0.675\,\frac{\rho_g}{\rho_l - \rho_g} \times \frac{V_g^2}{g \times d_{id}}\right)^{1.091} \qquad (1)$$

Where:
θ_c = Critical inclination angle (in degrees)
ρ_l = Liquid density
ρ_g = Gas density (determined by total pressure and temperature)
g = Acceleration due to gravity
d_{id} = Internal diameter
V_g = Superficial gas velocity (V_g = Q/A = flow rate / internal cross-sectional area of the pipe)

The units of gas and liquid density must be the same, and the units for velocity, gravitational constant, and diameter must be consistent and compatible.

Note: The flow rate used in the V_g calculation above shall be the operational flow rate for the normal high flow day in a calendar month (units MCF/D) for any given 12-month period. The pressure and temperature for the same normal high flow day shall also be used.

When using the data and calculations provided in Figure 3 (see section 4.4.5), a Compressibility Factor, Z, shall also be considered. The gas compressibility factor is the ratio of the actual volume of a given mass of gas at a specified temperature and pressure to its volume calculated from the ideal gas law under the same conditions. This factor is represented in the following expression, Equation (2):

$$Z = \frac{PV}{nRT} \qquad (2)$$

Where (units based on Standard International):

Z = Compressibility factor (unitless)

P = Pressure (in psi gauge)

V = Volume (cubic feet)

n = Number of Moles (pounds/lb-mole)

R = The gas constant (10.7316 psia.ft^3/(lb mol•˚R))

T = Temperature (in degrees Rankin (°R))

For the range of typical DG-ICDA conditions for natural gas, Z = 0.83 shall always be used. This is the compressibility factor for methane, the primary constituent of natural gas, at normal ranges of operating temperatures and pressures. If the DG-ICDA candidate pipeline is not carrying natural gas, then the Compressibility Factor will need to be re-calculated.

4.4.4 The combination of process parameters (that is, pressure, temperature, and superficial gas velocity) to which the pipeline has been exposed over its operational history, shall be used for the DG-ICDA flow calculations.

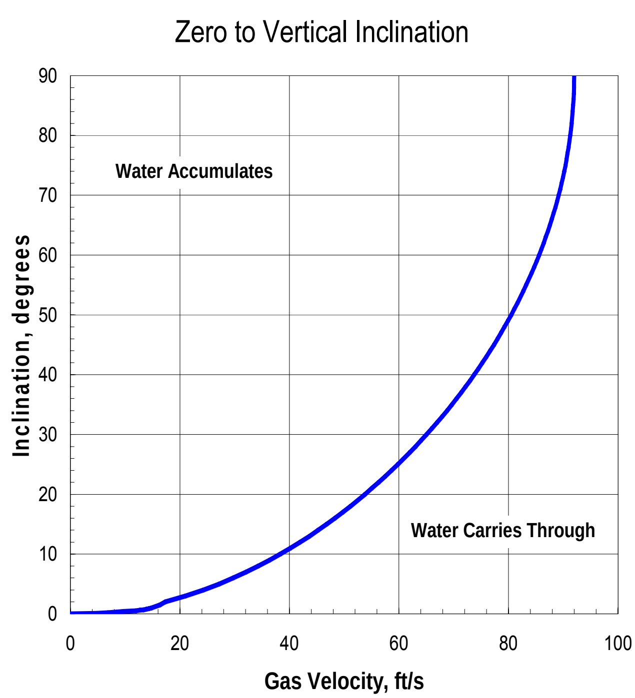
4.4.5 The critical inclination angle may be calculated using a computerized spreadsheet such as the sample shown in Figure 3.

Figure 3: Critical Inclination Angle Calculator
Holdup Predictor (based on gas velocity)

Input items in red to calculate the critical angle for water holdup:

Pipe Size I.D., Inches	Pressure, psi	Temperature, F
8	**600**	**60**

***Based on detailed modeling results within the range of 4 to 48 inch I.D., 500 to 1100 psi, 60 to 120F, and 0 to 25 ft/s gas velocity**



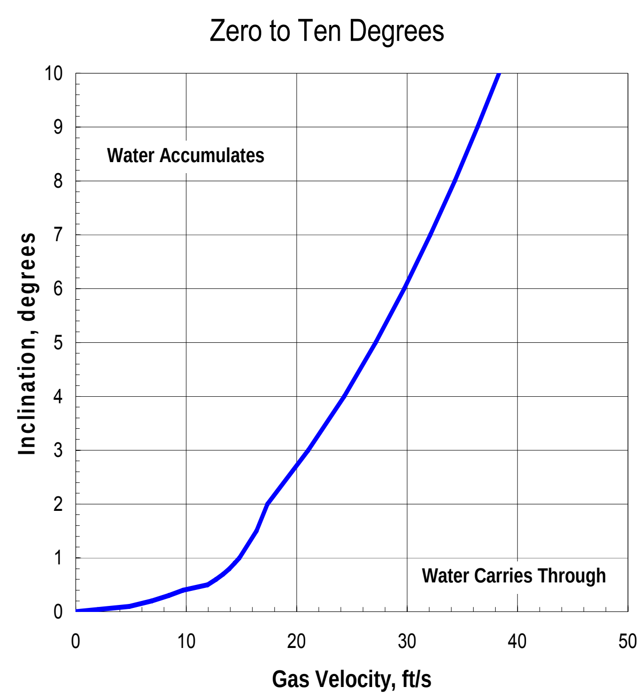
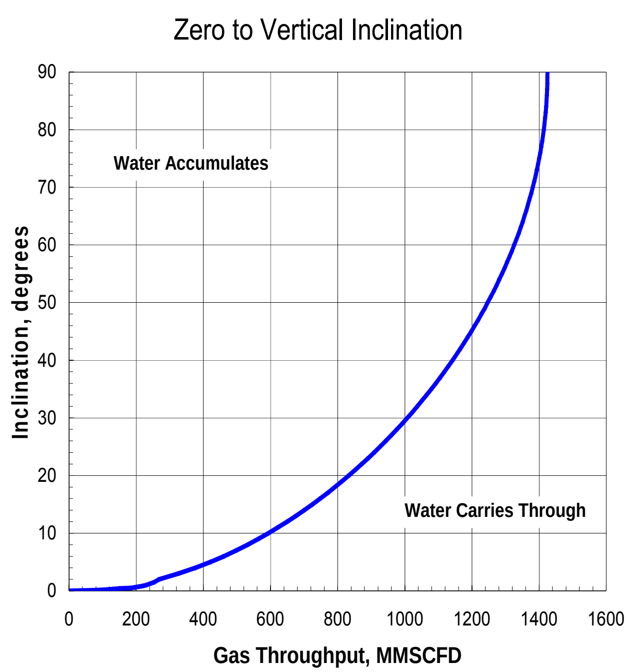


Figure 3: Critical Inclination Angle Calculator (Cont'd) (based on gas flow rate, in MMSCFD)

Items to calculate the critical angle for water holdup input on Main Sheet:

Pipe Size I.D., Inches	Pressure, psi	Temperature, F
8	**600**	**60**

***Based on detailed modeling results within the range of 4 to 48 inch I.D., 500 to 1100 psi, 60 to 120F, and 0 to 25 ft/s gas velocity**



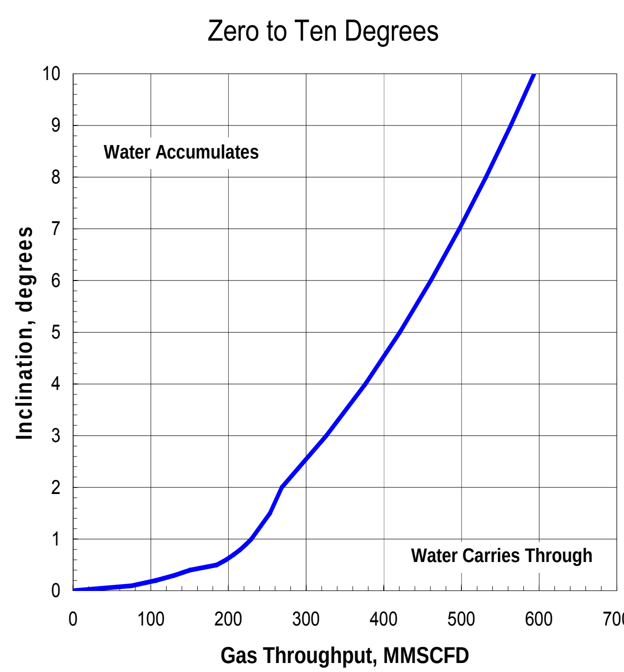


Figure 3: Critical Inclination Angle Calculator (Cont'd)
Calculations

Angle	Velocity, ft/s	MMCF/d @hp	MMSCF/d
0	0	0	0
0.1	1	0	2
0.2	2	0	3
0.3	2	0	3
0.4	3	0	4
0.5	4	0	7
0.6	5	0	7
0.7	5	0	8
0.8	5	0	8
0.9	5	0	8
1	6	0	8
1.5	6	0	9
2	7	0	10
3	7	0	11
4	8	0	13
5	9	0	14
6	10	0	15
7	11	0	17
8	12	0	18
9	12	0	19
10	13	0	20
11	14	0	21
12	14	0	22
13	15	0	23
14	15	0	24
15	16	0	24
16	17	0	25
17	17	1	26
18	17	1	27
19	18	1	27
20	18	1	28
21	19	1	29
22	19	1	29
23	20	1	30
24	20	1	30
25	20	1	31
26	21	1	32
27	21	1	32
28	22	1	33
29	22	1	33
30	22	1	34
31	23	1	34
32	23	1	35
33	23	1	35
34	24	1	36
35	24	1	36
36	24	1	37
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38	25	1	37
39	25	1	38
40	25	1	38
41	25	1	39
42	26	1	39
43	26	1	39
44	26	1	40
45	26	1	40
46	27	1	41
47	27	1	41
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49	27	1	42
50	28	1	42
51	28	1	42
52	28	1	42
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66	30	1	46
67	30	1	46
68	30	1	46
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78	31	1	47
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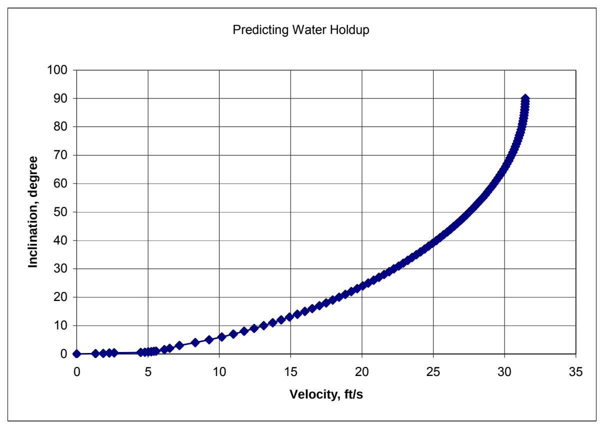
80	31	1	47
81	31	1	47
82	31	1	48
83	31	1	48
84	31	1	48
85	31	1	48
86	31	1	48
87	31	1	48
88	31	1	48
89	31	1	48
90	31	1	48

Parameters in Blue are Input in Predictor Sheet
Parameters in Red are Adjustable

ID =	**8** Inch	
P =	**600** psi	Gauge
T =	**60** deg F	
rho(liquid) =	**1** g/cm^3	Specific Gravity of Water
rho(gas) =	3.11E-02 g/cm^3	Ideal Gas Law assuming Methane and Compressibility Factor
g =	32.17 ft/s^2	
F =	0.675 (for >2 degree)	
F =	0.675 (for 0.5>theta>2 degree)	
F =	0.675 (for <0.5 degree)	
Compressibility	**0.83**	



4.5 Pipeline Elevation Profile

4.5.1 The pipeline elevation (changes in elevation over the defined pipeline length) shall be calculated using the collected pipeline data. In order to evaluate very small changes in inclination that are necessary to apply the principles of DG-ICDA, the pipeline elevation profile (PEP) requires a very high level of accuracy.

4.5.2 The elevation profile shall be composed of multiple sets of data points for each DG-ICDA Region examined and shall be calculated by Equation (3):

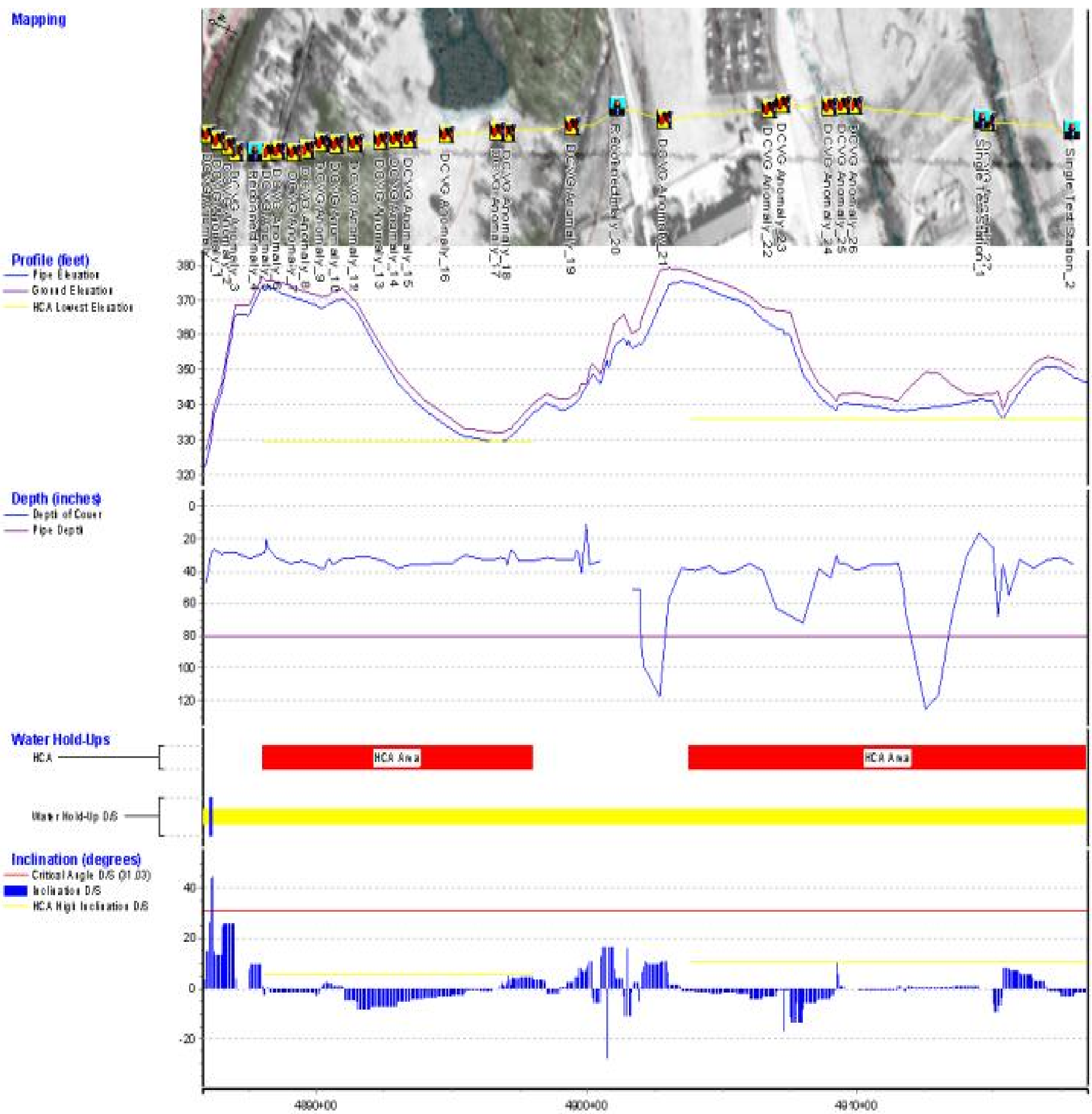
$$\theta_i = arcsin\left(\frac{\Delta(elevation)}{\Delta(distance)}\right) \tag{3}$$

Where:

θ_i = Inclination angle (degrees)
Δ(elevation) = elevation change (feet)
Δ(distance) = distance change (feet)

4.5.3 Elevation measurements shall be taken at intervals that capture all relevant changes in the elevation profile. The minimum interval depends upon the specific pipeline being evaluated, the terrain, and other features. Uncertainty in the inclination profile must be estimated based on the accuracy of elevation data. The process for collecting the pipeline elevation profile, the elevation data obtained, and assumptions made in the process are detailed in Appendix A of this procedure. The following Figure 4 is a sample of a DG-ICDA Water Holdup/Dig Site Selection Plot that is produced by combining the pipeline elevation profile with the calculated value of the critical inclination angle. The DG-ICDA Water Holdup/Dig Site Selection Plot has the capability to show an aerial photograph of the DG-ICDA Region, pipeline features, pipeline elevation profile, water hold up areas, the location of High Consequence Areas (HCAs), and the calculated critical inclination angle. The DG-ICDA Water Holdup/Dig Site Selection Plot is produced for each DG-ICDA Region using a commercial software package such as Proactive Software by MCMiller.

Figure 4: Sample DG-ICDA Water Holdup/Dig Site Selection Plot



4.6 Direct Examination Dig Site Selection - General

4.6.1 Direct Examination dig sites at which water holdup/internal corrosion may be present shall be determined by integrating the flow modeling results with the pipeline elevation profile. Site selection should include consideration of sags, drips, dead legs, traps, etc. and inclination angles at road crossings, rivers, drainage ditches, and other locations.

4.6.2 The DG-ICDA Water Holdup/Dig Site Selection Plot can be used to identify possible internal corrosion sites where liquid holdup could occur based on the comparison of the critical angle calculations with the elevation profile (pipe inclination) results.

4.6.3 If there has been bi-directional flow through the pipeline, pipe inclinations for the opposite direction shall be considered as separate DG-ICDA Regions, and each direction shall be handled separately.

4.6.4 Water accumulation is expected to occur internally within pipelines at the onset of critical inclination angles (or slightly downstream).

4.7 Direct Examination Dig Site Selection - Specific

4.7.1 If collected data include information about the period of time a pipeline experienced velocity ranges, the significance of the ranges using flow modeling or equivalent shall be evaluated.

4.7.2 A minimum of two locations shall be identified for direct examination within each DG-ICDA Region.

4.7.3 The first location (Dig Site #1) shall be the low point (for example, sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the DG-ICDA Region.

4.7.3.1 The low point shall be defined as the first downstream low point within the covered segment nearest to the beginning of the DG-ICDA Region where water would be expected to accumulate. The location of a low point is considered to be the lowest point in elevation that exists between an upstream decline and a downstream incline.

4.7.3.2 The purpose of direct examining this location is to inspect for internal corrosion that could result from water accumulation under low gas flow conditions.

4.7.4 The second location (Dig Site #2) shall be further downstream, within a covered segment, near the end of the DG-ICDA Region. Note that the end of a DG-ICDA Region is initially delineated by the location of the next downstream input; however, the end of the DG-ICDA Region can be relocated based on the following approach to binding the extent of internal corrosion within this section of pipeline.

4.7.4.1 The end of the DG-ICDA Region may be redefined as the location that coincides with the location of the second dig site. The second dig site shall be downstream of the first dig site at the location of the next downstream critical inclination angle that occurs within this or any subsequent downstream covered segment. The location of the critical inclination angle shall be determined based on equations (1) and (2) in this procedure.

4.7.4.2 If there is no critical inclination angle downstream of the first dig location, within this or any subsequent downstream covered segment, then the second dig location shall be at the largest angle of inclination that exists downstream of the first dig site, but within this or any subsequent downstream covered segment within the DG-ICDA Region. Note that if there is no critical inclination angle in any of the covered segments, then evaluate all of the downstream covered segments within the DG-ICDA Region and select the largest angle of inclination that occurs.

4.7.4.3 The purpose of direct examining the second dig site is to inspect for internal corrosion that would be expected to occur as the result of water accumulation and extended dwell time under high gas flow conditions.

4.7.5 The overall objective of the dig site location selection is to “bind” the extent of anticipated water accumulation and internal corrosion within the DG-ICDA Region based on both low and high gas flow conditions.

4.7.6 In many cases the DG-ICDA Region may contain only one or a couple of covered segments as the length of the DG-ICDA Region will be bound by the length of pipeline that exists between the first and second dig sites. Typically, the second dig site at the next downstream critical inclination angle (or the largest angle of inclination in any downstream covered segment if no critical inclination angle exists) would be expected to occur downstream in relatively near proximity to the upstream low point (that is, the first dig site). Due to the close proximity expected between the two dig sites (that is, the overall length of the DG-ICDA Region), it is expected that only one or very few covered segments will actually exist within the DG-ICDA Region.

4.7.7 In some cases, such as when there exists a critical inclination angle immediately downstream from the first dig site (the low point encountered) and when dig site #1 and #2 may be within one dig location, an engineering assessment may be implemented to determine an additional dig site location and/or a more reasonable dig site location.

4.8 DG-ICDA Indirect Inspection – More Restrictive Criteria for first time application of DG-ICDA

4.8.1. Listed below are general More Restrictive Criteria considerations. Documentation of applicable criterion (one minimum) shall be recorded in the pre-assessment document (see Section 10.4 of this procedure) under “More Restrictive Criteria”.

4.8.1.1 Proprietary software computer program application to accurately calculate the critical inclination angle and graphically integrate pipeline elevation profile, low points and critical inclination angles with aerial photography display.

4.8.1.2. Pipeline Elevation Profile Process: Land surface elevation survey (GPS/RTK) conducted concurrently with depth-of-cover survey (electronic pipe location/depth instrumentation) to produce accurate pipeline elevation profile data.

5.0 DIRECT EXAMINATION (STEP 3):

5.1 The primary objectives of the Direct Examination step are to:

- Determine if internal corrosion exists at the Direct Examination dig site locations that were selected in the Indirect Inspection step. Note that the existence of “internal corrosion” is defined herein as meaning significant internal corrosion resulting in a detected loss in pipeline wall thickness of at least 10% of the nominal pipe wall thickness.

- Use the findings to assess the overall condition of the DG-ICDA Region.

5.2 Flowcharts for the Direct Examination step are shown in Figures 5A, 5B, and 5C. Figure 5A describes the process for the minimum two direct examinations required. Figure 5B describes the additional examination process if corrosion is found. Figure 5C describes the sub-region evaluation process.

Figure 5A: Direct Examination Process
Minimum Two Dig Locations

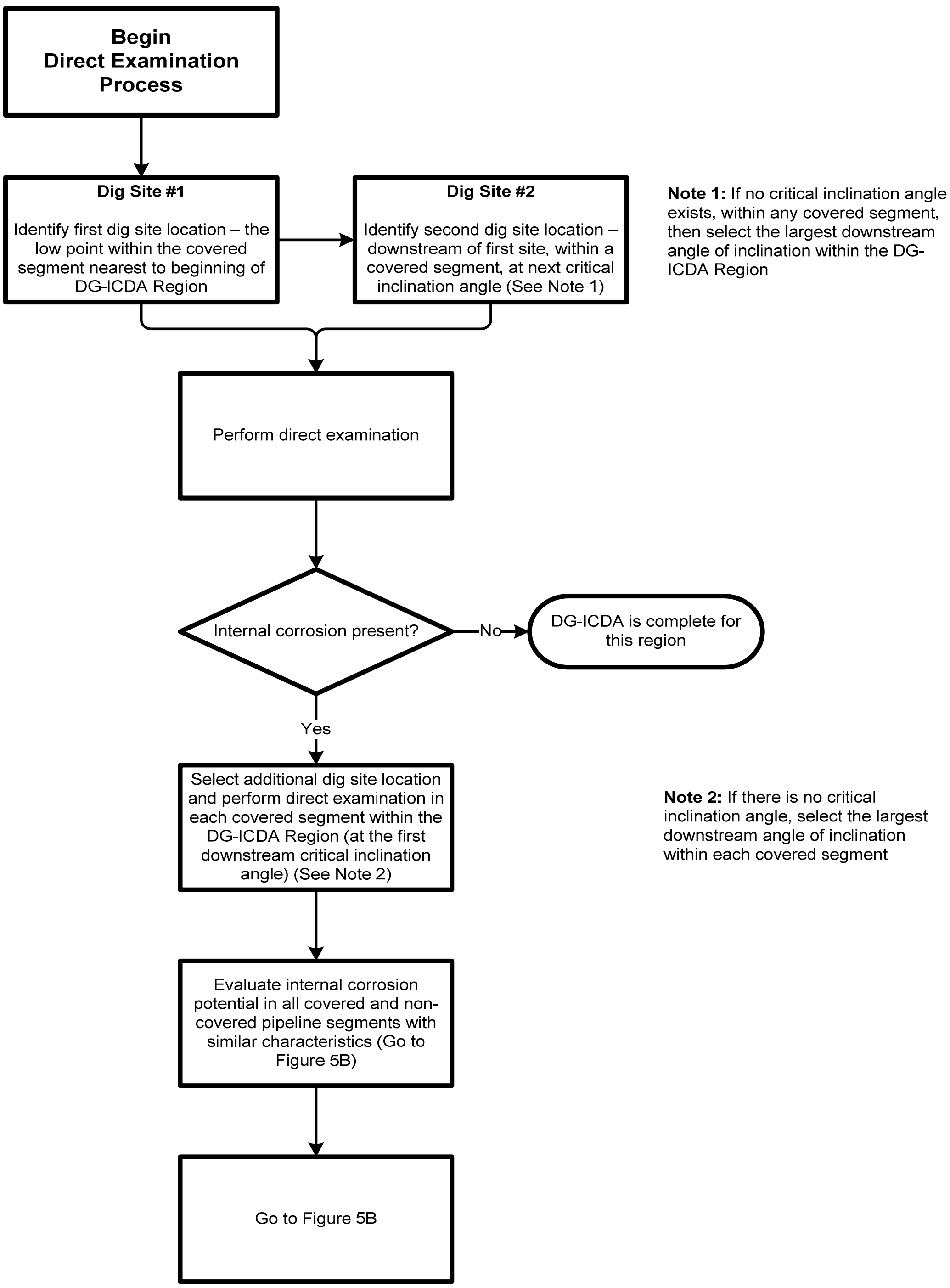
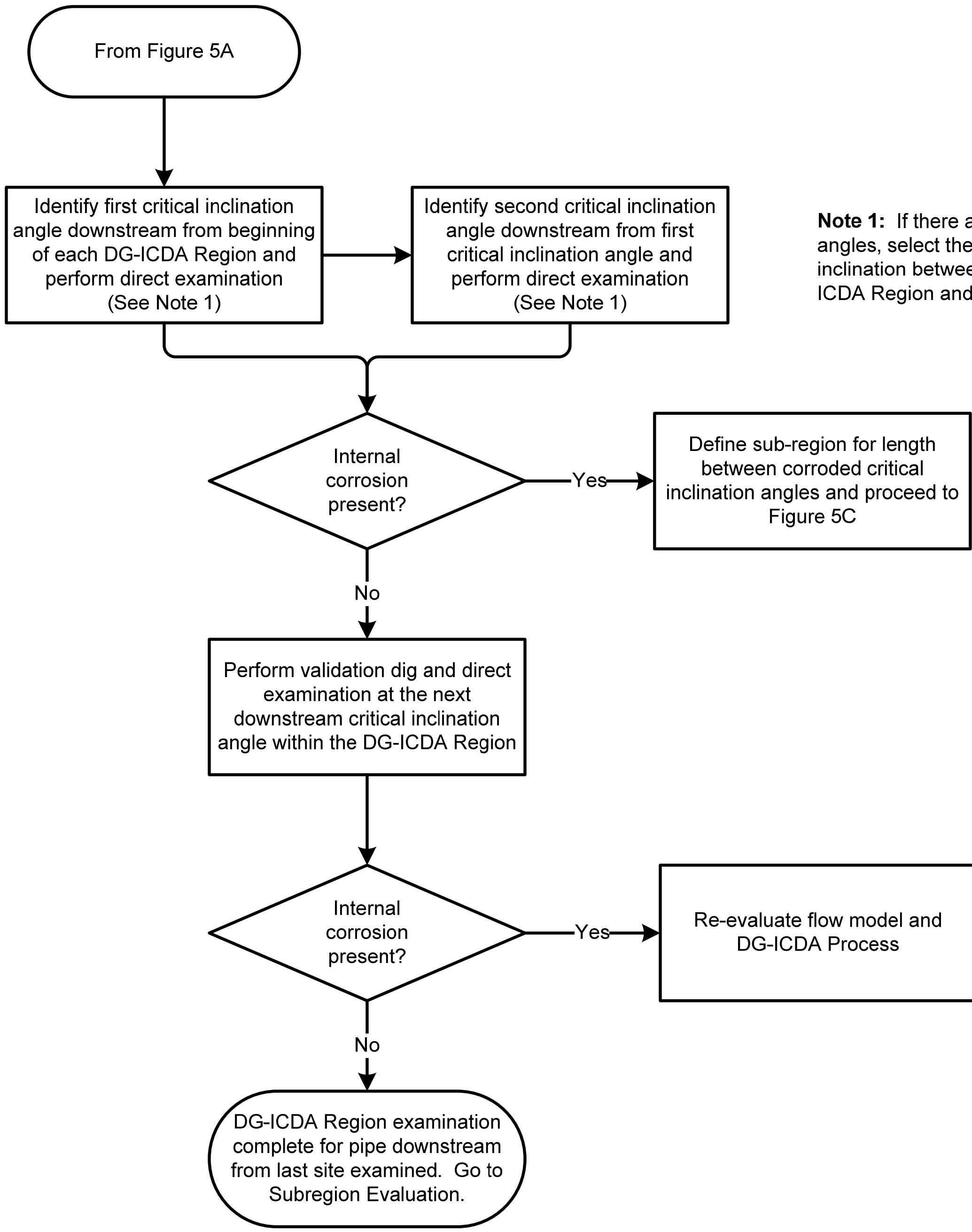


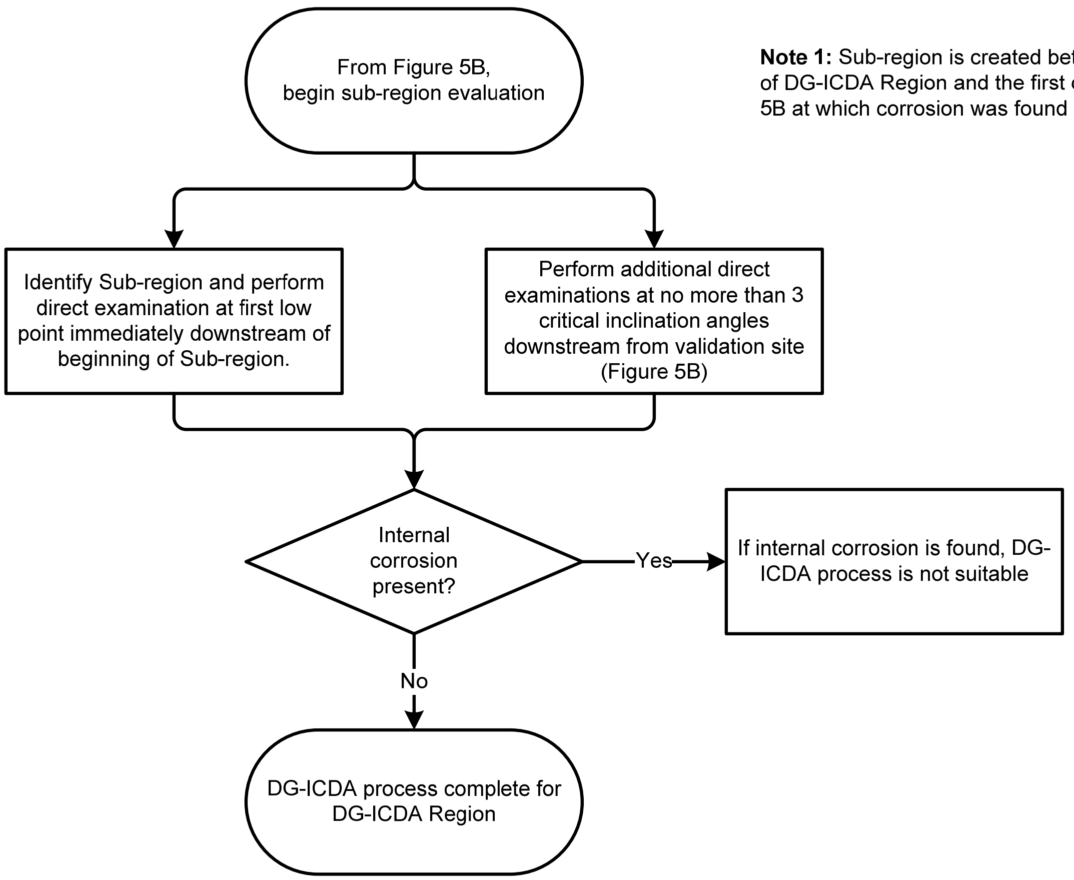
Figure 5B: Direct Examination Process
Pipeline Segments with Similar Characteristics



Note 1: If there are no critical inclination angles, select the next largest angle of inclination between the beginning of the DG-ICDA Region and the location of Dig Site #1.

Figure 5C: Direct Examination Process Sub-region Evaluation

Note 1: Sub-region is created between beginning of DG-ICDA Region and the first dig site in Figure 5B at which corrosion was found



5.3 The priority in which excavations and direct examinations are made shall be determined by a comparison of flow modeling results with the pipe elevation profile.

5.4 **Two minimum required dig sites** - A minimum of two direct examinations are required within a covered segment within each DG-ICDA Region (refer to steps 4.7.3 and 4.7.4 of this procedure). (Refer to 49 CFR Part 192 Subpart O Paragraph 192.927 (c) (3)).

5.5 **Additional Direct Examinations – Covered Segments** - If internal corrosion is found at either of the two minimum required dig sites identified in the Indirect Inspection Step (steps 4.7.3 and 4.7.4), then additional direct examinations are required (or an alternative assessment method shall be used, to determine the extent of internal corrosion in the pipe in each covered segment within the DG-ICDA Region). The extent of internal corrosion shall be determined by performing at least one direct examination in each covered segment within the DG-ICDA Region. The Direct Examination shall be performed at the first downstream critical inclination angle that occurs within each of the covered segments that exists within the DG-ICDA Region (Refer to 49 CFR Part 192 Subpart O Paragraph 192.927(c) (3) (ii)).

5.5.1 Since each DG-ICDA Region may only contain one or a couple of covered segments, as the length of the DG-ICDA Region is bound by the length of pipeline that exists between the first and second dig sites identified in the Indirect Inspection Step, there may only be a small number of digs required to assure the integrity of the pipeline and meet the intent of the regulations.

5.5.2 If there is no critical inclination angle within each covered segment within the DG-ICDA Region, then at least one direct examination shall be performed at the largest angle of inclination that exists within each covered segment within the DG-ICDA Region.

5.5.3 If there is only one covered segment within the DG-ICDA Region, the additional dig shall be performed at the next downstream critical inclination angle within the covered segment. Again, if there is no critical inclination angle within the covered segment, then the dig shall be performed at the largest angle of inclination that occurs within the covered segment.

5.6 **Additional Direct Examinations – All Pipeline Segments -** If internal corrosion is found at either of the two minimum required dig sites identified in the Indirect Inspection Step (steps 4.7.3 and 4.7.4), the Internal Corrosion Project Manager will be notified in writing and the potential for internal corrosion in all pipeline segments (both covered and non-covered) with similar characteristics to the DG-ICDA Region containing the covered segment in which the corrosion was found, shall also be evaluated, based on the following (Refer to 49 CFR Part 192 Subpart O Paragraph 192.927 (c) (3) (iii)):

5.6.1 Additionally, as a minimum, direct examination digs shall be performed at the first two critical inclination angles that occur downstream from the beginning of each DG-ICDA Region with the pipeline segment. If corrosion is not found at these two additional dig sites, then one more validation dig shall be performed at the next downstream critical inclination angle within the DG-ICDA Region. If no internal corrosion is found at these three locations, then the extent of internal corrosion can be assumed and no further direct examinations will be necessary.

5.6.2 **Sub-region evaluations -** If corrosion is found at any of the three additional dig locations identified above (paragraph 5.6.1), then:

5.6.2.1 A sub-region shall be created between the beginning of the DG-ICDA Region and the first dig site location identified in paragraph 5.6.1 where corrosion was found. One direct examination dig shall be performed at the first low point that occurs immediately downstream of the beginning of the DG-ICDA sub-Region.

5.6.2.2 Additional direct examination digs shall be performed at no more than three subsequent critical inclination angles immediately downstream from the validation dig site identified in paragraph 5.6.1. If corrosion is found at any one of these three additional direct examination dig sites, the direct examination and DG-ICDA process shall be discontinued as finding corrosion at any one of these locations means that water has passed beyond several critical inclination angles within the DG-ICDA Region and therefore the DG-ICDA process is not suitable.

5.6.3 If no internal corrosion is found at the locations identified in paragraphs 5.6.1 or 5.6.2, then the extent of internal corrosion can be assumed and no further direct examinations will be necessary.

5.6.4 If engineering assessment determines that the evidence collected during the direct examination process indicates that DG-ICDA is not suitable, or if the presence of water/internal corrosion appears to be widespread, the Manager, Pipeline Integrity should determine whether to discontinue with the DG-ICDA process or to consider an alternative assessment method or remediation action.

5.7 Performing the Direct Examination Process

5.7.1 The Direct Examination step focuses on examination efforts by physically inspecting selected sites and features along the pipeline that have been identified by the Indirect Inspection process as being most likely to contain internal corrosion. Excavation and subsequent inspection, sufficient to identify and characterize internal corrosion features in the pipe, shall be used, based on the following:

5.7.2 The following are acceptable industry methods for performing the Direct Examinations and evaluations. Any of the following may be used, as well as any other technology that becomes approved for use by the Department of Transportation. Nondestructive testing (NDT) methods used to determine the remaining wall thickness of the pipe in corroded areas shall be performed in accordance with written procedures by individuals qualified with the training and experience required by the Company. One or more of the following nondestructive testing methods shall be used to determine whether corrosion is present and the remaining pipe wall thickness:

- Ultrasonic Inspection – Wall Thickness Measurements
- Radiography

- Guided Wave Technology Nondestructive Screening

5.7.3 When performing the direct examination, conduct detailed, accurate measurements of the pipe wall thickness and determine the axial length and width of any wall loss indications present (that is, internal corrosion mapping). It is imperative that the minimum wall thickness values within the wall-loss areas be identified. The length of the pipeline affected by water accumulation may be large in some situations, and care should be taken in selecting the proper NDT technique.

5.7.4 During the Direct Examination step, defects other than internal corrosion may be found. While defects such as external corrosion, mechanical damage, and stress corrosion cracking may be found, alternative methods must be considered for assessing the impact of such defect types. The presence of external corrosion must be taken into account when measuring wall thickness, particularly in cases when internal corrosion happens to coincide with external corrosion.

5.7.5 A Dig Data Sheet, which is used to record all pertinent soil and environmental information, shall be prepared for each excavation. Refer to Company Procedure PS-03-01-242: “Dig Data Sheet.”

5.8 The remaining strength of the pipe at locations where corrosion is found shall be calculated. Acceptable methods for calculating remaining strength are ASME B31G and RSTRENG (Refer to Company Procedure PS-03-02-200: “Evaluation of Remaining Strength of Corroded Pipe”).

5.9 Corrosion found at any of the Direct Examination sites requires the following (refer to Paragraph 5.1 through 5.6 for further details when internal corrosion is found):

- Evaluation of the severity of the defect and remediation
- Perform additional excavations or use alternative assessment methods
- Notify the Internal Corrosion Project Manager in writing
- Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) with similar characteristics to the

DG-ICDA Region containing the covered segment in which the corrosion was found, and, as appropriate, remediate the conditions found.

5.9.1 Remediation shall be performed in accordance with PS-03-01-250: “Pipeline Evaluation and Remediation”, and PS-03-01-252: “Schedule of Repair Requirements”.

5.10 Once a dig site has been excavated and the Direct Examination activities have been completed, corrosion monitoring devices such as a coupon, electronic probe, ultrasonic sensor, or electrical resistance matrix may be installed. The Corrosion Manager shall determine whether or not to install a corrosion monitoring device and the appropriate location within the DG-ICDA Region. Company procedure PS-03-02-294: “Internal Corrosion Coupons” provides additional information about the installation of corrosion monitoring devices and Company procedure PS-03-02-001: “Corrosion Control Program” provides additional information on the Company’s internal corrosion control program.

5.12 If the locations most susceptible to internal corrosion due to the presence of water accumulation are found to be free from metal loss, the integrity of a large portion of pipeline mileage has been assured relative to the internal corrosion threat.

5.13 Acceptable repair methods of pipeline defects shall be performed in accordance with Company procedures PS-03-01-250: “Pipeline Evaluation and Remediation”, PS-03-01-254: “Threat Prevention and Repair Chart”, and Book 1, Manual of Operating & Maintenance, Specification 226: “Pipeline Repairs - Existing In Service Pipelines”.

5.14 DG-ICDA Direct Examinations – More Restrictive Criteria for first time application of DG-ICDA

5.14.1 Listed below are general More Restrictive Criteria considerations. Documentation of applicable criterion (one minimum) shall be recorded in the pre-assessment document (see Section 10.4 of this procedure) under “More Restrictive Criteria”.

5.14.1.1 Utilize Long Range Guided Wave Ultrasonic technology as a screening tool to assist in identifying locations for application of in-depth NDT evaluation for evidence of internal corrosion.

5.14.1.2 Comprehensive direct examination information package including: Dig data sheet, GUL report, UT grid data, laboratory chemistry test data, MIC analysis, photographs, and sufficient information to populate a pipe inspection report.

5.14.1.3 External applications of more restrictive criteria for DG-ICDA dig sites:

A. Complete soil chemistry and MIC analysis, soil resistivity and pipe-to-soil potential measurements for all DG-ICDA dig sites.

B. Additional testing utilizing NDT methods (i.e., magnetic particle, liquid penetrant, ultrasonic, etc.) are conducted on suspect conditions (i.e., suspect girth welds, longitudinal seams, and stress risers resulting from dents or third party damage) that demand further examination.

6.0 POST ASSESSMENT (STEP 4):

6.1 The primary objectives of the Post Assessment Step are to:

- Assess the effectiveness of DG-ICDA
- Determine continued monitoring requirements and reassessment intervals.

6.2 Assessment of DG-ICDA effectiveness

6.2.1 The effectiveness of the DG-ICDA process is determined by evaluating the correlation between (a) and (b), as follows:

a. The locations and extent of detected water holdup/internal corrosion that was actually found by the Direct Examination process; and,

b. The locations that were predicted by the DG-ICDA Indirect Inspection process as expecting to have water holdup/internal corrosion.

6.2.1.1 Evaluation of the effectiveness of the DG-ICDA process is essentially a subjective exercise; however, the following mathematical approach may be used as an aid in evaluating effectiveness.

- Generally, if water holdup/internal corrosion is found to exist ONLY within the pipeline at the majority (that is, more than or equal to 50%) of the Direct Examination dig sites that were predicted by the Indirect Inspection process to have water holdup/internal corrosion (for example, 3, 4, 5, or 6 of 6 dig sites), then the DG-ICDA process is considered to be **effective**.

- Conversely, if water holdup/internal corrosion is not found to exist within the pipeline at the majority (that is, less than 50%) of the Direct Examination dig sites that were predicted by the Indirect Inspection process to have water holdup/internal corrosion (for example, 0, 1, or 2 of 6 dig sites), or if water/internal corrosion is found at other non-predicted locations, then the DG-ICDA process may be considered to be **ineffective**. However, if no water holdup is found as predicted, then the introduction of water into the pipeline may never have occurred, and the DG-ICDA process may still be considered to be **effective**.

6.2.1.2 Improvements as a result of this assessment shall be incorporated into future internal corrosion direct assessments.

6.2.2 If extensive internal corrosion is found widespread throughout the pipeline (indicating significant amounts of water present within the pipeline), or if significant internal corrosion is found at the inside top of the pipe (indicating a high level of condensation collecting on the inside surfaces of the pipeline), the assumption of normally dry gas shall be reevaluated. If this is the case, then the pipeline is considered to carry wet gas and DG-ICDA is not suitable. This will mean that one or more new assessment techniques must be performed (for example, in-line inspection, pressure testing, or other technology suitable for wet gas) to evaluate the nature and extent of the internal corrosion.

6.3 Internal Corrosion Growth Rate Estimation

6.3.1 If no internal or external corrosion defects are found, then the remaining life of the pipe is the same as for new pipe.

6.3.2 If corrosion is found, the largest, non-unique defect found during the Direct Examination Step shall be used as the remaining flaw size.

6.3.3 The lifetime corrosion rate information for the site examined is desirable and can be determined from direct measurement of wall thickness and as a function of time. Wall loss data may be available by employing one of the following methods:

- Reexamine the inspection site at a prescribed frequency to determine or assess growth rate (that is, monitor the site for internal corrosion growth on the actual pipe).
- Install one or more corrosion monitoring devices at sites of predicted liquid accumulation based on flow modeling results, and/or at other representative locations.
- Collect and analyze gas and liquid samples at required intervals.
- Apply a corrosion growth rate model based on operating conditions, gas quality, liquid composition, and other key factors. Until such time as an Internal Corrosion Control Program can be implemented and/or internal corrosion monitoring devices can accurately determine the internal corrosion rate, a default value of 16 mils per year may be selected to assist in determining remaining life.

> **NOTE:**
> The Internal Corrosion Project Manager is responsible for determining whether corrosion monitoring devices shall be installed and the appropriate installation location.

6.4 Determination of Remaining Life and Reassessment Intervals

6.4.1 The remaining life is calculated by subtracting the minimum wall thickness (based on pipe material specifications and as required to pass ASME B31G) from the measured remaining wall thickness. This value is divided by the corrosion rate calculated previously to determine remaining life.

6.4.2 DG-ICDA reassessment intervals are then set to ½ of the remaining life calculated in step 6.4.1.

6.4.3 The selected methods of reassessment interval determination must be technically justified and validated.

6.4.4 Reassessment intervals cannot exceed the intervals prescribed in Company procedure PS-03-01-260: "Continual Process for Evaluation and Assessment."

6.5 Threat Stabilization

6.5.1 The results of the DG-ICDA process shall be evaluated to determine if the threat of internal corrosion can be considered stabilized or to consider additional actions required to stabilize the threat of internal corrosion. This effort shall be coordinated with ongoing risk assessment activities and the Internal Corrosion Control Program. Reassessment is not required in cases where the internal corrosion threat is stabilized and suitable monitoring equipment is in place to validate continuing status of stabilization.

6.6 Feedback (Continuous Improvement)

6.6.1 Throughout the ICDA process, as well as during scheduled activities and reassessments, efforts shall be made to improve the ICDA applications by incorporating feedback at all appropriate opportunities.

6.6.2 Activities for which feedback shall be considered include:

- Identification of low points and critical inclination angles (CIA)
- Data collection from direct examinations
- Remaining strength analyses
- Root cause analyses
- Remediation activities
- In-process evaluations (tracking feasibility through the first 3 steps)
- Direct examinations used for process validation
- Criteria for monitoring DG-ICDA effectiveness
- Scheduled monitoring and periodic reassessments

Improvements as a result of the DG-ICDA assessment shall be incorporated into future assessments.

6.6.3 Confirm that the subject Data Element Table has been updated with new information obtained during implementation of the DG-ICDA process.

6.6.4 Confirm that the appropriate alignment sheets have been updated with any changes that occurred on the pipeline.

6.6.5 Feedback activities should include a review of data collected during all phases of DG-ICDA.

6.6.6 Evaluating the effectiveness of DG-ICDA as an assessment method of addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified must be carried out within a year of conducting a DG-ICDA assessment.

7.0 OTHER DATA:

7.1 During the Indirect Inspection and Direct Examination activities, other data may be discovered that could be used when performing risk assessments for other threats. For example, when conducting a detailed examination, visual inspection of the pipe may show dents on the top two thirds of the pipe. This may have been caused by third parties. It is appropriate then to use data from the DG-ICDA Detailed Examination visual inspection when conducting integrity assessments for the third party damage threat. This information shall be fed back into the risk assessment process.

8.0 DG-ICDA RECORDS:

8.1 This section describes DG-ICDA records that document data that are pertinent to pre-assessment, indirect inspection, detailed examination, and post assessment.

8.2 All Pre-assessment Step actions shall be recorded. The following checklist may be used to ensure all appropriate records are compiled and maintained:

	System Analysis data collected and Corrosion Manager notified if evidence of historical or active internal corrosion.
	Feasibility assessment performed in accordance with Figure 2 and Table 2.
	Data elements collected for the pipeline segment to be evaluated, in accordance with Procedure PS-03-01-239: Dry Gas - ICDA Data Element Form.
	Basis of assumptions used when actual data is not available.
	Methods and procedures used to integrate the data collected to determine when indirect inspection tools can and cannot be used.
	Technical justification for use of DG-ICDA on any pipeline segment in which a cleaning pig has been used.
	Characteristics and boundaries of DG-ICDA Regions.

8.3 All Indirect Inspection actions shall be recorded. The following checklist may be used to ensure all appropriate records are compiled and maintained:

	Geographically referenced locations of the beginning and ending point of each DG-ICDA Region and each fixed point used for determining the location of each measurement.
	Procedures for determining accuracy of elevation profiles.
	Flow Modeling data and calculations.
	DG-ICDA Water Holdup/Dig Site Selection Plot.

8.4 All Detailed Examination actions shall be recorded. The following checklist may be used to ensure all appropriate records are compiled and maintained:

	Data collected before and after excavation.
	Measured metal-loss corrosion geometries obtained.
	Data used to identify other areas that may be susceptible to corrosion.
	Data used to estimate corrosion growth rates.
	Planned mitigation activities.
	Descriptions of and reasons for any selections of additional dig sites or reprioritizations.

8.5 All Post Assessment actions shall be recorded. The following checklist may be used to ensure all appropriate records are compiled and maintained:

	Remaining life calculation results.
	Maximum remaining flaw size determinations.
	Corrosion growth rate determinations.
	Method of estimating remaining life.
	Results of remaining strength calculations.
	Reassessment intervals, including technical justification and validation of selected method of reassessment, and scheduled activities, if any.
	Criteria used to assess DG-ICDA effectiveness and results from assessments.
	Criteria and metrics.
	Data from periodic assessments.
	Evaluation of threat stabilization for internal corrosion.
	Feedback.
	Monitoring records and recommendations for internal corrosion monitoring

9.0 PERFORMANCE MEASURES:

9.1 The following performance measures shall be documented for the internal corrosion threat in order to establish the effectiveness of the program and for confirmation of the inspection intervals:

- Number of repair actions taken due to direct assessment results, immediate and scheduled.
- Completed DG-ICDA assessment mileage (should be reported in combination with ECDA assessment mileage).

10.0 REFERENCES:

10.1 Regulatory:

- Department of Transportation 49 CFR 192 Subpart O

10.2 Industry Practices:

- ASME B31G
- ASME B31.8
- ASME B31.8S-2001
- RSTRENG
- NACE International Proposed Recommended Practice: “Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)” (Draft #2 – February 2005)
- Gas Research Institute publication GRI 02-0057: “Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology”

10.3 Related Policies and Supporting Documents:

- PS-03-01-239, Dry Gas - ICDA Data Element Form Procedure
- PS-03-01-242, Dig Data Sheet Procedure
- PS-03-01-250, Pipeline Evaluation and Remediation Procedure
- PS-03-01-252, Schedule of Repair Requirements Procedure
- PS-03-01-254, Threat Prevention and Repair Chart Procedure

- PS-03-01-260, Continual Process for Evaluation and Assessment Procedure
- PS-03-02-001, Corrosion Control Program
- PS-03-02-200, Evaluation of Remaining Strength of Corroded Pipe Procedure
- PS-03-02-262, Guided Wave Ultrasonic Inspection Procedure
- Book 1, Manual of Operating & Maintenance Procedures, Specification 226, "Pipeline Repairs - Existing In Service Pipelines"
- Book 2, Manual of Construction Specifications, Specification 96, "Radiographer and Radiographic Procedure Qualification

10.4 **Forms and Attachments:**

- Pre-Assessment Form
- Summary of Indirect Inspection Survey Results – Direct Examination Sites

11.0 DEFINITIONS:

- **Compressibility Factor (Z):** The compressibility factor is the ratio of the actual volume of a given mass of gas at a specified temperature and pressure to its volume calculated from the ideal gas law under the same conditions.
- **Critical Inclination Angle:** The lowest angle of pipeline inclination at which liquid carryover is not expected to occur under stratified flow conditions.
- **Direct Assessment:** A structured process for assessing the integrity of buried pipelines.
- **Detailed Examination:** Examination of the pipe wall at a specific location to determine whether metal loss from internal corrosion has occurred. This may be performed using visual, ultrasonic, radiographic, or other means.
- **Dry Gas:** A gas above its dew point and without condensed liquids.

- **Electrolyte:** A fluid substance through which electrical charge is carried by the movement of ions.

- **Inclination Angle:** An angle resulting from a change in elevation between two points on a pipeline, in degrees.

- **DG-ICDA Region:** A continuous length of pipe (including weld joints) uninterrupted by any significant changes in electrolyte or flow characteristics that includes similar physical characteristics and operating history. A DG-ICDA Region may contain one or more covered pipe segments (High Consequence Areas)

- **Liquid Holdup:** Accumulation of liquid (that is, input liquid volume is greater than output liquid volume).

- **Low Point:** A location having higher elevations immediately adjacent upstream and downstream; any liquid is expected to preferentially collect at such locations during stagnant flow conditions.

- **Maximum Allowable Operating Pressure (MAOP):** The maximum internal pressure permitted during the operation of a pipeline.

- **Microbiologically Influenced Corrosion (MIC):** Localized corrosion resulting from the presence and activities of organisms, including bacteria and fungi.

- **Multiphase Flow:** Flow involving more than one phase (for example, gas and liquid).

- **Segment:** A portion of a pipeline that is assessed using DG-ICDA. A segment may consist of one or more DG-ICDA Regions.

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

- **Specified Minimum Yield Strength (SMYS):** The specified minimum yield strength is the minimum yield strength of the steel in pipe as required by the pipe product specifications.

- **Superficial Gas Velocity:** The volumetric flow rate of gas (at system temperature and pressure) divided by the cross-sectional area of the pipe.

APPENDIX A

Methodology for Producing Pipeline Elevation Profile

A1.0 INTRODUCTION:

A1.1 This methodology shall be used by the Company's Direct Assessment Crew to determine the pipeline depth of cover, in coordination with a land survey team using Global Positioning System/Real Time Kinetics (GPS/RTK), to produce a pipeline elevation profile.

A1.2 GPS/RTK equipment has the capability to produce sub-centimeter survey accuracy.

A1.3 The objective of the survey is to combine the depth of cover data with the GPS/RTK pipeline centerline data to produce a highly accurate pipeline elevation profile that is fundamental for the successful application of Dry Gas Internal Corrosion Direct Assessment (DG-ICDA).

A1.4 The pipeline elevation profile is required in order to determine low points and critical inclination angles that may exist within DG-ICDA Regions, with a focus on collecting pipeline elevation profile data within covered segments (high consequence areas within the DG-ICDA Region). These low points and angles of inclination may be potential sites where water could accumulate and lead to internal corrosion. Depending on further engineering evaluation, these locations may be potential sites for Direct Examination activities.

A2.0 IDENTIFICATION OF DG-ICDA CANDIDATE PIPELINE AND DG-ICDA REGION DELINEATION

A2.1 Based on previously completed Pre-assessment activities, the DG-ICDA candidate pipeline with delineation of covered segments (that is, high consequence areas, or HCAs) and DG-ICDA Regions (in both gas flow directions, if applicable) shall be clearly identified to the Direct Assessment (DA) Field Crew and the Land Survey Team in advance of proceeding to the field to collect the pipeline elevation profile information.

A2.2 If the gas within the DG-ICDA candidate pipeline has been determined (by pre-assessment) to flow in opposite directions within one DG-ICDA Region, then this defines two DG-ICDA Regions (one for each direction). Each of the respective DG-ICDA Regions must be distinctly and separately labeled (for example, "DG-ICDA Region 1 - North to South" and "DG-ICDA Region 1 - South to North"). The DA Support Team will provide this data to the DA Field Crew and the Land Survey Team by indicating the delineation of each DG-ICDA Region on the Pipeline Alignment Sheets. Copies of the Pipeline Alignment Sheets shall be provided to both the DA Field Crew and the Land Survey Team. A Land Survey Team company representative shall sign for any proprietary data and information that is the property of the Company.

A3.0 IDENTIFICATION OF COVERED SEGMENTS AND CRITICAL INCLINATION ANGLES WITHIN DG-ICDA REGIONS

A3.1 The location of HCAs and the value for the Critical Inclination Angle for each DG-ICDA Region shall be calculated and clearly identified to the DA Field Crew and the Land Survey Team in advance of proceeding to the field to collect the pipeline elevation profile information. The DA Support Team shall provide this data to the DA Field Crew and the Land Survey Team by indicating the DG-ICDA Critical Inclination Angle on the Pipeline Alignment Sheets. The DA Support Team shall notify the DA Field Crew and Land Survey Team when there is more than one critical inclination angle within each DG-ICDA Region.

A4.0 SURVEY APPROACH BASED ON THE EXPECTED LOCATION OF THE CRITICAL INCLINATION ANGLE

A4.1 Based on the lay of the land shown on the Pipeline Alignment Sheets and the calculated critical inclination angle(s), the DA Support Team shall review the Pipeline Alignment Sheets and identify where critical inclination angles may potentially be located. The DA Support Team should focus on the location of HCAs within the DG-ICDA Region. The intent of the survey is to record very highly accurate pipeline elevation profile data, particularly preceding, following, and at the location where a critical inclination angle may occur. Typically, a critical inclination angle may occur where there is a rise in the pipeline profile, which may be evident by a visual rise in the terrain (that is, assuming a constant depth of cover over the pipeline). Identifying the location where a critical inclination angle might be expected, in advance of the field survey, assists the survey teams in determining when closer attention to detail might be needed and when more survey data points (that is, shorter intervals) might be required. Both the DA Field Crew and Land Survey Team should keep in mind that some critical inclination angles may be very small (only a few degrees) which, therefore, may require highly accurate pipeline elevation profile data.

A4.2 Based on the combined DG-ICDA Region delineation and the calculated critical inclination angle, the DA Support Team shall determine the approximate location of critical inclination angles and delineate where there should be focus on collecting the pipeline elevation profile data. Note that in some cases, the survey for data collection may focus only in (and possibly adjacent to) High Consequence Areas (HCAs) which may mean performing intermittent surveys within the identified DG-ICDA Region. This data will be used by the Land Survey Team, as a guideline, only to determine how long of a survey may be necessary. Once the end of the DG-ICDA Region is reached, the survey is considered complete. The survey crews must rely on actual data collected and coordinated by the Land Survey Team rather than the preliminary data that is provided by the DA Support Team.

A4.3 Based on the combined DG-ICDA Region delineation and the calculated critical inclination angle, the DA Support Team shall determine the approximate location where critical inclination angles (in both directions of each DG-ICDA Region) might be expected. This observation will help to determine if surveys within two overlapping DG-ICDA Regions (that is, approaching from opposite directions) may require the collection of highly accurate elevation data in both uphill and downhill directions. The DA Support Team will provide this data to the DA Field Crew and the Land Survey Team by indicating the expected locations of DG-ICDA critical inclination angles on Pipeline Alignment Sheets. If some of the critical inclination angles overlap from opposite directions within two overlapping DG-ICDA Regions, then the DA Support Team shall recognize that highly accurate elevation data will be required for both uphill and downhill slopes along the entire length where DG-ICDA Regions are mutually inclusive and the overlap occurs.

A4.4 The DA Field Crew and the Land Survey Team must observe if there are DG-ICDA Regions starting from opposite ends of the pipeline segment (based on the fact that gas has been flowing in opposite directions within the pipeline at some time within the relatively recent past). If gas flow has been determined to be bi-directional (that is, gas flowing in both directions), then close attention to collecting highly accurate pipeline elevation data is required when encountering both uphill and downhill slopes (as the pipe will be evaluated in both directions). However, if the pipe has only been exposed to unidirectional gas flow (that is, not been exposed to bi-directional flow), then close attention to collecting highly accurate pipeline elevation data along uphill slopes only is required (and not downhill slopes). Refer to the following Table A1.

Table A1: Depth of Cover and GPS/RTK Tool Distance Interval for Data Recording

	Distance Interval for Data Recording	
Type of Grade Visually Detected Above Pipeline	**Type of Gas Flow History within Pipeline DG-ICDA Region**	
	Unidirectional	**Bi-directional**
Uphill slope including hill crest	Depending on extent of grade, as short as 5 feet	Depending on extent of grade, as short as 5 feet
Downhill slope after hill crest following an uphill slope	Continue with 5-foot interval to distance of 30 feet beyond crest of hill, afterwards increase interval gradually to 50 feet	Depending on extent of grade, as short as 5 feet
Downhill slope following after a relatively flat terrain	Every 50 feet	Depending on extent of grade, as short as 5 feet
Relatively flat	Every 50 feet	Every 50 feet

A5.0 COLLECTION OF DATA REQUIRED TO PRODUCE PIPELINE ELEVATION PROFILE

A5.1 The DA Field Crew shall be responsible for collecting depth of cover data for the DG-ICDA candidate pipeline by using an appropriate pipeline depth locating tool (for example, Pipeline Current Mapper (PCM) or radio detection pipe locator). The Land Survey Team shall be responsible for collecting the data to accurately produce the pipeline centerline using GPS/RTK (or other suitable means if terrain/interference or other reason prevents the use of GPS/RTK). Once the two data sets have been collected, the two data sets will be combined to produce a highly accurate Pipeline Elevation Profile.

A5.2 As a minimum, the DA Field Crew will require the following equipment and supplies:

- Radio detection pipe locator
  - Radio detection transmitter
  - Radio detection receiver
  - Spare batteries

- Pipeline Current Mapper (PCM), consisting of:
  - PCM Transmitter

  - PCM Receiver
  - Suitable ground for current return
  - Spare batteries

- Power source for PCM Transmitter

- Large supply of pipeline identification flags (approximately 1,000 flags)

- Utility marking paint

- Three permanent black ink markers (two for back-up supply)

- Cell phone and radio communication equipment

A5.3 As a minimum, the Land Survey Team will require the following equipment:

- GPS/RTK equipment

- Cell phone and radio communication equipment

A5.4 Based on a previously determined schedule, the DA Field Crew and the Land Survey Team shall meet at the survey starting point for a pre-job tailgate meeting. Items that shall be covered include, but are not limited to the following:

- Identifying the survey beginning or anchor point (the anchor point is the beginning point for both the depth of cover and the GPS/RTK surveys and ensures proper alignment for integration purposes), the expected length and/or range of the survey, and whether the survey may be intermittent within the identified DG-ICDA Region. In some cases, the survey may only be conducted in (and possibly adjacent to) High Consequence Areas (HCAs) which may mean performing intermittent surveys within the identified DG-ICDA Region.

- The best method of communication between survey crews. This shall take into account the following variables: the surrounding environment, communication interference, ranges of equipment, the length of the survey, and the potential distance in separation between the two teams.

- A preview of the Pipeline Alignment Sheets.

- A review of the Critical Inclination Angles and where they might occur. (Knowing where these locations exist will assist the teams in knowing where more highly accurate detail to data collection may be required. Refer to Table B1).

- Review of the proper tool distance intervals and where it may deviate.

- Calibration of equipment.

- A review of appropriate Pre-Job Safety measures

A5.5 The starting point for the survey shall be the very beginning of the DG-ICDA Region or before the start of the first covered segment downstream of the beginning of the DG-ICDA Region. (Note that in some cases, depending on the grade and the expected location of pipeline low points or critical inclination angles, it may be necessary to begin the collection of survey data a slight distance upstream the beginning of the DG-ICDA Region or the first covered segment.)The DA Field Crew and the Land Survey Team shall determine the best method of communication given the surrounding environment, communication interferences, ranges of equipment, the length of the survey, the potential distance in separation between the two teams, the suitability for communication options, etc.

A5.6 The two crews shall review the Pipeline Alignment Sheets to determine where the Critical Inclination Angles have been pre-identified as possibly existing. The DA Field Crew shall start by locating the pipe and recording the depth of cover at the beginning or anchor point for collection of the data (that is, data point 1). The depth of cover shall be determined and recorded, along with the data point number, using the appropriate pipe location tool. The data point number and the depth of cover shall also be recorded on a pipeline location flag using a permanent black ink marker (the use of location flags is not necessary if the two teams can work side by side; see step A5.10 of this Appendix). Information on the pipeline location flag shall be clear and legible so that there is no misinterpretation of the data point number and the depth of cover at that location. Place the flag securely in the ground immediately above the pipe centerline (approximately).

A5.7 In the event the pipeline is located under pavement, the data point and depth of cover shall be recorded on a flag placed in the ground perpendicular to the actual pipeline location and the actual pipeline location shall be marked on the pavement surface using utility marking paint. The data on the flag shall include distance to the actual pipeline location and compass heading to the centerline location. If a suitable spot for flag placement is not available, then marking the data point number and depth of cover on the pavement with utility marking paint will suffice.

A5.8 Based on the terrain/grade (that is, the presence of an uphill slope, downhill slope, or relatively flat terrain), whether the pipeline has been exposed to bi-directional flow, and whether there is an overlap of DG-ICDA Regions will dictate the distance along the pipeline that the crew should travel before the next data point number where they will record the next depth of cover measurement.

A5.9 Based on the interval spacing indicated in Table B1, the DA Field Crew shall record the next sequential data point number (that is, data point 2) and the depth of cover measurement via use of the pipe location tool. The data point number and the depth of cover shall be recorded on a pipeline location flag using a permanent black ink marker. Again, clear and legible markings are required so that there is no misinterpretation of the data point number or the depth of cover at that location. Place the flag securely in the ground immediately above the pipe centerline (approximately). This procedure shall be repeated until such time as the Land Survey Team indicates that it is unnecessary to proceed further with the survey as information on the location of critical inclination angles has been adequately collected.

A5.10 As the DA Field Crew proceeds to take depth of cover measurements; the Land Survey Team shall follow immediately behind and collect GPS/RTK readings at each pipeline location flag marker. The Land Survey Team shall also record each data point number and depth of cover measurement that has been marked on each pipeline location flag. If there is ever any confusion as to the depth of cover at a particular data point, the Land Survey Team shall verbally contact the DA Field Crew and cross reference the data point number to get the correct depth of cover. Ideally, it is best if the DA Field Crew and Land Survey Team can work side by side while collecting the pipeline elevation data. If this is possible, then the use of pipeline location flags is not necessary as the two teams can verbally exchange data as they proceed along the pipeline.

A5.11 The Land Survey Team shall continue along the pipeline taking and recording GPS/RTK readings at every pipeline location flag/data collection point where the depth of cover measurements were taken. The GPS/RTK measurements shall be combined with the depth of cover measurements to produce a real-time representation of the pipeline elevation profile. The Land Survey Team shall use this information to determine when the pipeline experiences an inclination angle. With this information, and combined with knowledge of the calculated Critical Inclination Angle for the DG-ICDA Region being surveyed, the Land Survey Team shall determine where Critical Inclination Angles exist.

A5.12 Based on the pipeline elevation profile that the Land Survey Team produces, the Land Survey Team shall notify the DA Field Crew when the DG-ICDA Region has been surveyed. At this point, the survey, for this direction of the DG-ICDA Region (i.e., “DG-ICDA Region 1 – North to South”), is considered to be adequate and complete. If there is an overlap of DG-ICDA Regions, some of the survey data for the other DG-ICDA Region (i.e., “DG-ICDA Region 1 – South to North”) may be considered adequate and compete as well.

A5.13 The Land Survey Team shall take this information into account and determine what length of survey shall be required from the opposite direction (i.e., “DG-ICDA Region 1 – South to North”) so that all necessary data is collected but not collected twice unnecessarily.

A6.0 COMPILATION OF PIPELINE ELEVATION DATA

A6.1 The Land Survey Team shall combine the depth of cover and the GPS/RTK data to produce an accurate Pipeline Elevation Profile. The Land Survey Team shall provide this data to the DA Field Crew as soon as possible (within a two week period) after completion of the data collection.

A6.2 Immediately upon completion of the survey, the Land Survey Team shall surrender all survey data, Pipeline Alignment Sheets, information on Critical Inclination Angles, and any other data that is considered proprietary in nature and the property of the Company to the designated Company representative.

A6.3 The DA Field Crew shall provide the pipeline elevation profile to the Data Management Specialist of the DA Support Team, as soon as possible after survey completion. It is expected that the Pipeline Elevation Profile data will be combined with calculated values for the Critical Inclination Angle to produce a DG-ICDA Water Holdup / Dig Site Selection Plot. This activity completes a significant component of the Indirect Inspection (Step 2) of the DG-ICDA Program.

1.0 PURPOSE:

1.1 This procedure establishes the process necessary for properly conducting a direct assessment of the stress corrosion cracking threat in natural gas pipelines. Stress corrosion cracking (SCC) is the brittle cracking of a normally ductile material caused by the combination of a corrosive environment with tensile stress. This program addresses both high pH SCC and near-neutral pH SCC.

1.2 Stress corrosion cracking direct assessment is a structured process for identifying potential SCC in pipeline segments, selecting excavation sites, inspecting the pipe and collecting and analyzing data collected during the excavation, establishing a mitigation program, defining reevaluation intervals and evaluating the effectiveness of the program.

2.0 PROCEDURE:

2.1 The Stress Corrosion Cracking Direct Assessment (SCCDA) process consists of four steps: Pre-assessment, Indirect Inspection, Direct Examination, and Post Assessment.

2.2 In the pre-assessment step, historic and currently available data are collected and analyzed to prioritize the pipeline segments within a pipeline system with respect to potential susceptibility to SCC and to select specific sites within those segments for direct examinations. The types of data collected are typically available from construction records, operating and maintenance records, government sources, and inspection reports from prior integrity evaluations or maintenance actions.

2.3 In the indirect inspection step, additional data are collected as necessary to aid prioritization of pipeline segments and in site selection. The necessity to conduct indirect inspections and the nature of these inspections depends on the nature and extent of the data obtained in the Pre-assessment step and the data needs for site selection. Typical data collected in this step might include close interval survey (CIS) data, direct current voltage gradient survey (DCVG) data, and information on terrain conditions, such as soil type, topography, and drainage, along the right of way.

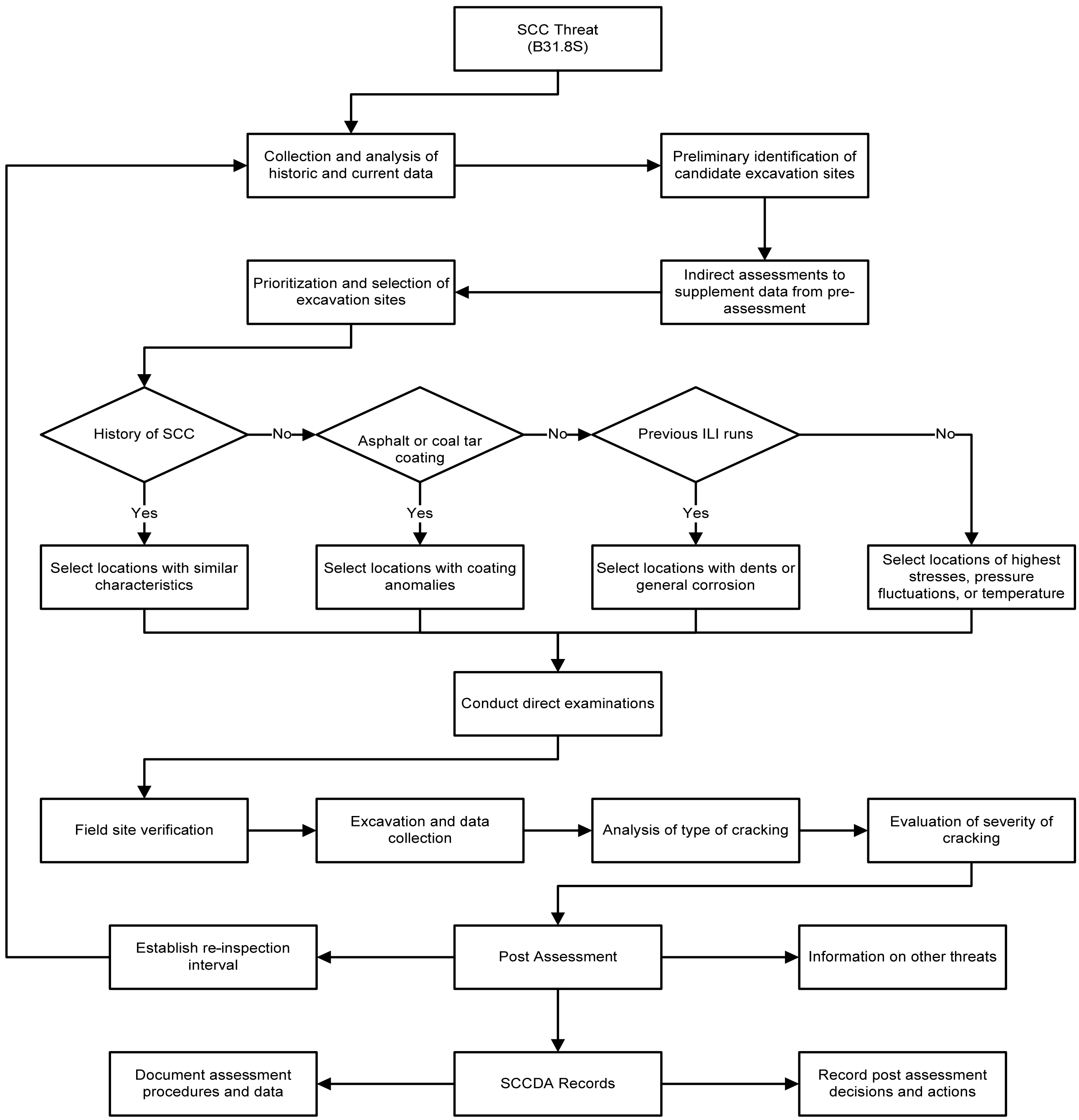
2.4 The direct examination step includes procedures to field-verify the sites selected in the first two steps, and to conduct the field excavations.

Aboveground measurements and inspections are performed to field verify the factors used to select the excavation sites. The excavations are then performed; the severity, extent, and type of SCC (if any is detected) at the individual excavation sites are assessed, and data are collected that can be used in post assessment.

2.5 In the post assessment step, data collected from the previous three steps are analyzed to determine whether SCC mitigation is required, to prioritize mitigation actions, to define reassessment intervals, and to evaluate the effectiveness of the SCCDA process.

2.6 Figure 1 provides a flowchart for the SCCDA process.

FIGURE 1
PROCESS FLOWCHART
STRESS CORROSION CRACKING DIRECT ASSESSMENT



3.0 PRE-ASSESSMENT:

3.1 The objective of the pre-assessment step is to collect and analyze historic and current data, to prioritize potentially susceptible segments of pipelines and help select specific sites within those segments.

3.2 Susceptibility to SCC

3.2.1 A pipeline segment is considered to be susceptible to high pH SCC if all of the following factors are met. It is recognized that these screening factors will identify a substantial percentage of the susceptible locations, but not necessarily all of them.

- Operating stress exceeds 60% of the specified minimum yield strength (SMYS)
- Operating temperature has historically exceeded 100°F
- Distance from a compressor station is equal to or less than 20 miles downstream
- Age of pipe is equal to or greater than 10 years
- All corrosion coating systems other than fusion bonded epoxy (FBE)

3.2.2 A pipeline segment is considered to be susceptible to near-neutral pH SCC if all the same factors above, except for the temperature component, are met.

3.3 Criteria and Risk Assessment

3.3.1 Each pipeline segment in which one or more service incidents, or one or more hydrostatic test breaks or leaks has been caused by one of the two types of SCC shall be evaluated unless the conditions that led to the SCC have been corrected.

3.3.2 For the stress corrosion cracking threat, the risk assessment consists of comparing the data elements collected in Section 3.4, “Data Collection and Segment Prioritization”, below to the criteria identified in factors previously outlined. If the conditions of the criteria are met, or if the pipeline segment has a previous SCC history (for example, bell hole inspection indicating SCC, hydrostatic test failures caused by SCC, in-service failures caused by SCC, or leaks caused by SCC) the pipe is considered to be at risk for the occurrence of SCC.

3.3.3 If any one of the conditions of the criteria is not met and if the segment does not have a history of SCC, action is not required.

3.4 Data Collection

3.4.1 Historical and current data shall be collected along with physical information for the segment to be evaluated.

A. Minimum data requirements shall be defined based on the history and condition of the pipeline segment. Data elements in Table 1: "SCCDA Data Elements" have been prioritized as Required or Optional. Required and optional data elements are defined as follows:

- Required – Data elements required to execute SCCDA. Any exceptions and conservation assumptions shall be documented in the event the Company elects to execute SCCDA where some required data elements are unavailable at the time of pre-assessment preparation. Documentation will be stored in the feasibility section of the pre-assessment document (Section 10.4 of this procedure).
- Optional – Data elements not required for execution of SCCDA. The Company shall make diligent effort to complete all optional data elements.

3.4.2 All parameters that impact indirect inspection tool selection and SCCDA region definition shall be considered for initial SCCDA process applications on a pipeline segment.

3.4.3 At a minimum, the data elements shown in Table 1: "SCCDA Data Elements" shall be addressed. The data elements provide guidance on the types of data to be collected. Not all items in Table 1 are necessary for the entire pipeline. When approved by the Company, conservative defaults may be substituted as applicable. Also, it may be determined that items not in Table 1 are necessary. The elements are divided into five categories:

- Pipe-Related
- Construction-Related
- Soils/Environmental
- Corrosion Control
- Operational Data

TABLE 1
Factors to Consider in Prioritization of Susceptible Segments and in Site Selection

The relative importance of each data element (see last column) is:

R = Required – Data elements required to execute SCCDA.
O = Optional – Data elements not required for execution of SCCDA.

Factor	Relevance	Use and Interpretation of Results	Ranking (R) = Required (O) = Optional
PIPE-RELATED			
Grade	No known correlation with SCC susceptibility	Background data needed to calculate stress as percent of SMYS	R
Diameter	No known correlation with SCC susceptibility	Background data needed to calculate stress from internal pressure	R
Wall thickness	No known correlation with SCC susceptibility	Impacts critical defect size and remaining life predictions. Needed to calculate stress from internal pressure	R
Year manufactured	No known correlation with SCC susceptibility	Older pipe materials typically have lower toughness levels, reducing critical defect size and remaining life predictions.	O
Pipe manufacturer	Near-neutral pH SCC has been found preferentially in the heat-affected zone of ERW pipe that was manufactured by Youngstown Sheet and Tube in the 1950s. Reported to be statistically significant predictor for near-neutral pH SCC in system model for one pipeline system.	Important factor to consider for near-neutral pH SCC	O

Factor	Relevance	Use and Interpretation of Results	Ranking (R) = Required (O) = Optional
Seam type	Near-neutral pH SCC has been found preferentially under tented tape coatings along DSA welds and in heat-affected zones along some electric-resistance welds. No known correlation with high pH SCC.	May be important factor to consider for near-neutral pH SCC	O
Surface preparation	Shot peening or grit blasting can be beneficial by introducing compressive residual stresses at the surface, inhibiting crack initiation, and by removing mill scale, making it difficult to hold the potential in the critical range for high pH SCC.	Important factor to consider for both high pH and near-neutral pH SCC	O
oating type	To date, SCC has not been reported for pipe with undamaged fusion-bonded epoxy (FBE) coating or with extruded polyethylene coating.	Important factor to consider for both high pH and near-neutral pH SCC	R
Bare pipe	SCC has been observed on bare pipe in high-resistivity soils	May be important factor	O
Hard spots	There have been instances in which near-neutral pH SCC has occurred preferentially in hard spots, which can be located by ILI that measures residual magnetism.	May be important factor	O
CONSTRUCTION-RELATED			
Year installed	Impacts time over which coating degradation may occur and cracks may have been growing	Age of pipeline used in criteria for selection of susceptible segments	O
Route changes and modifications		May be important for accurately locating each site	R
Route maps, aerial photos		May be important for accurately locating each site	O
Construction practices	Backfill practices influence probability of coating damage during construction. Also, time between burying of pipe and installation of CP might be important.	Early levels of CP might be important	O
Surface preparation for field coating	Mill scale promotes potential in critical range for high pH SCC	May be discriminating factor	O
Field coating type	High pH SCC found under coal tar, asphalt, and tape. Near-neutral pH SCC most prevalent under tape but also found under asphalt. Weather conditions during construction also may be important in affecting coating condition.	Important factor to consider for near-neutral pH SCC	R
Location of weights and anchors	Near-neutral pH SCC has been found under buoyancy-control weights.		R

Factor	Relevance	Use and Interpretation of Results	Ranking (R) = Required (O) = Optional
Locations of valves, clamps, supports, taps, mechanical couplings, expansion joints, cast iron components, tie-ins, and insulating joints		May be important for accurately locating and characterizing each site	R
Locations of casings	CP shielding and coating damage more likely within casings	May be important for accurately locating and characterizing each site	R
Locations of bends, including miter bends and wrinkle bends	Might indicate unusual residual stresses	Residual stress may be an important factor	O
Location of dents	Might indicate unusual residual stresses	Residual stress may be an important factor	R
SOILS/ENVIRONMENTAL			
Soil characteristics and types	No known correlation between soil type and high pH SCC, except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. Some success has been experienced in correlating near-neutral pH SCC with specific soil types.	Might be important, especially for near-neutral pH SCC	R
Drainage	Has been correlated with both high pH and near-neutral pH SCC	Might be important parameter	R
Topography	Has been correlated with both high pH and near-neutral pH SCC, possibly related to effect on drainage. Also, circumferential near-neutral pH SCC has been observed on slopes where soil movement has occurred.	Might be important parameter	R
Land use (current/past)	No obvious correlations have been found, but use of fertilizer might affect soil chemistry as related to trapped water under disbonded coatings.	Might be important parameter	R
Groundwater	Groundwater conductivity affects the throwing power of CP systems	Might be important parameter	O
Location of river crossings	Affects soil moisture/drainage	Might be important parameter	R

Factor	Relevance	Use and Interpretation of Results	Ranking (R) = Required (O) = Optional
CORROSION CONTROL			
CP system type (anodes, rectifiers, and locations)	Adequate CP can prevent SCC if it reaches under disbonded coatings	Important parameter	R
CP evaluation criteria	Adequate CP can prevent SCC if it reaches under disbonded coatings	Background information	R
CP maintenance history	Adequate CP can prevent SCC if it reaches under disbonded coatings	Background information	R
Years without CP applied	For high pH SCC, absence of CP might allow harmful oxides to form on pipe surface. For near-neutral pH SCC occurring at or near the open-circuit potential, absence of CP could allow SCC to proceed.	Important parameter	O
CIS and test station information	Although high pH SCC occurs in a narrow range of potentials (typically between 575 and 825 mV vs. copper/copper sulfate depending on temperature and solution composition), it has been observed on pipe that appeared to be adequately cathodically protected, because the actual potential as the pipe surface can be less negative than the aboveground measurements because of shielding by disbonded coatings. Nevertheless, locations of cracks might correlate with CP history, especially if problems had been encountered in the past.	Important factor to consider for both high pH and near-neutral pH SCC	R
Coating-fault survey information	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information	R
Coating system and condition	Because SCC requires coating faults, indications of coating condition might help locate probable areas.	Important background information	O
OPERATIONAL DATA			
Pipe operating temperature	Elevated Temperatures have strong accelerating effect on high pH SCC. For near-neutral pH SCC, temperature probably has little effect on crack growth rate, but elevated temperatures can contribute to coating deterioration.	Important, especially for high pH SCC	O
Operating stress levels and fluctuations	Stress must be above a certain threshold for SCC to occur. Fluctuating stresses can significantly reduce the threshold stress.	Impacts SCC initiation, critical flaw size, and remaining life predictions	R
Leak/rupture history (SCC)	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important	R
Direct inspection and repair history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important	R

Factor	Relevance	Use and Interpretation of Results	Ranking (R) = Required (O) = Optiona
Hydrostatic retest history	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important	R
ILI data from crack-detecting pig	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	Important	R
ILI data from metal-loss pig	If a metal-loss pig indicates corrosion on a tape-coated pipe where there is no apparent indication of a holiday, the coating is probably disbonded and shielding the pipe from CP, a condition in which SCC – especially near-neutral pH SCC – has been observed.	May be important	R

3.4.3 The data collected in the pre-assessment step often includes the same data typically considered in an overall pipeline risk (threat) assessment. Depending on the integrity management plan and its implementation, the SCCDA pre-assessment step may be conducted in conjunction with a general risk assessment effort.

3.4.4 In the event that it is determined that sufficient data for a SCCDA pipeline segment is not available or cannot be collected to support the pre-assessment step, SCCDA shall not be used for those SCCDA segments.

3.4.5 The Pre-Assessment form provided in this procedure is an Excel spreadsheet with specific tabs addressing the five data element tables, segment definition, tool selection, and change log.

3.4.6 The spreadsheet is available in Section 10.4 of this procedure. This pre-assessment form shall be utilized for all SCCDA assessments.

3.4.7 The change log (referenced above) shall be utilized to document any required changes that present in any of the four steps of SCCDA.

3.4.8 Throughout the SCCDA process, as well as during scheduled activities efforts shall be made to improve the SCCDA process by incorporating feedback at all appropriate opportunities. Improvements of the SCCDA process shall be incorporated into future pre-assessments.

3.4.9 There are no published correlations between soil composition and high pH SCC except for some evidence that high sodium or potassium levels might promote development of concentrated carbonate/bicarbonate solutions under disbonded coatings. There is some evidence that pipelines in soils that experience alternate periods of high and low moisture might be more prone to SCC, and there is one report of a pipeline that traversed alternate areas of wet, low-resistivity clay, and dry high-resistivity sand and experienced SCC only in the low-resistivity areas.

3.4.10 Some success has been experienced in correlating near-neutral pH SCC with specific soil types, drainage, and topography. Tables 2 and 3 are descriptions of the SCC-susceptible terrain conditions identified for polyethylene-tape-coated and asphalt/coal-tar-coated pipelines, respectively.

TABLE 2

Terrain Conditions for Polyethylene Tape-Coated Pipe

Soil Environmental Description	Topography	Drainage
Clay bottom creeks and streams (generally less than 16 feet in width)	------------------------------	------------------------------
Lacustrine (clayey to silty, fine textured soils)	Inclined, level, undulating	Very poor
Lacustrine (clayey to silty, fine textured soils)	Inclined, level, undulating, depressional	Poor
Organic soils (>3 feet in depth) overlaying glaciofluvial (sandy and/or gravel textured soils)	Level, depressional	Very poor
Organic soils (>3 feet in depth) overlaying lacustrine (clayey to silty, fine-textured soils)	Level, depressional	Very poor
Moraine tills (variable soil texture - sand, gravel, silt, and clay with a stone content > 1%)	Inclined to level, level undulating, ridged, depressional	Very poor Poor Imperfect to poor
Moraine tills (variable soil texture - sand, gravel, silt, and clay with a stone content > 1%)	Inclined	Poor, Imperfect to poor

TABLE 3
Terrain Conditions for Asphalt/Coal Tar Enamel Coated Pipe

Soil Environmental Condition	Topography	Drainage
Bedrock and shale limestone (< 3 feet of soil cover over bedrock or shale limestone	Inclined level Undulating ridged	Well
Glaciofluvial (Sandy and/or gravel textured soils)	Inclined level Undulating ridged	Well
Moraine till (Sandy/clay soil texture with a stone content > 1%)	Inclined level Undulating ridged	Well
Sites that do not meet the -850mV “off” criteria in a close pipe to soil survey (Exclusive of the three sets of terrain conditions discussed above)	Any	Any

3.5 Selection of Dig Sites in Susceptible Segments

3.5.1 If additional information is desired or needed, this step (3.5) should be delayed until an indirect inspection, as described in Section 4.0, is completed.

3.5.2 Ideally, the dig sites should be selected to maximize the probability of finding SCC if it does exist on the pipe. However, there are no well-established methods for predicting with a high degree of certainty the presence of SCC based upon aboveground measurements. However, industry experience can provide some guidance for selecting more probable sites. The critical factors for high pH SCC and near-neutral pH SCC are similar, but some differences may exist. Also, the most relevant factors may differ from one pipeline to another or even one segment to another, depending upon the history of the pipeline.

3.5.3 Predictive models can be effective at identifying and ranking areas along a pipeline that are susceptible to near-neutral pH. Predictive models are effective only if reliable pipe and terrain conditions are used and the predictive model is verified and enhanced through investigative excavations.

3.5.4 Following are factors that shall be considered in order of their reliability for locating SCC, and they should be used in the order presented unless insight is available to support proceeding otherwise. Aboveground location measurements shall be recorded with sub-meter accuracy global positioning systems (GPS) to provide for accurate data comparison between surveys, to identify significant aboveground reference points in the survey data, and to allow for future relocation to excavation locations. GPS coordinates shall be recorded in Geographic Projection (Latitude/Longitude) Decimal Degrees.

A. If there is a history of SCC in the area of interest (for example, service failures, hydrostatic test failures, in-line inspection indications, or previous excavations) excavation should take place near the previous locations of SCC. Industry experience indicates that there is a high probability of SCC occurring near other places where it has been found.

B. If previous SCC locations have been associated with unique characteristics of the pipe, excavation should take place in other areas with those same characteristics. Industry experience indicates there are some correlations with areas of mechanical damage such as dents; geophysical features such as soil moisture, drainage, or soil type; steep slopes with soil subsidence; or coating anomalies.

C. If there is no history of SCC in the area of interest, locations with coating anomalies should be considered. For coatings such as coal tar or asphalt, these areas might be identified from a close interval survey or a coating-fault survey.

D. If in-line inspection (ILI) tools for features such as geometry or metal loss have been run in pipe with coatings that may shield the pipe and there is no history of SCC in the area, locations of dents or general corrosion should be considered because both features have sometimes been associated with SCC.

E. In the absence of any other suitable indicators, locations where the stresses, pressure fluctuations, and temperatures were highest or where there has been a history of coating deterioration should be selected.

F. For subsequent excavations in the same area, sites should be selected that have the same unique features that were revealed in earlier excavations, if there were any. If not, select other areas where stresses, pressure fluctuations, and/or temperatures were relatively high should be selected.

G. It is critical to ensure that an exposed joint of pipe corresponds to the one that contained an ILI indication. The identity of the joint shall be confirmed by comparing the measured distance between girth welds, the circumferential position of the longitudinal seam weld, and the location of aboveground markers with the indications on the ILI log.

4.0 INDIRECT INSPECTION:

4.1 The objectives of the indirect inspection step are to conduct aboveground or other types of measurements to supplement the data from the pre-assessment step, if additional information is needed, and then to use the data to prioritize susceptible pipeline segments and select the specific sites for direct examination.

4.2 The nature of the data collected in this step supports the quality of the data collected in the pre-assessment step.

4.3 Aboveground measurements may include activities such as close interval surveys (CIS), coating fault surveys such as the direct current voltage gradient (DCVG) survey, alternating current voltage gradient (ACVG) or additional geological surveys and characterizations.

4.4 Other types of data that might be obtained in the indirect inspection step include: locations of dents and bends found with ILI geometry tools on pipelines where SCC has been associated with such features, and areas of coating disbondment and corrosion located by ILI magnetic flux leakage tools on pipelines where SCC has been associated with such features.

4.5 Summary of indications:

- A summary of indications shall be prepared utilizing the form “Summary of Indirect Inspection Survey Results – Direct Examination Sites.” This form is provided in Section 10.4 of this procedure.

5.0 DIRECT EXAMINATION:

5.1 The objectives of the Direct Examination step are to examine the pipe at locations chosen after the pre-assessment step and, if applicable, the indirect inspection step and, if SCC is detected, to assess the presence, extent, type, and severity of SCC at the individual dig sites.

5.2 The types and extent of data collected at the dig sites is discretionary and depends on the planned usages of the data. A listing of the types of data to consider is provided in Table 4.

5.2.1 Limited data, consisting of the assessment of cracking, is appropriate when assessing a pipeline segment for the presence or absence of SCC. More extensive data collection procedures are required if a predictive model for SCC on a pipeline system will be developed.

5.2.2 If cracks are found, the crack dimension data used to establish serviceability of the pipeline shall be recorded.

TABLE 4

Data Collected at a Dig Site and Relative Importance

Data Element	When Collected	Use and Interpretation of Results	Ranking
Pipe-to-soil potential	Prior to coating removal	Useful for comparison with ground surface pipe-to-soil potential measurements	D
Soil resistivity	Prior to coating removal	Related to soil corrosiveness and soluble cation concentration of soil. Useful for comparison with results of soil and groundwater analyses.	C
Soil samples	Prior to coating removal	Useful in confirming terrain conditions. Soil analysis results can be trended in predictive model	B
Groundwater samples	Prior to coating removal	Chemistry results can be trended in predictive model	B
Coating type	Prior to coating removal	Required element. Used for field site verification and in predictive model development	A
Coating condition	Prior to coating removal	Can be related to extent of SCC found	C
Measurement of coating disbondment	Prior to coating removal	Locations of disbondment can be related to presence of cracking and other measured data	C
Electrolyte	Prior to coating removal	Useful in establishing type of cracking. Can be related to groundwater chemistry.	C
Photograph of dig site	Prior to coating removal	Useful in confirming terrain conditions, coating type, and coating condition	D
Data for other integrity analyses	Before and after coating removal	Data for other analyses (e.g., dent measurements) may be related to occurrence of SCC	C, D
Deposit description and photograph	After coating removal	Useful in establishing type of cracking	C
Deposit analysis	After coating removal	Useful in establishing type of cracking	C
Identification and measurement of corrosion defects	After coating removal	Used for integrity assessment of corrosion defects. Also used in establishing type of SCC, if present	A, D
Photograph of corrosion defects	After coating removal	Used in integrity assessments	D
Identify weld seam type	After coating removal	Required element. Used in field site verification	A
MPI and/or dye penetrant inspection	After coating removal	Required element for SCCDA. Establishes whether SCC is present	A
Location and size of each cluster	After coating removal	Required element for SCCDA. Used to establish correlation of location with other parameters measured.	A
Crack length and depth measurements	After coating removal	Required element for SCCDA. Used to establish significance of cracking and determine whether there is an immediate integrity concern.	A
In situ metallography	After coating removal	Used to establish type of SCC	B
Photograph clusters	After coating removal	Required element for SCCDA. Used to confirm crack measurements.	A
Wall thickness	After coating removal	Required element. Used in integrity assessments and field site verification.	A, D
Measure pipe diameter	After coating removal	Required element. Used in integrity assessments and field site verification.	A, D

A = Required element for SCCDA
B = Optional (Likely useful in SCCDA model development)
C = Optional (Might be useful in SCCDA model development)
D = Useful background information or information used in other analyses

5.3 The Direct Examination step requires excavations to expose the pipe surface so that measurements can be made directly on the pipeline and in the immediate surrounding environment at pipe depth.

5.4 The order in which excavations and direct examinations are made is discretionary, but should take into account safety and related considerations.

5.5 The Direct Examination step includes the following activities:

- Verification of the field sites selected based on the pre-assessment and indirect inspection steps
- Excavation and data collection at the dig sites
- Analysis and documentation of the type of cracking if SCC is detected
- Evaluation and documentation of the severity of cracking if SCC is detected

5.6 Field Site Verification

5.6.1 Prior to beginning excavation, the aboveground parameters used for the excavation site selection shall be field verified. The nature of these parameters depends on the selection criteria used.

5.6.2 When pipeline construction data, a terrain-based predictive model, or other data is used for site selection, the actual conditions shall be field verified. The topography is normally confirmed through visual observation. The soil and drainage can be confirmed by hand auguring.

5.6.3 When site selection is based on the presence of coating faults or areas of potential corrosion activity (identified by techniques such as DCVG or CIS) the location shall be field verified by measurement from a known reference point identified during the survey or by repeating the measurements in the area of the planned excavation site.

5.6.4 When in-line inspection data is used for excavation site selection, the location of the excavation site with respect to aboveground features on the pipeline such as aboveground markers, valves or casings/casing vents should be field verified and compared with the ILI data.

5.7 Excavations and Data Collection

5.7.1 A reference location for each excavation should be selected so that data can be recorded in an organized fashion and inspection and direct examination results can be directly compared.

5.7.2 Before conducting excavations, minimum requirements for consistent data collection and record-keeping shall be defined. Minimum requirements shall be based on sound engineering judgment and may depend on characteristics including operation of the pipeline, the pipeline network, or the specific location. The Dig Data Sheet form provided in Procedure PS-03-01-242: “Dig Data Sheet” shall be used to collect the minimum data set, such as the elements shown in Table 4. Use of the Dig Data Sheet form assures a consistent methodology is applied to data collection. The Dig Data Sheet provides for collection of the following information which is further discussed below. Also refer to Section 6.0 of this procedure for information on data collection methods.

- Measurement of pipe-to-soil potentials
- Measurement of soil resistivity
- Assessment of type of coating
- Assessment of overall coating condition
- Measurements of coating disbondment
- Electrolyte samples beneath disbonded coatings
- Photographic documentation

A. Pipe-to-soil potentials are commonly measured immediately following pipe excavation by placing a reference electrode in the bank of the excavation around the pipe at both ends of the excavation. With the use of interrupters, both “on” and “off” potentials may be obtained. Typically, this data is used to aid in assessing the level of CP at the pipe. Caution should be used in interpreting the results of the measurements because the excavation of the pipe alters the electric field in the soil around the pipe.

B. Soil resistivity measurements are used to assess the corrosiveness of the soil, which can be related to the concentration of soluble ions in the soil and soil moisture content. The most common methods for measuring soil resistivity are the Four-Pin Method, Soil Box Method or the Collins Method.

C. If a predictive model is to be employed or developed, soil and groundwater sample collection may be useful. The main purpose of collecting soil and groundwater samples is to further develop an understanding of the environmental factors associated with SCC. Parameters such as soil mineralogy and soil texture can influence the level of oxygenation (aerobic versus anaerobic), soil drainage, and the tendency to promote coating disbondment. The general chemistry and biological parameters can be input in a predictive model for SCC. Examples of chemical parameters that are analyzed include pH, conductivity, cation and anion concentration, oxidation-reduction potentials, total carbonates and organic carbon. All analyses for soil, groundwater, mineralogy, and textures should follow standardized sampling, storage, transportation and laboratory practices. Section 6, Direct Examination - Data Collection Methods, provides details for obtaining test samples.

D. The coating system should be identified base on visual observation and recorded. If possible, also determine other characteristics of the coating system, such as the type of surface preparation, whether shop coated or over-the-ditch coated, type of primer, number of coats, reinforcement, and outer wrap. If the type cannot be positively identified, a coating sample should be obtained and analyzed. Analysis of the coating can provide information pertaining to type as well as electrical and physical properties (for example, resistivity, gas permeability, etc.). The samples can also be used to conduct microbial tests.

E. The overall coating condition and extent of coating disbondment shall be assessed and recorded. Following are characteristics of different coating conditions:

- **Excellent Coating:** Very good adhesion with less than 1% disbondment and occasional holidays. No electrolyte beneath the coating. Very minor to nonexistent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Uniform thickness of asphalt and coal tar coatings with no evidence of wrinkling.

- **Good Coating:** Good adhesion with 1% to 10% disbondment and scattered holidays. Isolated locations with electrolyte beneath the disbonded coating. Minor intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Isolated evidence of poor adhesion, wrinkling, or other damage associated with soil stress on asphalt and coal tar coatings.

- **Fair Coating:** Fair adhesion with 10% to 50% disbondment and scattered to numerous holidays. Intermittent locations with electrolyte beneath the disbonded coating. Intermittent tenting (on DSAW and girth welds) or wrinkling of tape coatings. Random areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Brittle asphalt and coal tar coatings.

- **Poor Coating:** Poor adhesion with 50% to 80% disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.

- **Very Poor Coating:** Very poor adhesion with greater than 80% disbondment and numerous holidays. Corrosion deposits at holidays and beneath disbonded coatings. Numerous locations with electrolyte beneath the disbonded coating. Continuous tenting (on DSAW and girth welds) or wrinkling of tape coatings. Large areas of wrinkling or other damage associated with soil stress on asphalt and coal tar coatings. Very brittle asphalt and coal tar coatings.

F. Areas of coating disbondment are commonly identified and documented in SCC dig programs. The size and shape of the area of disbondment and the distance from the girth weld and the distance of clock position from the top of the pipe are measured and recorded.

G. Electrolyte samples beneath disbonded coatings may be obtained using a syringe in cases in which sufficient liquid for sampling is present. Typically, the pH of the electrolyte is measured in the field and the sample is placed in an evacuated sample vial and returned to the laboratory for analysis. Measurement of the pH of a solution in the field is important because environmental contamination and ongoing chemical reactions within the sample can alter the pH prior to laboratory analysis. Litmus paper is commonly used for the field pH measurements. The laboratory analyses on each electrolyte sample should include pH and, if sample volumes permit, conductivity and general chemical analysis of the ionic composition. In some cases, samples are also analyzed for microbial activity.

H. It may be important to obtain photographic documentation of the excavation site prior to coating removal. This should include the pipe prior to coating removal, the sidewalls of the ditch, and the overall excavation site. This information can be used to verify the topography, drainage and soil type as well as the coating condition.

5.8 Coating Removal

5.8.1 The coating in the disbonded areas shall be removed so that the pipe surface can be examined. The method of coating removal is a function of the coating type.

5.9 Data Collection and Other Activities Following Coating Removal

5.9.1 Data measurements and related activities following coating removal are listed below:

A. The presence and nature of any deposits or corrosion products on the pipe surface are described and photographed after coating removal. Samples also may be obtained for analysis. Field-test kits are available for qualitative analysis on site. Different corrosion deposits have been correlated with the two types of SCC. Near-neutral pH SCC has been associated with $FeCO_3$ (siderite) while high pH SCC has been associated with $NaHCO_3$ (nahcolite) or Fe_3O_4 (magnetite). If moisture is present on the pipe surface beneath disbonded coatings, the pH should be measured using litmus paper and recorded. The color, texture, composition and distribution of the corrosion products and deposits should be documented.

B. All corrosion defects shall be documented. Additional cleaning and pipe surface preparation shall be made prior to depth and morphology measurements.

C. Corrosion defects shall be mapped and measured in accordance with Section 6.0, Direct Examination - Data Collection Methods.

D. It is important to obtain photographic documentation of corrosion defects for future reference, with location references (for example, distance downstream from reference girth weld and clock orientation).

5.9.2 Pipe Preparation for Magnetic Particle Inspection (MPI)

A. The objective of the pipe preparation process is to remove coating residue and corrosion deposits in order to enable inspection of the pipe surface for cracks.

B. In order to optimize the effectiveness of MPI techniques, the steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products, and coating remnants that could prevent contact of the magnetic particle medium with the steel surface.

C. The mobility of the magnetic particles must not be limited by an overly rough surface that interferes with the MPI method used.

D. The surface preparation must not mechanically damage the surface such that any cracks present are masked.

E. The employment of MPI requires adequate surface preparation in accordance with ASTM E 709. When mechanical cleaning methods are used, care should be taken to perform the least aggressive preparation needed consistent with inspection of the surface.

F. For disbonded areas of coating that can be removed without the use of a blasting medium, solvent cleaning may be adequate. Adhered coating need not be removed for SCC inspection because SCC does not occur at locations where the coating is adhered to the pipe surface.

G. Pipe cleaning that requires the use of a wire brush or a blasting medium such as water, slag or other abrasives should be performed with the goal of removing disbonded coating in a manner that minimizes alteration of the pipe surface.

H. There are several techniques for surface preparation prior to wet MPI of SCC crack clusters: high-pressure water blast, abrasive blasting with walnut shells, abrasive blasting with slag, and power wire brushing. Table 5 summarizes the advantages and disadvantages of these techniques. Table 6 provides a comparison of surface preparation techniques versus detection limits and cost.

TABLE 5

Summary of Surface Preparation Techniques Advantages and Disadvantages

Surface Preparation Technique	Description	Advantages	Disadvantages
Water Blasting	Uses potable at very high pressure (>25,000 psi)	▪ Does not create a surface roughness and therefore eliminates any concern for crack masking ▪ Can be used with additives to remove greasy solutions	▪ Does not always remove tenacious corrosion products ▪ Only potable water can be used in the high pressure equipment and potable water resources are not reliable ▪ Excavation site becomes muddy ▪ Freezing concerns in winter ▪ Safety concerns with high-pressure discharge ▪ Limited availability of equipment
Abrasive blasting with walnut shells	Walnut shells are used as an abrasive medium employing the same equipment common to sand and slag abrasive blasting	▪ As an abrasive, walnut shells are relatively soft, therefore masking is very unlikely ▪ Skilled operators are readily available	▪ Does not always remove tenacious corrosion products ▪ Leaves an oily residue that may affect subsequent pipe recoating effectiveness (residue can be removed with cleaning agents) ▪ Possible allergic reactions
Abrasive blasting with slag	Relatively hard abrasives such as coal slag are filled into pressurized pots, which discharge the abrasive through a hose and nozzle at a pressure of approx-imately 100 psi measured at the nozzle	▪ Provides the highest level of steel cleanliness of all techniques ▪ Skilled operators and materials are readily available ▪ Subsequent surface preparation for recoating requirements is minimized	▪ User must be conscientious of selecting the appropriate abrasive grade and blast settings in order to ensure small cracks are not masked
Power wire brush 180 grit flapper wheel	Electric or pneumatic grinding tools are fitted with specialized rotating disks or wheels which mechanically clean by abrasion and remove base material	▪ Simple to use equipment with little maintenance and refuse	▪ Consistent cleaning quality across inspection surface can be difficult to achieve ▪ User must be conscientious in selecting the appropriate abrasive grade in order to control masking of cracks

TABLE 6
Comparison of Surface Preparation Techniques vs. Detection Limits and Cost

Surface Preparation Technique	Detectability	Crack Sizes Detectable Using WFMPI (inches)	Crack Sizes Detectable Using BWMPI (inches	Cost Ranking (1 = most expensive)	Cleaning Rate
Water Blasting	Excellent, as long as all corrosion products, etc., can be removed	0.04	0.04 to 0.08	4	Satisfactory cleaning rate but cannot remove some corrosion deposits
Walnut shells	Excellent, as long as all corrosion products, etc., can be removed	0.04	0.04 to 0.08	3	Good cleaning rate but cannot remove some corrosion deposits
Slag	Very good	0.04 to 0.08	0.04 to 0.08	2	Overall, provides best cleaning rate of all techniques. Somewhat dependent on abrasive sharpness
Wire wheel, etc.	Satisfactory, very minor (0.04 to 0.08 inch) cracks can be masked	No data	0.08 to 0.12	1	Slow for large areas, but removes tenacious substances

5.9.3 Magnetic Particle and Dye Penetrant Inspection

A. Following cleaning, the pipe surface shall be inspected for crack-like defects using magnetic particle inspection (MPI) or dye penetrant inspection. The inspections shall be conducted using manufacturer's instructions, specifications and recommendations for the particular inspection tool.

B. Four MPI techniques are available to detect surface-breaking defects on the external surface of pipelines:

- Dry powder (DP)
- Wet visual MPI (WVMPI)
- Wet fluorescent MPI (WFMPI)
- Black and White MPI (BWMPI)

C. Dry and wet magnetic particle inspection (MPI) methods such as dry powder (DPMPI), wet visual (WVMPI), wet fluorescent (WFMPI) and black-on-white contrast (BWMPI) can be used to detect external surface-breaking pipe defects after the pipe surface is cleaned. All four techniques are proven methods to detect external SCC. The Company should demonstrate that the technique(s) selected and the protocols used are effective in detecting SCC. ASTM E 709 describes MPI techniques to detect cracks, including SCC in ferro-magnetic materials, and is commonly referenced to develop, monitor and evaluate inspection procedures.

D. The method of magnetization of the pipe surface has been experimented with, but the most practical and easiest to use is a hand yoke. Alternating current (AC) and direct current (DC) hand yokes are available to complete an MPI inspection. The most commonly used yoke for SCC investigations is the AC type of yoke because it specifically detects surface-breaking defects.

E. The most critical factor during the SCC inspection process is the experience of the technician to evaluate and classify the indications detected on the pipe surface. The technician needs to clearly demonstrate a knowledge and ability to discriminate SCC from those indications resembling SCC such as toe-weld indications, delaminations, undercut, laps, slivers, or scabs.

F. Magnetic particle inspection and dye penetrant inspection provide only an indication that the stress corrosion cracking threat is present. An ultrasonic shear wave tool can be used to assess the size and extent of the crack. Sizing accuracy using shear wave technology is limited by the number of sensors and complexity of the crack colony, and is degraded by the presence of inclusions and impurities in the pipe wall.

G. Table 7 provides a comparison of the four types of MPI methods most commonly used for crack detection.

TABLE 7
Advantages and Disadvantages of MPI Methods

MPI Method	Ultimate Sensitivity	Advantages	Disadvantages
Dry Powder (DPMPI)	0.08 to 0.19 in. long defects	▪ Maximum portability ▪ Crack replicas can be obtained	▪ Regardless of pipe cleaning technique, this technique when use with an AC yoke yields the lowest sensitivity of the MPI techniques ▪ Must have a very clean surface; dampness affects particle distribution and mobility ▪ Subject to climate limitations (i.e., wind can blow the powder around and create a health and safety hazard for the technicians)
Wet Fluorescent (WFMPI)	0.04 in. long defects	▪ Highest degree of sensitivity ▪ Dry concentration plus a water conditioner mix readily with water	▪ Longer set-up time ▪ Requires more inspection equipment compared to other methods ▪ Difficult to document SCC due to darkness required during inspections ▪ Seasonal conditions can cause overheating and malfunctions of equipment ▪ Photography can be done but more difficult compared with BWMPI or WVMPI methods due to darkness required during inspection. ▪ Safety hazards in wet, sloppy excavation sites ▪ Subject to climate limitations (i.e., wind can make it difficult to keep the light retarding tarp in place and high ambient temperatures can make it very hot and uncomfortable for the technicians beneath the light-retarding tarp)
Wet Visual (WVMPI)	0.04 to 0.08 in. long defects	▪ Requires less set-up time than WFMPI or BWMPI ▪ Requires less MIP equipment than WFMPI ▪ Easier to photograph SCC indications than with WFMPI or DPMPI	▪ Flux properties are affected by freezing and low temperatures ▪ Photography not as easy as with BWMPI
Black-and-White Contrast (BWMPI)	0.04 to 0.08 in. long defects	▪ Requires less MPI equipment than WFMPI. Makes it easier to photograph SCC indications, weather permitting	▪ Contrast paint and flux are pre-mixed; therefore, a larger supply is required compared with the concentrated form of dry particles mixed with solvent utilized for the WVMPI and WFMPI methods ▪ Paint and flux properties affected by freezing and low temperatures. Aerosols can pose a health and safety hazard ▪ Applying the white contrast can be time-consuming

5.9.4 Crack Cluster Evaluation

A. Following magnetic particle or dye penetrant inspection, each detected crack cluster shall be documented and evaluated for safety.

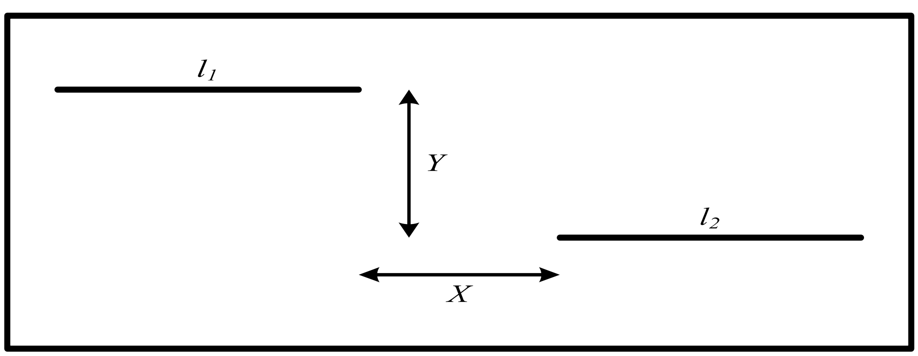
B. Each detected crack cluster shall be given a unique identifier and the location of the center of the colony should be identified relative to a reference point such as a weld and a clock position. Information that shall be obtained for each detected crack cluster follows.

C. The axial length is the total length of the colony in the axial direction. The circumferential length is the length of the colony in the circumferential direction. The length of the colony is the maximum length of the colony, which might be different from the axial or circumferential length, depending on the colony orientation. The width of the colony is the dimension of the colony perpendicular to the length direction.

D. Cracks are defined to have interlinked if they physically have joined (coalesced) to form one longer crack.

E. Crack interaction is dependent on the circumferential and axial separation between individual (or interlinked) cracks and is calculated as follows:

1. Two neighboring cracks, as illustrated below, are defined as interacting if their circumferential spacing Y (in inches) is as indicated in equation (1):



$$Y \leq 0.14 \frac{(l_1 + l_2)}{2} \quad (1)$$

and if their axial spacing, X (in inches), is as illustrated in Equation (2):

$$X < 0.25 \frac{(l_1 + l_2)}{2} \quad (2)$$

Where l_1 and l_2 are the individual crack lengths in inches.

F. The maximum crack length is the total length of the longest interacting and interlinking crack.

G. An SCC cluster is assessed to be “significant” if the deepest crack, in a series of cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that could fail at a stress level of 110% of SMYS. A significant crack potentially could fail in a pressure test and therefore is considered to be an eventual integrity threat to the pipeline. The presence of extensive and significant SCC typically triggers an SCC mitigation program.

H. The maximum crack depth is important in evaluating whether the cracking is significant and in estimating the failure pressure. The maximum depth of stress corrosion cracks in a cluster is difficult to measure using indirect techniques such as ultrasonic test (UT) because of interaction of the signal with the cracks in the cluster. Grinding or buffing, in conjunction with MPI, is a method that is commonly used to determine the maximum depth of the longest interlinked crack at an excavation site. It is then typically assumed that all other cracks in the excavation are less deep. This method can also be used to evaluate the accuracy of other crack-depth measurement techniques. If grinding is to be performed on a pressurized line, the initial wall thickness shall be determined by UT, and a safe wall thickness must be maintained at all times during grinding.

I. The average circumferential separation of adjacent cracks is important to document because it has been found that sparsely spaced cracks are more likely to align to form significant cracks.

Adjacent cracks in clusters of densely spaced cracks tend to relieve tensile stresses at the tips of nearby cracks and are less likely to be integrity concerns.

J. In situ metallography is used to examine the microstructure of the steel and the path (intergranular versus transgranular) of the stress corrosion cracks. This information can be used to establish the type of SCC: intergranular cracking indicates high-pH SCC and transgranular cracking indicates near-neutral pH SCC. In situ metallography requires a portable microscope or replication, and it should be performed by personnel qualified in metallographic preparation and the analysis of microstructures.

K. The wall thickness, in conjunction with the dimensions of the interlinked cracks and mechanical properties of the wall joint, is used to estimate failure pressure of the pipe segment containing the SCC. Ultrasonic measurements should be made by qualified personnel in accordance with a specification and a written procedure. The written procedure shall be developed and approved by personnel with sufficient qualifications in the specific method of inspections to be used. For the purpose of wall thickness measurement using ultrasonic techniques, an ASNT certification shall not be required.

L. It is useful to photograph crack clusters for archival purposes and for subsequent reevaluation of the cracking in cases in which questions arise concerning the field assessment of the cracking.

5.10 Analysis of Type of Cracking

5.10.1 Indications of cracking detected by this procedure can be the result of several causes, including near-neutral pH SCC, high pH SCC, mechanical damage, or even non-injurious mill imperfections.

5.10.2 The necessity for and type of mitigation activity are dependent on the type of the cracking present.

5.10.3 The presence of cracking in clusters distinguishes SCC from other forms of cracking.

5.10.4 Near-neutral pH SCC frequently is associated with light surface corrosion of the pipe. High pH SCC usually is not associated with obvious external corrosion.

5.10.5 In some cases, in situ metallography might be required to confirm the type of SCC. High pH SCC is intergranular and typically is branched with little evidence of corrosion of the pipe outside surface and crack walls. Near-neutral pH SCC is transgranular and typically is un-branched, usually with evidence of corrosion of the pipe outside surface and crack walls. Near-neutral pH SCC tends to be wider than high-pH SCC.

5.11 Evaluation of the Severity of Cracking

5.11.1 The severity of the stress corrosion cracking indications shall be evaluated and documented. MPI and dye penetrant inspections only provide indication that a crack exists. An ultrasonic shear wave tool can provide information about the breadth and depth of the cracks.

5.11.2 The SCCDA process helps find representative SCC clusters on a pipeline segment, but it might not find all such defects on the segment.

5.11.3 If SCC clusters that exceed allowable limits are found, it should be assumed that other similar defects might be present elsewhere in the segment.

5.11.4 When stress corrosion cracking is detected, Section A3.4 of Appendix A of ASME B31.8S shall be followed. The requirements of Section A3.4 are included in Section 7.0 of this procedure.

6.0 DIRECT EXAMINATION – DATA COLLECTION METHODS:

6.1 Safety Considerations

6.1.1 Excavating and working around pressurized pipe involves potential risks. Appropriate safety precautions, including adherence to OSHA regulations and safety procedures, shall be followed.

6.2 Pipe-to-Soil Potentials

6.2.1 Pipe-to-soil potentials should be measured with the reference electrode placed in the bank of the excavation, at various positions around the pipe, in the side of the excavation, and/or at the surface. These measurements are for information purposes since, with the excavation of the pipe, the electric field around the pipe has been altered. However, pipe-to-soil potentials at the point of excavation may help to identify dynamic stray currents in the area.

6.3 Measurement of Soil Resistivity

6.3.1 Four-Pin Method

A. When this method is used, four pins are placed at equal distances in the earth in a straight line as shown in Figures 2 and 3. The spacing of the pins (shown as "a") must equal the depth to which the soil resistivity is of interest. A current is caused to flow between the two outside pins (C1 and C2). The voltage drop created in the earth by this current flow is measured between the two inside pins (P1 and P2).

FIGURE 2: Four-Pin Method with Voltmeter and Ammeter

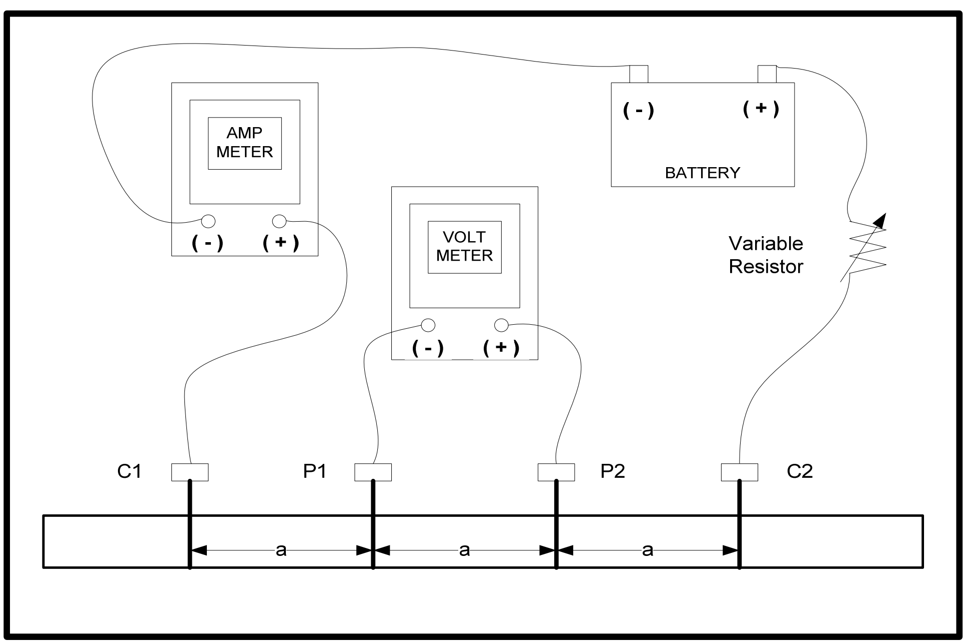
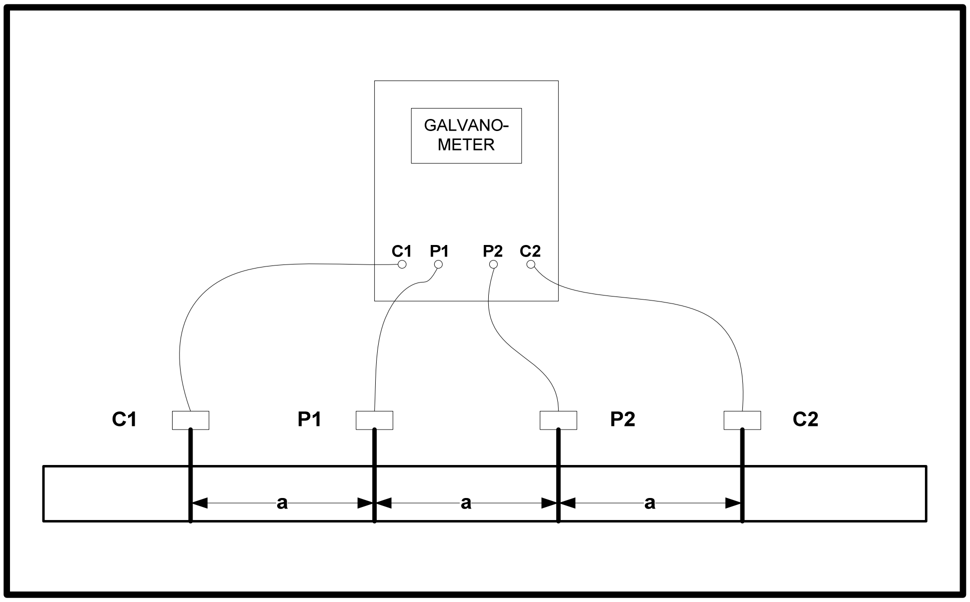


FIGURE 3: Four-Pin Method with Galvanometer



B. There are two distinct differences in the apparatus used with the four-pin method. The first (Figure 2) is performed with an ammeter and voltmeter combination. This combination uses DC to produce and measure the voltage drop in the earth that is measured between the inside pins (P1 and P2). The second (Figure 3) uses a galvanometer that generally uses a vibrator circuit. The use of a galvanometer is believed to be more accurate because no polarization of the electrodes should occur. In practice, both configurations should give accurate and reproducible results provided that excessive currents and voltages are not used.

C. Care and judgment must be exercised under certain conditions in which pin contact resistance with the earth may be high. High resistance at the pin contacts may affect the measurement accuracy, and with the AC equipment, the galvanometer does not zero correctly. This condition generally occurs during dry weather periods and in locations of relatively high soil resistivity. When using the galvanometer, the needle should swing to both sides of zero. Wetting the soil around the current pins with water or a water/soap solution may eliminate or reduce the effects of this condition. Pins should be inserted into the ground as little as possible and still obtain readings. Pins should never be inserted to a depth greater than 10% of pin spacing. Equation (3) below is based on a theoretical point contact.

D. It has been determined that the average soil resistivity to a depth equal to the spacing between the two inside pins is given by Equation (3):

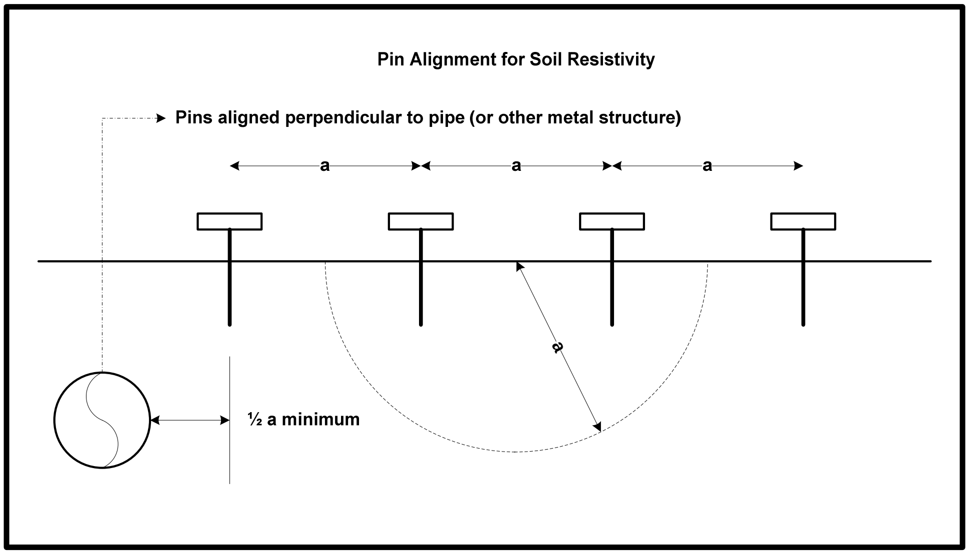
$$\rho = 191.5aR \tag{3}$$

Where:
ρ = resistivity in ohm-feet
a = pin spacing in feet
R = resistance in ohms = V/I
V = potential in volts
I = current in amperes

E. When a galvanometer type of instrument such as that in Figure 3 is used, the resistance “R” can be read directly. The galvanometer-type instrument utilizes a Wheatstone bridge circuit and when balanced to zero, shows “R” directly on the balancing controls or as in this case, may require a simple multiplication between the control indications on the instrument.

F. The four-pin method is used for most field resistivity measurements of soils. Soil resistivity determined in this manner is the average (or apparent) soil resistivity of a hemisphere of earth. This is illustrated in Figure 4, which shows that the radius of this hemisphere is distance “a” (the distance between the inside pins). If a steel pipeline or other metallic structure lies within the sphere to be measured, measurement errors result. To avoid these errors, readings should be taken perpendicular to the pipeline with the nearest pin no closer than ½ “a” to the pipe (or any other metallic structure). The pin spacing must be of equal distance to obtain accurate results. For general use, a pin spacing of 5 ft. 3 in. is convenient because this results in a factor (191.5 times “a”) being equal to 1,000.

FIGURE 4: Pin Alignment Perpendicular to Pipe



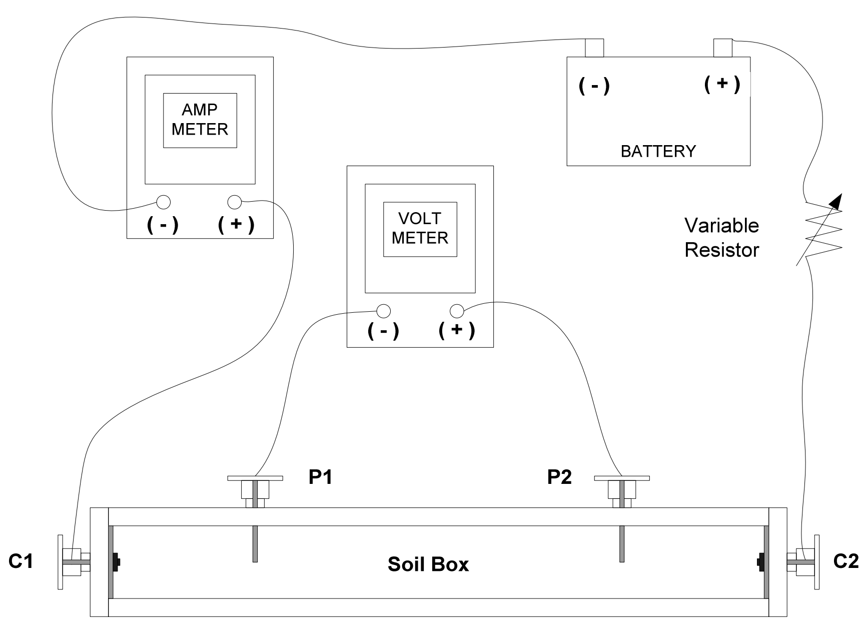
G. Readings taken with successively greater pin spacing give a profile of the average soil resistivity of an increasingly larger hemisphere, and thus to a greater depth. It should be noted in the analysis of increasingly larger pin spacing that in the case of relatively the same soil resistivity with depth, the soil resistivity as measured decreases slightly. An increase in the measured resistivity tends to suggest that the soil resistivity is increasing with depth more than is indicated by the measured amount. The opposite is true for large reductions in resistivity. These tend to indicate a lower than measured resistivity with depth. For each successively greater pin spacing, a greater depth in the soil is included in the measurement, but because this is a surface type of measurement method, it also includes the resistivity of the soil layers above.

6.3.2 Soil Box Method

A Figure 5 shows another use of the four-pin method in conjunction with a soil box. The soil box is primarily used for resistivity measurements during excavations or boring. The connection of the instrument and test procedure is essentially the same as those illustrated earlier. They are suited for testing resistivity at varying levels of depth during vertical bores because they allow measurement of various strata of soil as the boring progresses.

Also, data can be measured from soil taken at pipeline depth during the installation of a new pipeline. Accuracy of a soil box depends on how closely the original conditions are recreated in the soil box, e.g., compaction, moisture, etc. The soil box has a multiplier for obtaining soil resistivity. Always refer to the manufacturer's instructions for use of a multiplier.

FIGURE 5: Four - Pin Method with Voltmeter and Ammeter

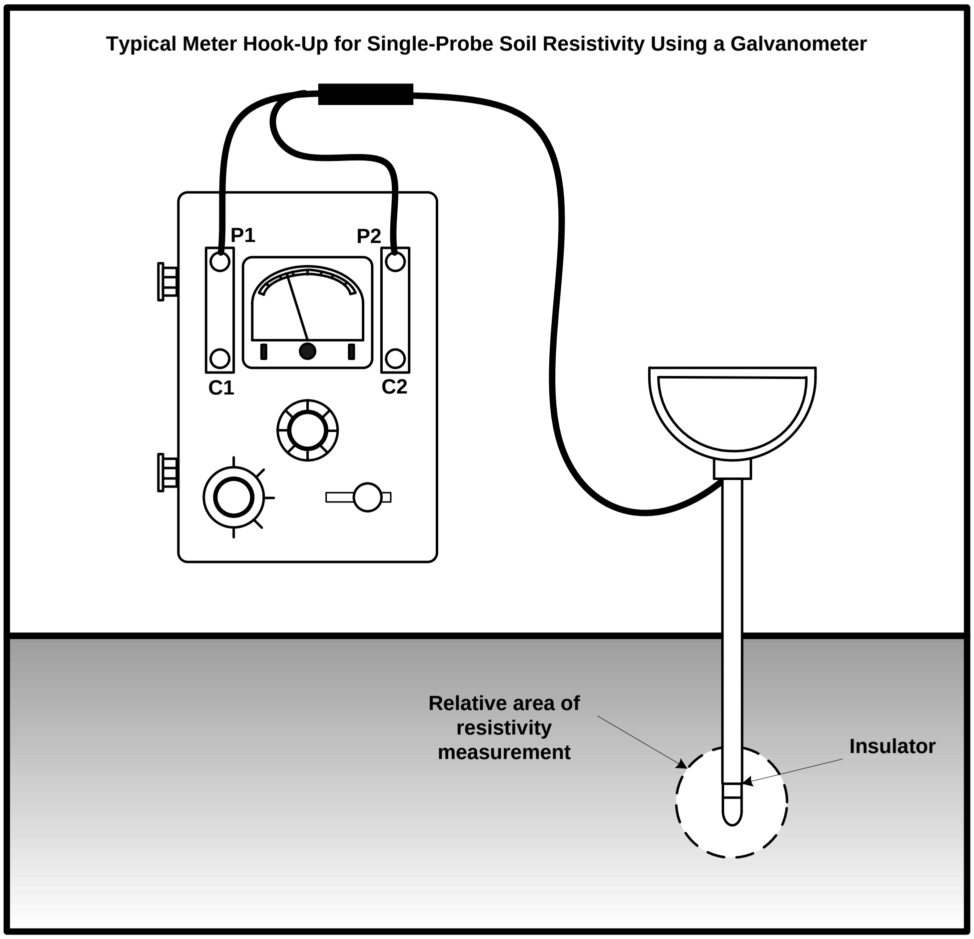


Typical Meter Hook-up for Soil Box Resistivity Using Ammeter and Voltmeter with Battery and Controls

6.3.3 Single-Probe Method

A. The single-probe method is a two-point resistivity measurement. The typical probe is shown in Figure 6 with an audio-type instrument. A resistance measurement is made between the tip of the probe and the shank of the probe rod after insertion in the soil. Modern models generally have an audio receiver hooked into the Wheatstone bridge. This allows the operator to hear an audible AC tone until the bridge circuit is balanced and a null occurs. At the point of null, the resistance can be read from the pointer on the instrument adjustment dial.

FIGURE 6: Single-Probe Method



B. The resistivity measured by this method is only representative of the small volume of soil around the tip of the probe and should not be thought of as typical for all of the total soil in the area in question. Multiple measurements within the area of interest increase the validity of this method by increasing the sample size if the point of interest can be reached with the probe. Single-probe measurements are generally used for comparative purposes or in excavations to locate anodes in the lowest-resistivity soil. This method is also useful when the close proximity of other underground metal structures make the use of the four-pin method impractical.

C. There are also several three-pin techniques for measuring soil resistivity. These are typically used for measuring resistivity at depths that are greater than those at which the four-pin method works. The four-pin method is limited in depth due to the ability of the meters to read a smaller and smaller resistance.

6.4 Soil and Water Sample Collection

6.4.1 Soil Samples

A. Soil samples should be collected with a clean spatula or trowel and placed in an 8-ounce plastic jar with a plastic lid. The sample jar should be packed full to displace air. Tightly close the jar, seal with plastic tape, and using a permanent marker, record sample location on both the jar and the lid.

6.4.2 Groundwater Samples

A. Water samples should always be collected from the open ditch when possible. Completely fill an 8-ounce plastic jar, seal, and identify location with a permanent marker on both the jar and the lid.

6.4.3 Laboratories

A. Soil-testing laboratories that will be performing the testing should be specifically equipped with wet laboratory facilities designed for soil testing. Samples should be tested for the following:

1. Type Classification: classify soil type by the United Soil Classification System (USCS), U. S. Department of Agriculture standards, or other standards.

2. Moisture Content: determine the moisture content of the soil using a modified version of AASHTO Method T 265. In this procedure, measure a mass of soil and then oven dry to 230˚ ± 9˚ F. for a minimum of 16 hours. Measure the mass of the cooled sample and calculate the moisture content as percent of dry weight from the change in mass.

3. Sulfide Ion Concentration: prepare a fresh 50% soil-water suspension by weight using deaerated water immediately after removing the soil from the sample jar. Add sulfide anti-oxidant buffer solution. Test with a selective ion electrode and a double-junction reference electrode. Refer to EPA 376.1.

4. Conductivity: use a fresh amount of soil and prepare a 50% soil-water suspension by weight. Let the solution react for minimum of one-half hour. Insert the probe from the conductivity meter into the soil-water suspension and record the results. Refer to ASTM D 1125.

5. pH: Prepare a 50% soil-water suspension by weight, let react for one hour, and measure using a separate pH electrode and a single junction reference electrode. Refer to ASTM D 4972.

6. Chloride Ion Concentration: prepare a 50% soil-water suspension by weight, add ionic strength adjustor in accordance with instrument manufacturer's recommendations, and test with ion-selective electrode. Refer to ASTM D 512.

7. Sulfate Ion Concentration: Prepare a 50% soil-water solution and pipette 50 mL of the water extract into a beaker. Add 50 mL of methanol-formaldehyde. Titrate with lead perchlorate. Refer to ASTM D 516.

6.5 pH Testing

6.5.1 If a liquid is present beneath the coating, take a sample using a syringe or cotton swab following procedures described above for testing purposes.

6.5.2 Test the pH of the liquid using hydrion paper or the equivalent. Carefully slice the coating to a length to allow the test paper to be slipped behind the coating. Press the coating against the pH paper for a few seconds and then remove the pH paper. Note and record the color of the paper in relation to the chart provided with the paper.

6.6 Microbiologically Influenced Corrosion (MIC) Analysis

6.6.1 MIC analyses should be performed on corrosion products when MIC is suspected. These tests should be performed to determine whether microbial activity could be contributing to the observed corrosion. The tests should be performed in accordance with the procedures in kits designed for analyzing MIC, provided by the manufacturers of well-known MIC kits. One kit can be used to analyze qualitatively for the presence of carbonate (CO3+2), sulfide (S-2), ferrous iron (Fe+2), ferric iron (Fe+3), calcium (Ca+2), and hydrogen (H+1, pH) ions while others only analyze for bacteria.

6.6.2 Corrosion Product Analysis

A. After the pipe is exposed, immediately sample and test the soil and any suspected deposits. Carefully remove the coating around the suspected area of corrosion using a knife or similar instrument. Sample contamination must be kept to a minimum. Therefore, avoid touching the soil, corrosion product, or film with hands or tools other than those to be used in sample collection and provided with the test kits. Samples should be obtained from the following areas:

- Undisturbed soil immediately next to the exposed pipe steel surface or at an area of coating damage
- A deposit associated with visual evidence of pipe corrosion
- Liquid trapped behind the coating.

B. Collect a sample of soil, deposit, film, or liquid from the area of interest. Use only a clean knife or spatula provided with the test kit. The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the back side of the coating. In all cases, note the color and type of sample. Carefully transfer the sample to the test kit vial for testing. Follow the detailed procedure given in the kit instruction sheets. For comparison purposes, obtain a reference sample taken at least 3 feet from the previous collection site.

6.6.3 The form of the corrosion pits associated with MIC is reasonably distinctive. These features can be observed in the field with the unaided eye or a low-power microscope or magnifying glass.

6.6.4 After any films or products sampled above have been obtained from a corroded area, remove the remaining product using a clean spatula or knife, being careful not to scratch the metal. Clean any remaining material with a clean, dry, stiff brush, such as a nylon-bristle brush. Do not use a metal brush if possible, because the metal bristles can mar the pit features. If not all of the product can be removed with this method, use a brass bristle brush in the longitudinal direction only. Dry the area with an air blast or an alcohol swab. A shiny metallic surface of the pit suggests the possibility of active corrosion. However, judgment must be used to differentiate this condition from one created by scraping the steel surface with a metallic object, such as the knife or spatula used to clean the surface or to obtain the sample product.

6.6.5 Examine the newly cleaned corroded area first visually with the unaided eye. Then use a low-power magnifying lens at 5X to 50X to examine the detail of the corrosion pits. MIC often has the following features:

- Large craters up to 2 to 3 inches or more in diameter
- Cup-type hemispherical pits on the pipe surface or in the craters
- Craters or pits sometimes surrounded by uncorroded metal
- Striations or contour lines in the pits or craters running parallel to longitudinal pipe axis (rolling direction)
- Tunnels sometimes at the ends of the craters, also running parallel to the longitudinal axis of the pipe.

7.0 POST ASSESSMENT:

7.1 The objectives of the post assessment step are to:

- Determine whether general SCC mitigation is required
- Prioritize remedial action for defects that are not removed immediately
- Define reassessment intervals

- Evaluate the effectiveness of the SCCDA approach

7.2 Mitigation

7.2.1 Discrete Mitigation is selected to address isolated locations at which "significant" SCC has been detected during the course of the field investigation program. Typically, this form of mitigation is limited to areas where the affected pipe length is relatively short – less than 300 feet in length. The mitigation options are:

- Repair or removal of the affected pipe length.
- Hydrostatically testing the pipeline segment.
- Performing an engineering critical assessment to evaluate the risk and identify further mitigation methods.

7.2.2 General mitigation is selected to address pipeline segments when the risk of "significant" SCC could potentially be widespread within a particular segment or segments of a pipeline. Typically, this form of mitigation is used to address areas in which the affected pipe length is relatively long. The mitigation options include:

- Hydrostatic testing of affected pipeline segments
- In-Line Inspection when appropriate tools are available
- Extensive pipe replacement
- Recoating

7.3 MPI and Dye Penetrant Results and Subsequent Action

7.3.1 No SCC indication

A. Re-coat disbonded area using appropriate coating and method in accordance with Company Procedures.

B. Evaluate interval schedule for additional bell hole inspections if necessary

7.3.2 SCC indication: when SCC indications are detected, one of the following mitigation methods shall be used.

A. Repair or remove SCC indications using methods identified in Procedure PS-03-01-254: "Threat Prevention and Repair Chart".

B. Hydrostatically test the subject pipeline segment.

C. Perform an engineering critical assessment to evaluate the risk and identify further mitigation methods

7.4 Hydrostatic (Pressure) Testing

7.4.1 Hydrostatic testing is one of the methods available for mitigating stress corrosion cracking.

7.4.2 If the pipeline segment experiences an in-service leak or rupture which is attributed to SCC the particular segment shall be subjected to a hydrostatic test within 12 months. A documented hydrostatic retest program shall be developed for this pipeline segment.

7.4.3 Pressure testing for SCC shall be conducted using only hydrostatic testing. Pneumatic testing with mediums such as air or gas is NOT permitted by ASME B31.8S

7.4.4 Hydrostatic testing conditions for SCC mitigation have been developed through industry research to optimize the removal of critical sized flaws while minimizing growth of subcritical sized flaws.

7.4.5 Pressure tests shall be conducted in accordance with Book 2, Manual of Construction Specifications, Procedure 47: “Pipeline Pressure Testing”.

7.4.6 Recommended hydrostatic test criteria are:

A. High point test pressure shall be equivalent to a minimum of 100% SMYS

B. Target test pressure shall be maintained for a minimum period of 10 minutes

C. Upon returning the pipeline to gas service, a flame ionization survey shall be performed. (Alternatives may be considered for hydrostatic test failure events due to causes other than SCC).

7.4.7 Test Results and Subsequent Actions

A. No Leaks or Failures - if no leaks or ruptures due to SCC occur during testing, implement a written hydrostatic retest program with a technically justifiable interval.

B. SCC Hydrostatic Test Leak or Rupture - if a leak or rupture due to SCC occurs, one of the following options shall be used to address long-term mitigation of SCC.

- Evaluate repair methods for SCC following the guidelines and recommendations contained in Procedure PS-03-01-254: "Threat Prevention and Repair Chart".
- A written hydrostatic retest program shall be implemented for the subject pipeline segment.
- The hydrostatic retest interval shall be carefully considered and shall be technically justifiable.

7.5 Engineering Critical Assessment

7.5.1 An Engineering Critical Assessment is a formal evaluation of the risks of SCC and additional mitigation methods. It is a written document that provides a technically defensible plan that demonstrates satisfactory pipeline safety performance. The assessment shall consider the defect growth mechanisms of the SCC process.

7.6 Periodic Reassessment

7.6.1 Periodic reassessment is the process in which given segments of a pipeline are re-investigated at an appropriate time interval.

7.6.2 The number of additional investigations that would be required on a given pipeline segment and the reassessment intervals shall be determined based on information such as:

- The extent and severity of the SCC detected during the original investigation.

- The estimated rate of propagation of the crack clusters and remaining life of the pipe containing the clusters.

- The total length of the pipe segment.

- The total length of potentially susceptible pipe within the segment.

- The potential consequences of a failure within a given segment.

7.6.3 Consideration should also be given to whether the criteria used for excavation site selection in the initial assessment are appropriate for the reassessment.

7.7 Effectiveness of SCCDA

7.7.1 Methods for evaluating the effectiveness of the SCCDA approach shall be established.

7.7.2 SCCDA is a continuous improvement process. Successive applications of the SCCDA process should better enable identification of segments and locations on the system where significant SCC is likely to occur.

7.7.3 Methods used to assess SCCDA effectiveness include, but are not limited to, the following:

- Comparison of results for selected excavation sites with results for control excavations.

- Comparison of results of SCCDA for selected segments with results of ILI using crack detection tools.

- Statistical analysis of data from SCCDA excavations to identify statistically significant factors associated with the occurrence and/or severity of cracking.
- Successive applications of SCCDA to a pipeline segment.

- Assessment of SCC predictive models with respect to reliability of predicting locations and severity of SCC.

7.7.4 Performance Measures

A. As a minimum, the following performance measures shall be documented for the SCC threat in order to establish the effectiveness of the program and for confirmation of the inspection intervals.

- Number of in-service leaks/failures due to SCC
- Number of repair or replacements due to SCC
- Number of hydrostatic test failures due to SCC

8.0 OTHER DATA:

8.1 During the direct examination and mitigation activities other data may be discovered that may be pertinent to other threats or potential threats. This data should be used where appropriate for performing risk assessments for other threats.

8.2 Review for potentially active SCC

8.2.1 On a quarterly basis, the External Corrosion Program Manager shall review data from pipe inspection digs located on pipeline segments potentially susceptible to SCC.

- Pipeline segments susceptible to SCC are identified in the Risk Model output.
- Dig location data shall be reviewed for both covered and non-covered pipeline segments.
- Purpose of the data review is to determine whether the potential for SCC exists at any dig location.

8.2.2 The External Corrosion Program Manager shall notify the Manager, Pipeline Integrity of the results of the review.

- Identify the data reviewed (general description).

- If potential for SCC is suspected.
- Notification is via e-mail with copies to the Direct Assessment Manager for information and to the Supervisor, Data Management for recordkeeping.

8.2.3 If a potential for SCC exists at any dig location, the Manager, Pipeline Integrity shall develop a plan for addressing the issue. The plan shall include:

- Identification of dig locations
- Assessment requirements

8.2.4 The Manager, Pipeline Integrity shall document the plan and transmit it to the Direct Assessment Manager for action and to the Supervisor, Data Management for recordkeeping.

8.2.5 The Direct Assessment Manager shall develop and implement a schedule for assessing the dig location. The assessment shall follow the requirements of this procedure. The schedule shall be transmitted to the Supervisor, Data Management for recordkeeping.

9.0 SCCDA RECORDS:

9.1 This section discusses the documentation of the data and information collected and decisions made during the SCCDA process.

9.2 Pre-Assessment Documentation

9.2.1 All pre-assessment step actions shall be recorded. This may include, but is not limited to:

- Documentation on the analysis used to select susceptible pipeline segments for SCCDA.
- Data elements collected for the pipeline segments to be evaluated, in accordance with Table 1.
- Methods and procedure used to integrate data, prioritize segments, and select dig sites.

9.3 Indirect Inspection Documentation

9.3.1 All indirect inspection step actions shall be recorded. This may include, but is not limited to:

- Documentation on the analysis used to identify data needs and select specific indirect inspection techniques.

- Data elements collected for the pipeline segments to be evaluated.

- Methods and procedure used to integrate data, prioritize segments, and select dig sites.

9.4 Direct Examination Documentation

9.4.1 All direct examination actions shall be recorded. This may include, but is not limited to:

- Data collected for field site verification
- Data collected prior to coating removal
- Data collected after coating removal
- Results of analysis of cracking, if found
- Results of assessment of severity of cracking, if found

9.5 Post Assessment Documentation

9.5.1 All post assessment actions shall be recorded. This may include, but is not limited to:

- Whether mitigation was required, the type of mitigation selected, and the justification for the selection.

- Criteria used to select reassessment intervals and the intervals selected.

- Scheduled activities, if any.

- Results of magnetic particle and dye penetrant inspections, and pressure tests.

10.0 REFERENCES:

10.1 Regulatory:

- Department of Transportation 49 CFR Part 192

10.2 Industry Practices:

- ASME B31.8
- ASME B31.8S
- NACE Proposed Recommended Practice for Stress Corrosion Cracking Direct Assessment Methodology (Draft dated 7/7/2004)
- AASHTO T 265 (for determining soil moisture content)
- EPA 376.1 (for soil sulfide ion concentration tests)
- ASTM E 709 (for Magnetic Particle Inspection preparation and processes)
- ASTM D 1125 (for soil conductivity tests)
- ASTM D 4972 (for soil pH lab tests)
- ASTM D 512 (for soil chloride ion concentration tests)
- ASTM D 516 (for soil sulfate ion concentration tests)

10.3 Related Policies and Supporting Documents:

- PS-03-01-242, Dig Data Sheet Procedure
- PS-03-01-254, Threat Prevention and Repair Chart Procedure
- Book 2, Manual of Construction Specifications, Procedure 47, Pipeline Pressure Testing

10.4 Forms and Attachments

- Pre-Assessment Form
- Summary of Indirect Inspection Survey Results – Direct Examination Sites

11.0 DEFINITIONS:

- **Stress Corrosion Cracking:** Brittle cracking of a normally ductile material caused by the conjoint action of a corrosive environment with tensile stress.

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

- **High pH SCC:** A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3).

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

- **Intergranular Cracking:** Cracking in which the crack path is between the grains in a metal. The phenomenon is associated with high pH SCC.

- **Transgranular Cracking:** Cracking in which the crack path is through the grains of a metal. The phenomenon is associated with near-neutral pH SCC.

- **DSAW:** Double Submerged Arc Weld (DSAW) is a type of welding process used in fabrication of pipe.

- **ERW:** Electric Resistance Weld (ERW) is a method of welding the long seam of a pipe during manufacture in which the two sides of the seam are first heated by the application of an electric current and then forced together to form a bond.

- **Magnetic Particle Inspection (MPI):** A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field. In its simplest form a dry magnetic powder is dusted on the pipe in the presence of a magnetic field.

- **Black on White MPI (BWMPI):** An MPI technique that uses a suspension of black magnetic iron particles that are applied on a white painted pipeline surface in the presence of a magnetic field.

- **Wet Fluorescent MPI (WFMPI):** An MPI technique that uses a suspension of magnetic particles that are fluorescent and visible with an ultraviolet light.

- **Wet Visual MPI (WVMPI):** An MPI technique that uses a suspension of magnetic particles that are visual with natural light.

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

- **Coating System:** The complete number and types of coats applied to a substrate in a predetermined order. When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.

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

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

- **B31G:** A method (from the ASME standard) of calculating the pressure-carrying capacity of a corroded pipe.

- **RSTRENG:** A computer program designed to calculate the pressure-carrying capacity of a corroded pipe.

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

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

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

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

- **MAOP:** Maximum Allowable Operating Pressure (MAOP) is the maximum internal pressure permitted during the operation of a pipeline.

- **Mechanical Damage:** Anomalies in pipe, including dents, gouges, scratches, and metal loss, caused by the application of an external force.

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

- **Microbiologically Influenced Corrosion (MIC):** A form of corrosion that results from certain microbes and nutrients in the soil.

- **pH:** The negative logarithm of the hydrogen ion activity written as:

  $pH = -\log_{10}(a_H^+)$

  where a_H^+ = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion activity coefficient.

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

1.0 PURPOSE

This procedure provides the form used to record information whenever pipe is excavated to perform an integrity assessment.

2.0 PROCEDURE

The Dig Data Sheet provided in this procedure is a Excel spreadsheet to be used to record various data whenever a segment of pipeline is exposed during the performance of integrity assessments (in-line inspections, pressure tests, and direct assessments for external corrosion, internal corrosion, and stress corrosion cracking).

The spreadsheet is available in Section 3.4 of this procedure. It is expected that field notes will be transferred to the electronic version and the electronic version will be the permanent record to be filed in the integrity management database.

The spreadsheet is divided into 14 sections. The first eight sections are for recording "common data" that is usable for all assessment methods. Sections 9.0 through 14.0 are for specific assessment methods. If <u>NO</u> coating damage is found during pipe surface inspection activities, only sections requiring soil chemistry shall be completed (Sections 1.0, 2.0, 3.0, 4.0, 5.0, 6.0, and 7.0).

The user shall fill in the spreadsheet (it's self-explanatory) and indicate "Not Applicable" or "NA" for sections or parts of sections that are not applicable for the assessment method being conducted.

Upon completion, and after conversion to the electronic version of the spreadsheet, the Dig Data Sheet shall be transmitted to the Data Management Specialist for entry into the Asset Inventory Database. The Data Management group will notify the Integrity Management group the Database has been updated and the information is available for use.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S: Managing System Integrity of Gas Pipelines
- NACE Recommended Practice RP0502-2002: External Corrosion Direct Assessment.
- NACE Draft Recommended Practice for Internal Corrosion Direct Assessment (Draft dated 3-16-2004)
- NACE Draft Recommended Practice for Stress Corrosion Cracking Direct Assessment (Draft dated 7- 7-2004)

3.3 Related Procedures/Supporting Documents

- PS-03-01-232, External Corrosion Direct Assessment Procedure
- PS-03-01-238, Dry Gas - Internal Corrosion Direct Assessment Procedure
- PS-03-01-240, Stress Corrosion Cracking Direct Assessment Procedure
- PS-03-01-244, In-Line Inspection and Analysis Procedure
- Book 2, Manual of Construction Specifications, Procedure No. 47, Pipeline Pressure Testing

3.4 Forms and Attachments

- Dig Data Sheet

4.0 DEFINITIONS

- None

1.0 PURPOSE:

This procedure describes the process for preparing for and running an In-Line Inspection (ILI) tool, assessment of tool accuracy, analysis of the inspection data, verification of the ILI Final Report, development of a plan to address features requiring investigation, and final documentation.

2.0 PROCEDURE:

2.1 The Company shall consider at least two types of internal inspection tools for integrity assessment for the Integrity Management Program from the following list:

- Caliper Tools for detecting changes in ovality due to construction flaws, soil movement and third party damage
- Metal Loss Tools for determining pipe wall anomalies.
- Crack Detection Tools for detecting cracks and crack-like features

NOTE:

Dents are defined as depressions in the surface of the pipe that have a minimum depth dimension of 2% of pipe curvature for pipe greater than 12 inches in diameter. For pipe less than 12 inches in diameter, the minimum depth dimension is 0.250 inches.

Caliper tools shall be the guiding factor to define dents. Caliper tools identify all dents that are equal to or exceed 2% of the curvature of the pipe (0.250-inches in depth for a pipeline diameter less than NPS 12). Caliper tool data shall be integrated with the Metal Loss tool data to define dents with associated metal loss that may be defined as Immediate Repair Conditions.

Criteria for identifying and reporting dents are discussed in Section 2.7.2 of this procedure.

2.1.1 The type of tool or tools shall be selected by the Company's qualified personnel as defined in Procedure PS-03-01-272 "IMP Personnel Qualification Requirements" and shall be selected according to the conditions specified in Procedure PS-03-01-252: "Schedule of Repair Requirements". The suspected conditions shall be defined by the results from previous internal inspection runs, if any, analysis of pipeline data and information, and risk factors specific to the pipeline segment.

A. If information analysis of pipeline data (risk assessment) indicates a high risk factor for a covered pipeline segment to be internally inspected that contains low frequency electric resistance welded pipe (ERW) or lap welded pipe with a history of longitudinal seam failure, an appropriate tool should be considered that is capable of detecting seam corrosion and deformation anomalies.

2.1.2 Refer to ASME B31.8S Section 6.2: Pipeline In-line Inspection, and section 7.2: Responses to Pipeline In-line Inspections, for specific guidelines for gas pipelines. The following shall be considered when selecting the appropriate in-line inspection tool:

- Detection Sensitivity - minimum defect size specified for the ILI tool should be smaller than the size of the defect sought to be detected.
- Classification - differentiation between types of anomalies.
- Sizing Accuracy - enables prioritization.
- Location Accuracy - enables locating anomalies by excavation.
- Requirements for Defect Assessment - results of in-line inspection have to be adequate for the defect assessment program.

2.1.3 The general reliability of the ILI method shall be assessed by looking at the following:

- Confidence level of the ILI method (for example, probability of detecting, classifying and sizing the anomalies).
- History of the ILI method/tool.
- Success rate/failed surveys.
- Ability of the tool to inspect the full length and full circumference of the pipe section.
- Ability to indicate the presence of multiple cause anomalies.

2.1.4 The basis for tool selection shall be documented.

2.2 Preparation for Running an ILI Tool:

2.2.1 Perform pre-assessment to include:

A. Review pipeline inspection and rehabilitation history.

B. Coordinate trap modifications including design and drawings.

C. Select the ILI vendor and complete the "Pipeline Pigging Questionnaire" form in Procedure PS-03-01-246. The Pipeline Pigging Questionnaire is the method used by the Company to provide the ILI vendor information on the significant parameters and characteristics of the pipeline section to be inspected. Some of the more important issues that shall be considered are:

- Pipe characteristics such as steel grade, type of welds, length, diameter, wall thickness, elevation profiles, etc.
- Launchers and receivers should be reviewed for suitability since ILI tools vary in overall length, complexity, geometry, and maneuverability.
- Pipe cleanliness can significantly affect data collection.
- The presence of fluid in the pipeline can affect the possible choice of ILI tool technologies.
- Flow rate of the gas will influence the speed of the ILI tool inspection. If speeds are outside of the normal ranges, resolution can be compromised. Total time of inspection is dictated by inspection speed, but is limited by the total capacity of batteries and data storage available on the tool.
- High temperatures can affect tool operation quality and shall be considered.
- Pipeline operating pressure.
- Reduction of gas flow and speed reduction capability on the ILI tool may be a consideration in higher velocity pipelines. Conversely, the availability of supplementary gas where the flow rate is too low shall also be considered.

D. Provide the ILI vendor with Procedure PS-03-01-248: "ILI Vendor Performance Specification".

E. Coordinate Aboveground Marker (AGM) site locations and respective surveys.

F. Determine if additional pig runs (cleaning, sizing, geometry, etc.) are required.

G. Coordinate with Systems Management/Operations Control, Region Director, Region Pipeline Specialist, Area Teams, ILI vendor, and contract inspection to schedule the in-line inspection.

H. Investigate potential obstructions and intrusions into the pipeline that could cause damage to the inspection tools utilizing the vendor's tool specifications for any specific safe tool passage requirements. These may include, but are not limited to:

- Inhibitor injection nozzles or pitot tubes
- Corrosion coupons
- Pig signals
- Non-full-opening valves (e.g., gate or check valves)
- Barred tees in the wrong location
- Regulators
- Nozzles, punch tees or taps that protrude into the line
- Repairs that protrude into the line
- Previous repairs that may restrict the passage of a pig, such as a repair sleeve that encapsulated a dent
- Ultrasonic or other meters
- Pipe diameter changes
- Bend radius shorter than tool specifications

I. Review past pipeline repair and/or maintenance reports for any indication that would infer or confirm that a restriction has been placed into the pipeline, which would not allow passage of an internal inspection tool. Take into consideration the ILI vendor's ILI tool specifications when performing this review.

J. Contact and interview operations and maintenance personnel concerning past repair methods, changes or modifications to the pipeline that may have resulted in a restriction that would not allow passage of internal inspection tools.

K. Contact and interview operations personnel concerning the physical condition of pigs, spheres or balls that have previously been run in the pipeline during cleaning or other types of maintenance activities. Damaged or cut pigs or spheres or abnormal wear could indicate potential restrictions or obstructions in the pipeline. This interview should also provide information on the cleanliness of the pipeline and information on any debris as a result of pigging operations.

L. If potential restrictions or intrusions are located during the investigation, prepare a job plan to either temporarily or permanently remove the restrictions prior to running internal inspection tools. As an option to removing restrictions, facilities may need to be installed or operated to allow pigs to bypass the obstruction, as in the case of a regulator station. Any potential restriction or intrusion identified above shall be specifically listed on the pigging questionnaire and resubmitted to the ILI vendor.

M. Review the pipeline condition with the Region Engineer and/or Operations Manager and ILI vendor to determine if cleaning pig activities are necessary. Schedule and perform cleaning pig activities as required and ensure liquid/solid sampling is performed in accordance with PS-03-02-292: “Obtaining Testing Fluid & Solid Sampling”.

N. Contact the Region Engineer and/or Operations Manager and Area Environmental Specialist if cleaning pig activities are necessary. Review results with Region Engineer and/or Operations Manager and ILI vendor to determine adequacy of cleaning.

O. Review the “Internal Corrosion Control Program” procedure to determine sampling requirements relating to running any cleaning pig.

P. Verify with the Service Area Leader after conducting all of the needed contacts, interviews and investigations that the pipeline is set up properly to allow safe passage of the internal inspection tool.

Q. The pre-assessment should provide details on valve operation, loading, running and retrieving the internal inspection tools.

R. Coordinate Aboveground Marker (AGM) site locations and respective surveys with the ILI vendor and consider the following:

- Alignment sheets
- Multiple ILI vendors
- Combination of one or more tools to detect specific conditions (e.g., anomalies, metal loss, cracks, features, etc.)
- Direction of tool runs in relation to station/line numbering
- Collection of GPS data on AGM locations

2.2.2. Requirements for AGMs:

1. AGMs shall be selected prior to the ILI run and marked with a Carsonite pipeline marker or sign. A permanent concrete marker should be installed at the AGM locations selected to allow these AGM locations to be used for all future ILI runs. The concrete markers should be a minimum of 10 to 12 inches in diameter and set 2 foot deep with the top being at ground level.

2. GPS coordinates shall be taken of the AGM location for future reference. This list should also be maintained for future ILI runs. A hand-held GPS unit is acceptable for taking the reading.

3. Recommended placement:

   - Spacing should not exceed 1 mile between AGMs

   - An AGM should be located at the upstream station at the start of the HCA or Identified Site OR the same point at the start of a series of HCAs whose total length is less than 1 mile whenever possible.

   - In farmland the AGMs should not be placed in plowed ground, but should be placed in fence rows, ditch banks, etc.

4. Pipeline features may be substituted for AGMs, as follows:

   - Taps 2 inches and larger with aboveground facilities
   - Main line valves
   - Cased road crossing with aboveground vents
   - Blowdowns 2 inches and larger

- Major interconnects 2 inches and larger with aboveground facilities

5. Chain in and set AGMs at proper locations based upon changes in pipe material (grade, diameter, wall thickness), points of entry and exit of HCAs, identifiable GIS/mapping internal data/landmarks, ILI vendor recommendations or other pertinent information.

2.2.3. Select and schedule sizing and/or caliper inspection tools as required. If running a caliper tool, consider future coordination/alignment with metal loss and/or crack detection tools. For the detection of dents with metal loss or cracking, refer to Procedure PS-03-01-252: "Schedule of Repair Requirements" for any additional requirements. Evaluate the results of sizing and/or caliper tool runs including tool wear, the preliminary and final data report, cleanliness, etc. Utilize this information to resolve any pipeline potential obstructions before running additional ILI tools.

1. If a sizing and/or caliper inspection tool is run, provide data to vendor for review and verification of suitable pipe bore and bend radius.

2. Identify High Consequence Areas for a given line segment and, if required, provide the ILI vendor specified analysis windows.

2.2.4 Schedule and then run the appropriate ILI tool.

2.3 Running an ILI Tool:

2.3.1 Pre-run Tool Inspection

A. Inspect tool for damage prior to loading tool in scraper trap (launcher).

B. If tool damage is present:

1. Prepare a written description of the damage and also document with photographs.

2. Notify Project Management, Pipeline Integrity, and the vendor, who will jointly determine whether repairs are required prior to loading the tool.

C. Verify the tool is properly cleaned prior to loading to avoid cross-contamination.

2.3.2 Utilizing the pre-assessment, complete the following during the ILI tool run.

A. Track tool through the AGMs and aboveground valve locations.

B. Perform a preliminary evaluation of the results of the ILI tool run to ensure the tool performed within specification. Rerun the ILI tool if the results are not acceptable, as determined by the Company's ILI Project Coordinator.

C. Retain the ILI run documentation (benchmarking spreadsheets, AGM sheets, and tracking reports) and place in the ILI project job folder.

D. Document the date of ILI device removal from the trap.

2.3.3 Post-run Tool Inspection

A. Clean the tool after the run and inspect for damage.

B. Properly dispose of cleaning solution.

C. If tool damage is present:

1. Prepare a written description of the damage and also document with photographs.

2. Notify Project Management, Pipeline Integrity, and the vendor, who will jointly determine whether repairs are required.

2.3.4 The ILI vendor is required to issue a Preliminary Report within 14 calendar days of completion of the ILI tool run to the Company's Pipeline Integrity Engineer. The Preliminary Report identifies the following conditions based on the ILI tool's capabilities:

A. Metal loss equal to or greater than 70% of nominal wall thickness, regardless of dimensions.

B. A significant anomaly that in the judgment of the data evaluator requires immediate action.

C. Cracks, to the extent preliminary indications are within established TFI tool reporting procedures

2.3.5 If any of the conditions outlined above are identified in the Preliminary Report, the Company shall excavate and remediate in accordance with Procedure PS-03-01-252: "Schedule of Repair Requirements" and provide any feature information back to the ILI vendor for data validation and calibration.

A. If feature information indicates that anomalies are more severe than the Preliminary Report suggested, analyze the anomaly based on required tool recalibration and take appropriate actions in accordance with Procedure PS-03-01-252: "Schedule of Repair Requirements".

B. Determine with the ILI vendor if a rerun of the pipeline segment is required to assure accurate ILI analysis. If a tool rerun is determined to be necessary, the ILI vendor will recalibrate and rerun the ILI tool and then provide the Company with a revised Preliminary Report.

2.4 Assessment of ILI Tool Accuracy:

2.4.1 Excavate a representative sample of each type of anomalies to verify anomaly locations and accuracy of vendor data. This may be performed during normal dig schedule.

2.4.2 Field feature examination details shall be provided to the ILI vendor, if necessary.

2.4.3 Based on the actual depths found versus vendor log information, the final ILI log will be re-graded if the depths and/or lengths of the features are incorrect by more than 15 percent to 20 percent of the time. This is the minimum accuracy expected. If a vendor specifies a more stringent accuracy, that specification shall be met or the final log will be re-graded.

2.5 Analysis of Inspection Data:

2.5.1 The Company shall provide the ILI vendor the interaction criterion and feature assessment criterion to be used in the assessment of the metal loss features. The following will be employed by the Company:

A. The interaction criterion employed by the Company is that corrosion pits are considered to interact when they are located within 3t (t = nominal wall thickness) of one another (for example, for features located in pipe with a nominal wall thickness of 0.250 inches, corrosion pits are considered to interact when they are located within 0.75 inches of each other). If features are within 3t of each other, the sum of the features is considered a cluster.

B. Corrosion Assessment:

1. The severity of corrosion features identified by the in-line inspection shall be assessed using ASME B31G, RSTRENG or other approved engineering methods used for calculating the remaining strength of corroded pipe for determination of the repair criteria.

2. The Company will determine with the ILI vendor, the vendor's capabilities and the scope of the detailed analysis of the corrosion assessment to be delivered to the Company in the ILI Final Report.

2.5.2 Ensure the vendor's ILI Final Report contains at a minimum, the main features requested by the Company.

A. All detected metal loss defects as predicted by analysis process, location, discrimination between internal and external defects, and discrimination between metal loss and manufacturing faults.

B. Cracks located in longitudinal ERW weld seams (TFI tool specific).

C. The location of dents with a depth equal to or greater than 2% of the pipeline's diameter (0.250-inches in depth for a pipeline diameter less than NPS 12) , gouges, and scratches and the presence of any associated metal loss.

D. The location of all girth welds.

E. The location of eccentric or shorted casings and any associated metal loss.

F. The location of any foreign metal objects in close proximity to the pipe.

G. A listing of all nominal wall thickness changes to include grade, thickness, and diameter with corresponding location, if applicable.

H. A listing of all repair patches and sleeves, including but not limited to composite sleeves, if bands are present.

I. A listing of all "hard" references and aboveground marker devices which have been used as location reference points.

2.6 Verifying the Data Collected:

2.6.1 An ILI report will not be considered a Final Report until the data is verified utilizing Company supporting documentation. The following will be verified by qualified personnel to ensure that the ILI vendor is providing accurate data:

A. Correct outside pipe diameter.

B. Correct nominal pipe wall thickness.

C. Correct pipe grade.

D. 100% SMYS calculation has been performed correctly.

E. Anomaly percent depth calculation has been performed correctly.

F. Review of all wrinkle bend indications for correlation with alignment sheets.

G. Review all pipeline appurtenances with alignment sheets.

H. Predicted failure or rupture pressure calculations have been performed correctly.

I. Offsets have been entered correctly.

J. AGMs have been entered correctly and the benchmarks were set properly.

K. Slippage has been accounted for and calculated correctly.

L. Distances to the upstream and downstream girth welds add up to the expected joint length.

M. Odometer starts at the beginning of the run and counts up in a predictable manner to the end of the run.

N. Calculated station numbering from both the upstream reference (AGM) and the downstream reference (AGM) starts at the beginning of the run and counts up in a predictable manner to the end of the run.

O. Sort the report based on the item description bringing similar features together. Scan these groupings for anything unusual.

P. Accept the report as the Final Report or reject the report. Return rejected report to vendor for correction and verify the re-submitted reports per the requirements of this section of this procedure.

2.7 ILI Final Report Evaluation:

2.7.1 Analyze the ILI Final Report for any metal loss indications and categorize by response time as indicated in Procedure PS-03-01-252: “Schedule of Repair Requirements”.

A. Once the ILI Final Report has been accepted by the Company, a list of predicted failure pressure values shall be generated:

1. If a predicted failure pressure is equal to or less than 1.1 x MAOP, a 20% reduction in operating pressure and investigation

will be initiated in accordance with the Procedure PS-03-01-252: "Schedule of Repair Requirements" within five days of discovery.

2. For predicted failure pressure values greater than 1.1 x MAOP, an investigation shall be initiated that shall include a discrete point pressure analysis and remediation shall be performed in accordance with Procedure PS-03-01-252: "Schedule of Repair Requirements".

2.7.2 Analyze the ILI Final Report for all geometry indications and categorize by response time as indicated in Procedure PS-03-01-252: "Schedule of Repair Requirements".

A. Once the ILI Final Report has been accepted by the Company, a list of geometry indications will be generated and categorized by the following:

1. Dent and/or gouge that has an indication of metal loss, cracking or stress riser (may require additional analysis of metal loss and/or cracking indication ILI reports).

2. Smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50-inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

3. A dent with a depth greater than 2% of the pipeline's diameter (0.250-inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

4. A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50-inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1⁄3 of the pipe).

5. A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50-inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and

engineering analysis of the dent demonstrates critical strain levels are not exceeded.

6. A dent with a depth greater than 2% of the pipeline's diameter (0.250-inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld demonstrates critical strain levels are not exceeded. The analysis shall consider weld properties.

2.7.3 Analyze the TFI report for any crack or crack-like indications and categorize by response time as indicated in Procedure PS-03-01-252: "Schedule of Repair Requirements".

A. Once the ILI Final Report has been accepted by the Company, a list of crack or crack-like indications shall be generated and categorized by the following:

1. Stress riser associated with a dent (may require additional analysis of geometry indications).

2. Axially aligned cracks in area of welds.

3. Longitudinal cracks in area of seams.

4. General cracking (Stress Corrosion Cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks).

2.8 Development of a Plan for Features Requiring Investigations:

2.8.1 Qualified personnel shall analyze the ILI Final Report and identify the features to be evaluated.

2.8.2 The Company's Pipeline Integrity Engineer - In-Line Inspection (PIE-ILI) shall prepare a detailed Dig List comprised of features to be investigated. When preparing the Dig List, the PIE-ILI shall integrate the results of the in-line inspection with data on encroachments and foreign line crossings in the same pipeline segment to define locations of potential third party damage.

2.8.3 The Company's PIE-ILI shall coordinate the production of dig sheets for field examination of the features listed in the Dig List.

2.8.4 After the features have been identified for evaluation and a Dig List prepared, as defined by Procedure PS-03-01-252: "Schedule of Repair Requirements", this list will be provided to Project Services.

2.8.5 During direct examination, when corrosion is found that could adversely affect the integrity of the pipeline, then all pipeline segments, both covered and non-covered, with similar coating type and environmental characteristics shall be inspected and remediated as necessary. Perform the following actions:

A. Notify by e-mail the Senior Pipeline Integrity Engineer, the Internal Corrosion Program Manager (if internal corrosion is present), the External Corrosion Program Manager (if external corrosion is present), and the Supervisor, Data Management (for recordkeeping).

B. The Senior Pipeline Integrity Engineer identifies all pipeline segments that have similar coating type and is located in similar environmental characteristics.

C. The list of similar pipeline is transmitted to the Internal and External Corrosion Program Managers, as appropriate, for action and to the Supervisor, Data Management for recordkeeping.

D. The Internal and External Corrosion Program Managers, as appropriate, develop action plans for inspection, evaluation, monitoring and remediation if needed. The action plans are transmitted to the Supervisor, Data Management for recordkeeping, the Manager, Pipeline Integrity for information, and the Senior Pipeline Integrity Engineer for updating the annual and long-term assessment plans.

2.9 Documentation:

2.9.1 The ILI vendor is required to submit reports to the Company's ILI Project Coordinator within the time lines defined in Procedure PS-03-01-252: "Schedule of Repair Requirements".

2.9.2 The vendor-supplied ILI Final Report shall be kept on file for the life of the pipeline. All field inspection results and reports will be placed in a job file and sent to the Data Management Specialist for posting and to be stored for the life of the pipeline. The following documents will be placed in the job file as applicable:

- IO/Work Order
- Pre-Assessment
- ILI Vendor Preliminary Report
- ILI Final Report
- ILI Vendor Personnel Qualification Documentation (if requested)
- Dig List Report
- Dig Sheets
- Dig Data Sheets
- ILI Summary and Dig Sheet Request or Report
- ASME B31G or RSTRENG calculations or other approved engineering method used for calculating the remaining strength of corroded pipe (if needed)
- Feature Rubbings (If needed)
- Welding Procedures (if needed)
- Welder Qualification Records (if needed)
- Daily Safety Meeting Reports
- One-Call Information
- Mill Certification (MTRs) on new line pipe or sleeve materials (if needed)
- Hydrostatic Test Reports on new line pipe installed from cut-outs (if needed)
- Post Assessment
- Follow Up (as needed)
- Re-Assessment

3.0 REFERENCES:

3.1 Regulatory:

- 49 CFR Part 192

3.2 Industry Practices:

- ASME B31.8S-2001

- ASME B31G
- RSTRENG

3.3 Related Procedures/Supporting Documents:

- PS-03-01-222, Baseline Assessment Inspection & Remediation Schedule Procedure
- PS-03-01-246, Pipeline Pigging Questionnaire Procedure
- PS-03-01-248, ILI Vendor Performance Specification Procedure
- PS-03-01-252, Schedule of Repair Requirements Procedure
- PS-03-01-272, IMP Personnel Qualification Requirements Procedure
- PS-03-02-292, Obtaining Testing Fluid & Solid Samples Procedure

3.4 Forms and Attachments:

- None

4.0 DEFINITIONS:

- None

1.0 PURPOSE

This procedure establishes the processes for addressing anomalous conditions discovered through Integrity Assessment Inspection and Pipeline Risk Assessment.

2.0 PROCEDURE

2.1 General

The Company shall evaluate all anomalous conditions and remediate according to the established schedule developed in accordance with Procedure PS-03-01-252: “Schedule of Repair Requirements”.

The Company shall demonstrate that the remediation of an identified anomalous condition ensures that it is removed as a threat to the long-term integrity of the pipeline. This will typically be self-evident from the type of repair implemented.

The Company shall ensure a temporary reduction in operating pressure does not exceed 365 days without conducting a technical justification that assures the continued pressure reduction will not jeopardize the integrity of the pipeline.

The Company shall make repairs in accordance with Procedure PS-03-01-254: “Threat Prevention and Repair Chart” and applicable Company operation and maintenance pipeline repair procedures.

2.2 Discovery of Condition

Discovery of a condition occurs when adequate information about the condition is collected to determine that the condition presents a potential threat to the integrity of the pipeline. The date the condition is discovered shall be recorded.

The Company shall use Qualified Personnel to obtain sufficient information about a condition to determine whether it has the potential to threaten the integrity of the pipeline immediately following, but no later than 180 days after the integrity assessment inspection, unless the 180 day period can be proven to be impracticable.

If the Company cannot make the necessary determination within the 180-day period, the Company will notify the Office of Pipeline Safety (OPS) of the reasons for the delay and the expected time for obtaining the information. Notification shall be made in accordance with Section 2.6 “Inability to Meet Schedule or Reduce Pressure” of this procedure.

2.3 Requirements for Scheduling Remediation

Repair conditions, as defined in the regulations, shall be categorized into one of the following three categories and shall be evaluated and remediated within the specified time identified in Procedure PS-03-01-252 “Schedule of Repair Requirements”.

- **“Immediate”** Repair Condition - Indication shows that the defect is at failure point.
- **“Scheduled”** Repair Condition - Indication shows the defect to be significant but not at the point of failure. Remediation will be performed based on ASME B-31G calculations or RSTRENG and applied corrosion growth rate calculations.
- **“Monitored”** Repair Condition - Indication shows the defect will not fail before the next inspection or reassessment.

The Company’s evaluation and remediation schedule shall follow ASME B31.8S, Section 7: “Responses To Integrity Assessments And Mitigation (Repair And Prevention)”, in providing for “Immediate” repair conditions.

When it is determined that an “Immediate” repair condition exists, the Company shall implement, if required, safety-related condition reporting requirements as specified in Book 1, Operating and Maintenance Manual, Procedure 108: “Identifying and Reporting Safety Related Conditions”, and shall also consider either a temporary reduction in operating pressure or a pipeline shutdown until repairs are completed. Requirements for temporary reductions in operating pressure are discussed later in this procedure.

2.4 Schedule for Evaluation and Remediation

After each integrity assessment is completed, refer to Procedure PS-03-01-252: “Schedule of Repair Requirements” and perform the following:

- Evaluate the assessment results within 14 days of the acceptance of the final report and determine which defects are an “Immediate” condition.

- Evaluate the assessment results and determine which defects are ”Scheduled” and which are “Monitored” conditions within 30 days.

Populate and/or update the Remediation Schedule (refer to Procedure PS-03-01-222: “Baseline Assessment Plan Spreadsheet”) from the results of each evaluated assessment. Prioritize the evaluation and remediation of HCA segments from highest to lowest risk utilizing Procedure PS-03-01-216: “Threat Identification and Risk Assessment”.

Complete remediation of a condition according to Procedure PS-03-01-222: “Baseline Assessment Plan Spreadsheet” and Procedure PS-03-01-254: “Threat Prevention and Repair Chart”.

If the remediation schedule cannot be met for any condition, justify and document the reasons why the Company cannot meet the schedule and that the changed schedule will not jeopardize public safety.

If the remediation schedule cannot be met for any reason, a temporary reduction in operating pressure or other mitigative action shall be implemented until the remediation is completed. The temporary pressure reduction shall meet the following requirements:

- Determine the amount of the temporary pressure reduction in accordance with ASME B31G or RSTRENG, or

- Reduce the operating pressure to 80% of the pressure level at the time the condition was discovered.

The OPS shall be notified in the event the Company cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure. The reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety shall be provided in the notification.

2.5 Temporary Operating Pressure Reduction

When an “Immediate” repair condition exists, temporarily reduce the operating pressure of the pipeline in accordance with the following:

- Determine the amount of the temporary pressure reduction in accordance with ASME B31G or RSTRENG, or
- Reduce the operating pressure to 80% of the level at the time the condition was discovered.

The operating pressure at the time of discovery shall be documented, as well as the pressure reduction to be taken and the method for determining the pressure reduction. The five data points are reiterated below:

- Date of discovery
- Pipeline operating pressure at time of discovery
- Amount of pressure reduction
- Pressure reduction calculation method
- Date of repair

The reduction in operating pressure cannot exceed 365 days unless a technical justification is performed and documented that the continued pressure restriction will not jeopardize the integrity of the pipeline.

The Company shall notify the OPS when the duration of the reduction in operating pressure exceeds 365 days. The Company will also notify a State or local pipeline safety authority where the OPS has an interstate agent agreement or an intrastate covered pipeline segment is regulated by the State. The reasons why the extended pressure reduction will not jeopardize the integrity of the pipeline shall be provided in the notification.

2.6 Inability to Meet Schedule or Reduce Pressure

Within 180 days of an integrity assessment, the Company shall collect sufficient information regarding the apparent pipeline condition to determine the appropriate remediation (repair) schedule. If the 180-day determination requirement cannot be met, OPS or the authorized State agency shall be notified in accordance with Procedure PS-03-01-264: "IMP Communication Plan".

Notification includes at a minimum:

- Description of defects or repairs required.
- Justification for delay, including basis explaining why the delay will not jeopardize health, safety or environment.
- Explanation of why pressure cannot be reduced.
- Repair schedule.
- Other mitigative actions planned.

2.7 Documentation

The technical justification for exceeding the 365 day temporary pressure reduction limit shall be documented.

The reasons the repair schedule cannot be met shall be documented.

The reasons the determination of condition classification (Immediate, Scheduled, and Monitored) cannot be accomplished in the allowed 180 day time frame shall be documented.

All temporary pressure reductions, remediation schedules and schedule changes, and remediation actions shall be documented.

Any mitigative actions taken as a result of inability to meet the remediation schedule until the remediation is completed shall be documented.

All documentation generated as a result of this procedure shall be recorded in the Company's Pipeline Integrity filing system.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S: Managing System Integrity of Gas Pipelines
- ASME B31.8: Gas Transmission Distribution and Piping Systems
- ASME B31G: Manual for Determining the Remaining Strength of Corroded Pipelines
- RSTRENG

3.3 Related Procedures/Supporting Documents

- PS-03-01-216, Threat Identification and Risk Assessment Procedure
- PS-03-01-222, Baseline Assessment Plan Spreadsheet Procedure
- PS-03-01-252, Schedule of Repair Requirements Procedure
- PS-03-01-254, Threat Prevention & Repair Chart Procedure
- PS-03-01-264, IMP Communication Plan Procedure
- PS-03-01-272, IMP Personnel Qualification Requirements Procedure
- PS-03-02-200, Evaluation of Remaining Strength of Corroded Pipe Procedure
- Book 1, Operating and Maintenance Manual , Procedure 108: Identifying and Reporting Safety Related Conditions

3.4 Forms and Attachments

- None

4.0 DEFINITIONS

- **ASME B31G** - Supplement to ASME Code for Pressure Piping for the purpose of providing guideline information (criterion) for measuring and determining the remaining strength of corroded pipelines.

- **HCA Affect** - The length of pipeline that intersects or tangentially touches a HCA or affects a HCA through a transport process.

- **OPS** - Office of Pipeline Safety.

1.0 PURPOSE

This procedure establishes the processes for identifying and evaluating additional measures that may be taken to enhance the prevention of pipeline failure and/or remediation of the conditions that could affect a High Consequence Area (HCA). This procedure is applicable to pipe operating at all pressure levels, including low stress pipe, and also to plastic transmission pipe.

2.0 PROCEDURE

2.1 General

The Company utilizes Procedure PS-03-01-216: "Threat Identification and Risk Assessment" and threat factors pertaining to the HCA pipeline segment to identify additional actions to enhance public safety or environmental protection.

The Company conducts a cause and effect analysis in conjunction with the annual assessment inspection schedule for each HCA segment.

- This cause and effect analysis includes the study of the threats that increase the risk in an HCA segment.
- A feasibility analysis of the available alternative solutions shall be conducted to determine the appropriate solution.
- Based on all relevant information available from the analysis, the Company determines the work to be scheduled and completed that enhances public safety and/or environmental protection.

Options that are considered by the Company to enhance public safety and/or environmental protection may include, but are not limited to:

- Installing Automatic Shut-off Valves or Remote Control Valves.
- Installing computerized monitoring and leak detection systems.
- Replacing pipe segments with pipe of heavier wall thickness.

- Providing additional training to personnel on response procedures.
- Conducting additional drills with local emergency responders.
- Implementing additional extensive inspection and maintenance programs.
- Using qualified personnel for work the Company is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.
- Participating in one-call systems in locations where covered segments are present.
- Monitoring of excavations conducted on covered pipeline segments.

2.2 Third Party Damage and Outside Force Damage

The Company shall take additional measures to prevent and minimize the consequence of a pipeline release due to third party damage or outside force damage. These measures shall be in addition to any regulatory requirements. Refer to Procedure PS-03-01-254: "Threat Prevention and Repair Chart" and the following as a guideline to consider and identify additional measures.

- Additional measures to minimize the consequences from third party damage, including vandalism, may include, but are not limited to:
  - Increasing the frequency of aerial and foot patrols
  - Participating in One-Call systems
  - Conducting extensive public education campaigns
  - Increasing marker frequency
  - Increasing cover depth
  - Adding leakage control measures

- Additional measures to minimize the consequences from outside force damage such as earth movement, floods, or an unstable suspension bridge may include, but are not limited to:

  - Increasing the frequency of aerial and foot patrols
  - Adding external structural protection
  - Reducing external stress
  - Relocating the line

Location-specific information on excavation damage (both reportable and non-reportable) that occurs in covered and non-covered segments shall be collected and maintained in the Asset Inventory Database. This shall include root cause analyses performed to support identification of targeted additional preventive and mitigative measures in high consequence areas.

The Company shall monitor excavations conducted on or near covered pipeline segments. When there is physical evidence of encroachment involving excavation that the Company did not monitor, the pipe in the area near the encroachment shall be excavated and inspected for coating damage and corrosion or an aboveground survey for external corrosion shall be conducted in accordance with the recommended practices in NACE RP0502-2002, “External Corrosion Direct Assessment” and Company Procedure PS-03-01-232: “External Corrosion Direct Assessment”.

2.3 Automatic Shut-off Valve or Remote Control Valve

To determine if an automatic shut-off valve or remote control valve is needed on a pipeline segment to protect an HCA in the event of a gas release, the Company shall consider the following factors:

- Swiftness of leak detection
- Pipe shutdown capabilities
- The type of gas being transported
- Operating pressure

- The rate of potential release
- Pipeline profile
- The potential for ignition
- Location of nearest response personnel

2.4 Coating Holidays and Other Discontinuities

Indications of coating holidays or discontinuities warranting direct examination shall be excavated and remediated in accordance with ASME B31.8S requirements. Acceptable repair methods are identified in Procedure PS-03-01-254: “Threat Prevention and Repair Chart”, which is a reproduction of Table 4 in Section 7.5 of ASME B31.8S. All remediations shall be made using the Company’s standard operations and maintenance repair procedures.

2.5 Corrosion

If corrosion is identified on a covered segment that could adversely affect the integrity of the line, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics must be evaluated and remediated, as necessary. A schedule will be developed for evaluating and remediating these segments.

2.6 Low Stress Pipelines

Natural gas transmission pipelines that are operated at less than 30 % SMYS are referred to as low stress pipelines. There are special requirements applicable to low stress pipelines.

The Company shall implement the following requirements for low stress pipe that is in a high consequence area (HCA):

- In order to enhance damage prevention against third party damage, the Company shall:
  - Use qualified personnel for work that could adversely affect the integrity of the low stress pipe. This includes marking and

locating the pipe, and direct supervision of known excavation work.

- Participate in One-Call systems.

- Either monitor excavations near the low stress pipeline, or conduct patrols in accordance with 49 CFR 192.705 of the pipeline at bi-monthly intervals. If any indications of unreported construction activities are discovered, a follow-up investigation shall be conducted to determine whether mechanical damage has occurred.

  For low stress pipe located in a Class 3 or Class 4 area, but not in an HCA, the Company shall implement the following requirements:

- The Company shall use qualified personnel for work that could adversely affect the integrity of the low stress pipe. Examples of such work include marking or locating the pipe, and direct supervision of known excavation work.

- The Company shall participate in One-Call systems.

- The Company shall perform leak surveys on a quarterly basis using semi-annual leak survey requirements for cathodically unprotected low stress pipe or for cathodically protected low stress pipe where electrical surveys are impractical.

  Procedure PS-03-01-260: “Continual Process for Evaluation and Assessment” contains the requirements for reassessment of low stress pipe.

2.7 Documentation Requirements

The Company shall document all actions considered and taken to enhance public safety and/or environmental protection as identified from the risk assessment and/or specific threat factors on each of the HCA pipeline segments. Additional preventive and mitigative (P & M) measures, i.e. measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a HCA, shall be evaluated and selected based on these identified threats. Appropriate options include those listed in Table 4 of B31.8S and Part 192.935. This analysis and evaluation shall be performed annually by the Sr. Pipeline Integrity Engineer and approved by the Manager of Pipeline Integrity. Identified and selected options shall be recorded in the spreadsheet titled “Preventive and Mitigative Measures Annual Summary”. The Preventive and Mitigative Measures Annual Summary will be distributed to Region Directors for review, scheduling and implementation.

Documentation to support enhancements to the pipeline for the protection of the public and/or environment includes:

- Records supporting decisions made concerning installation of equipment enhancements for protection of the public and/or the environment (for example, automatic shut-off valves, leak detection, replacing pipe segments, etc.)
- Records of training provided to pipeline personnel due to changes or enhancements to the pipeline
- Training plans and rosters from drills with local emergency responders
- Maintenance records

Documentation verifying the actions considered and taken by the Company to minimize third party damage shall include all documents, records, or reports supporting the measures and actions taken concerning excavation damage to a pipeline and potential damage due to encroachment.

Documentation of the implementation of preventive and mitigative measures, including those to address third party damage and outside force damage, shall be maintained in the Company’s MMS system.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S
- NACE Recommended Practice RP0502-2002: "External Corrosion Direct Assessment"

3.3 Related Procedures/Supporting Documents

- PS-03-01-216, Threat Identification and Risk Assessment Procedure
- PS-03-01-232, External Corrosion Direct Assessment Procedure
- PS-03-01-254, Threat Prevention and Repair Chart Procedure
- PS-03-01-260, Continual Process for Evaluation and Assessment Procedure

3.4 Forms and Attachments

- Preventive and Mitigative Measures Annual Summary

4.0 DEFINITIONS

- **HCA Affect** - The length of pipeline that intersects or tangentially touches a HCA or affects a HCA through a transport process.
- **NACE** - National Association of Corrosion Engineers.

1.0 PURPOSE

This procedure identifies the continual process of evaluation and assessment to maintain the integrity of the pipeline (line pipe or pipeline facility).

2.0 PROCEDURE

2.1 Once the Baseline Assessment on each pipeline has been completed, the Company will continue to:

Re-assess the pipeline at specified intervals as stated in this procedure.

Evaluate the integrity of each pipeline segment that affects a high consequence area.

The Company evaluates the pipeline as frequently as required based on the following to ensure pipeline integrity:

- The evaluation frequency is determined by the integration of pipeline data as specified in the Baseline Assessment Plan and re-assessment schedules are developed.
- During the evaluation, the results of previous baseline and periodic integrity assessments, gas pipeline risk assessments and decisions/findings during Pipeline Evaluation and Remediation.

2.2 Re-assessment Interval Guidelines

Unless a period of less than seven years is specified, each covered pipeline segment must be reassessed at a seven year interval. If the Company establishes a re-assessment interval for the covered segment that is greater than seven years, the Company will, within the seven year period, conduct a Confirmatory Direct Assessment on the covered segment and then conduct the follow up reassessment. Confirmatory Direct Assessment shall be performed in accordance with the confirmatory direct assessment process described in Section 2.5 of this procedure.

When the Company uses pressure testing or internal inspection as an assessment method, the re-assessment interval for covered segments is determined by:

- The identified threats listed in the Risk Assessment for the segment identified, on the analysis of the results from the last integrity assessment, and from data integration, or

- Using the intervals for different stress levels of pipeline specified in ASME B31.8S, Section 5, Table 3: “Integrity Assessment Intervals - Time-Dependent Threats Prescriptive Integrity Management Plan” or Section 7, Figure 4: “Timing for Scheduled Responses – Time-Dependent Threats Prescriptive Integrity Management Plan”.

- The maximum reassessment interval must not exceed 10 years for a pipeline operating at or above 50 percent Specified Minimum Yield Strength (SMYS) and 15 years for a pipeline operating below 50 percent SMYS. Choosing the maximum period allowed for re-assessment requires demonstration that enhanced preventive and mitigative measures for the segment have been implemented.

When the Company uses direct assessment as an assessment method, reassessment intervals for covered segments are determined according to Procedures PS-03-01-232: “External Corrosion Direct Assessment”, PS-03-01-238: “Dry Gas - Internal Corrosion Direct Assessment” and PS-03-01-240: “Stress Corrosion Cracking Direct Assessment”.

If a prior assessment was credited as a baseline assessment for a covered segment, the covered segment shall be reassessed by no later than December 17, 2009.

2.3 Waiver from Interval Greater Than Seven Years in Limited Situations

In the following limited instances, the Office of Pipeline Safety (OPS) may allow a waiver from a reassessment interval greater than seven years, but within the maximum allowable interval, if OPS find a waiver would not be inconsistent with pipeline safety:

- Lack of Internal Inspection Tools:

  - Justification is made for a longer assessment period for a covered segment if internal inspection tools are not available to assess the pipeline.

  - It is demonstrated that the inspection tool cannot be obtained within the required assessment period and must also demonstrate the actions taken to evaluate the integrity of the pipeline segment in the interim.

  - Notify the OPS (or State or local pipeline safety authorities if required) in accordance with Procedure PS-03-01-264: "IMP Communication Plan" 180 days before the end of the required reassessment interval that the Company may require a longer assessment interval and provide an estimate of when the assessment can be completed.

- Maintain Local Product Supply:

  - The Company shall show justification for a longer assessment period for a covered segment if the reassessment will shut off the local product supply and that alternative supply is not available.

  - Notify OPS or the authorized State agency in accordance with Procedure PS-03-01-264: "IMP Communication Plan" 180 days before the end of the required reassessment interval that the operator may require a longer assessment interval and provide an estimate of when the assessment can be completed.

2.4 Assessment Methods and Intervals

The Company determines the assessment/re-assessment methods for the pipelines operating at or above 30% SMYS in accordance with the following.

- If a reassessment interval greater than seven years is established, a confirmatory direct assessment shall be performed at seven-year intervals followed by a reassessment at the interval established by the Company. For example, if the reassessment is established at ten years, in the seventh year a confirmatory direct assessment shall be conducted followed by the reassessment in the tenth year from the assessment.

- The maximum reassessment interval shall not exceed the values shown in the following Table 1:

TABLE 1: MAXIMUM REASSESSMENT INTERVALS

Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test, or Direct Assessment	10 years (*)	15 years (*)	20 years (**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years plus ongoing actions specified in section 2.6 of this procedure.

(*) A confirmatory direct assessment shall be conducted by year 7 in a 10-year interval and years 7 and 14 in of a 15-year interval.

(**) A low stress reassessment or confirmatory direct assessment shall be conducted by years 7 and 14 of the interval.

Deviations from the above Table 1 are permitted if a performance-based integrity management program is used. No deviations are permitted with a prescriptive-based program. The Company is using a prescriptive-based program.

Pipelines operating below 30% SMYS shall also be reassessed using pressure tests, internal inspections, other equivalent technology, or direct assessment (external corrosion, internal corrosion, and stress corrosion cracking). However, if the reassessment interval is established at more than seven years, either a confirmatory direct assessment or a low stress reassessment shall be conducted at seven year intervals.

2.5 Confirmatory Direct Assessment

Confirmatory direct assessment is a reassessment alternative that may be used in certain limited circumstances. It may be used to identify damage resulting from internal corrosion and external corrosion only. It may be used whether the covered segment is operating above or below 30% SMYS. It must be used, subject to the limitation above, when the established reassessment interval is greater than seven years.

When the established reassessment interval is greater than seven years, a confirmatory direct assessment shall be conducted at seven-year intervals followed by a reassessment at the interval established by the Company. For example, if the reassessment interval is established at 15 years, then confirmatory direct assessments shall be performed at years seven and 14, and the reassessment at year 15.

For pipelines operating at less than 30% SMYS (low stress pipe), an additional alternative is low stress reassessment. Section 2.6 of this procedure describes the low stress reassessment process.

Confirmatory Direct Assessment for external corrosion shall meet the follow criteria:

- The Pre-assessment step for ECDA Regions as described in Procedure PS-03-01-232: “External Corrosion Direct Assessment”.

- The Indirect Inspection step as described in the external corrosion direct assessment procedure, except the inspection may be conducted using only one Indirect Inspection tool suitable for the application.

- The Direct Examination step shall be performed as described in the external corrosion direct assessment procedure with the following exceptions:

  - Excavation of all “Immediate” action indications is required in each ECDA Region.

  - Excavation of at least one high risk indication that meets the criteria of “Scheduled” action is required in each ECDA Region.

  - No excavation is required for indications categorized as “Monitored” indications.

- Remediate indications found during the Direct Assessment according to the requirements of ASME B31.8S and in accordance with

Procedure PS-03-01-252: "Schedule of Repair Requirements". If defects require immediate remediation, the Company shall reduce pressure in the pipeline segment using either ASME B31G or RSTRENG to calculate the required pressure reduction or reduce the pressure to 80% of the operating pressure level at the time the condition was discovered.

- Ensure remediation is consistent with Procedure PS-03-02-200 "Evaluation of Remaining Strength of Corroded Pipe".

- Reassessment intervals shall be established in accordance with the requirements of NACE Recommended Practice RP0502-2002.

Confirmatory Direct Assessment for internal corrosion shall meet the follow criteria:

- The Pre-assessment step for ICDA Regions as described in Procedure PS-03-01-238: "Dry Gas - Internal Corrosion Direct Assessment".

- The identification of ICDA Regions shall be identified as described in the internal corrosion direct assessment procedure.

- The identification of excavation locations and excavation as described in the internal corrosion direct assessment procedure, except that only one high-risk location in each ICDA Region may be identified for excavation.

- The direct examination and remediation shall be performed as described in the internal corrosion direct assessment procedure, except that one high-risk location is to be chosen in each ICDA Region for excavation.

2.6 Low Stress Reassessment

Low stress pipelines are defined as pipelines that operate at less than 30% SMYS.

The method described herein may be used for reassessment of low stress pipeline covered segments. The method addresses the threats of internal and external corrosion.

A baseline assessment of the covered pipeline segment must be conducted in accordance with the requirements of 49 CFR 192 Subpart O and the Company's Integrity Management Program procedures prior to implementing the low stress reassessment described herein.

2.7 External Corrosion

The Company shall take one of the following actions to address external corrosion on the low stress covered segment.

- Cathodically Protected Pipe
    - An electrical survey (that is, use of an indirect examination tool or method) shall be performed at least every seven years on the covered segment.
    - The results of the electrical survey shall be used as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment.
    - The evaluation shall consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- Unprotected Pipe or Cathodically Protected Pipe Where Electrical Surveys Are Impractical
    - If the covered segment is not cathodically protected or electrical surveys are impractical, leakage surveys shall be conducted at four-month intervals.
    - Areas of active corrosion shall be identified and remediated every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

2.8 Internal Corrosion

To address the threat of internal corrosion on a covered pipeline segment, the Company shall perform the following actions:

- A gas analysis for corrosive agents shall be conducted at least once each calendar year.

- Fluid sampling and testing shall be conducted periodically. At least once each calendar year the fluids removed from each storage field that may affect a covered segment shall be tested.

- At least once every seven years the gas sampling data and fluid testing data shall be integrated with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records and evaluated.

- The data integration and evaluation shall result in a list of documented remediation actions which shall be scheduled and implemented.

3.0 REFERENCES

3.1 Regulatory

- DOT 49 CFR Part 192

3.2 Industry Practices

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

3.3 Related Procedures/Supporting Documents

- PS-03-01-115, Risk Assessment Process

- PS-03-01-220, Baseline Assessment Plan Procedure

- PS-03-01-232, External Corrosion Direct Assessment Procedure

- PS-03-01-238, Dry Gas - Internal Corrosion Direct Assessment Procedure

- PS-03-01-240, Stress Corrosion Cracking Direct Assessment Procedure

- PS-03-01-250, Pipeline Evaluation and Remediation Procedure
- PS-03-01-252, Schedule of Repair Requirements Procedure
- PS-03-01-258, Preventive and Mitigative Measures Procedure
- PS-03-01-264, IMP Communication Plan Procedure
- PS-03-02-200, Evaluation of Remaining Strength of Corroded Pipe Procedure

3.4 Forms and Attachments

- None

4.0 DEFINITIONS

- **ASME B31G** - Supplement to ASME Code for Pressure Piping for the purpose of providing guideline information (criterion) for measuring and determining the remaining strength of corroded pipelines.
- **External Corrosion Direct Assessment (ECDA)** - ECDA is a structured process that is a method for establishing the integrity of underground pipelines.
- **ICDA Region** - An ICDA Region is bounded b a location where a new gas stream enters the pipe and the nearest location downstream of that point where the pipe slope exceeds the critical angle, given local gas velocity.
- **OPS** - Office of Pipeline Safety.
- **Specified Minimum Yield Strength (SMYS)** - Expressed in pounds per square inch, the minimum yield strength of the steel in pipe as required by the pipe product specifications.

1.0 PURPOSE

This procedure describes the process for managing changes to the Integrity Management Program.

The Company's Management of Change process is used for managing and controlling changes to the Program Description Document and supporting processes and procedures. This procedure describes the requirements for the documents generated as a result of implementing the Integrity Management Program.

2.0 PROCEDURE

2.1 The Company's Management of Change Process

The Company's Management of Change (MOC) process is applicable to all changes to a process, policy, procedure, standard, handbook or manual; and is also applicable to requests for the establishment of a new process, policy, procedure, standard, handbook, or manual. Specifically, any changes to the Integrity Management Program's Program Description Document or implementing processes or procedures shall be processed through the Company's MOC process. Also, any changes deemed necessary to other Company processes, policies, procedures, standards, handbooks, or manuals that interface with or support the Integrity Management Program shall also be processed through the Company's MOC process.

The Company's MOC process includes but is not limited to:

- Reason for change
- Authority for approving changes
- Analysis of implications
- Documentation of the change
- Communication of change to affected parties
- Time limitations

- Qualification of staff involved in the change

Changes processed through the Company's MOC process are initiated with a change request form that captures the relevant information about the change, such as document affected, description of change, and reason for change. The proposed change form and accompanying document with the proposed change is processed through the Change Management committee in accordance with the Company's MOC process.

The Director, Pipeline Integrity is a member of the Change Management Committee that reviews and approves changes to Company processes, policies, procedures, standards, manuals, and handbooks. Membership on the Change Management Committee assures that pipeline integrity and requirements of the Integrity Management Program are considered when changes are reviewed.

The Director, Pipeline Integrity shall maintain a Change Log for all changes to the Program Description Document and supporting processes and procedures (refer to Table 1 in Section 2.2 of this procedure). The Change Log shall identify the document, describe the change, the reason for the change, and the date of approval. The log may be either manual or computerized, such as an electronic spreadsheet or a word processing document.

2.2 Changes That Affect the Integrity Management Program

Various documents generated through implementation of the Integrity Management Program may require change from time to time for any number of reasons. The changes may result from:

- Pipeline equipment additions, deletions or modifications
- Product being transported
- Operating condition affecting the risk prioritization
- Spill/release control or other mitigation measures
- Flow rate or operating pressure

- Equipment or system restart after being out of service or not maintained for an extended period

- Remediation associated with surveillance and monitoring activities

- Procedure additions, deletions or revisions

- Right-of-Way land use

- Population growth or migration

- Regulatory additions, deletions or revisions

- New technologies and the applications

To determine the impact of changes such as those described above, Pipeline Integrity Department personnel considers the following at a minimum

- Have the potential impacts or affected impact zones been altered?

- Should data be added, deleted or modified?

- Does the change impact data or assumptions used during the risk assessment?

- Does this change affect inspection, prevention or mitigation plans?

- Should this change lead to a revision of the IMP?

- Does this change affect the integrity program for pipeline appurtenance equipment?

- Does this change impact any performance indication or audit criteria?

The following Table 1 identifies the types of changes that the Pipeline Integrity Department monitors, reviews, approves and records. For each type of change listed, the person responsible for monitoring, reviewing and recording the change and the person responsible for approving the change is listed.

Table 1: Changes Requiring Tracking, Review, and Approval

Change Description	Review & Record	Approve
Program Description, Processes, Procedures	Director, Pipeline Integrity	Change Management Committee
High Consequence Area Changes	Integrity Engineer	Manager, Pipeline Integrity
Threat Identification and Risk Assessment	Pipeline Integrity Engineer	Manager, Pipeline Integrity
Baseline Assessment Plan	Manager, Pipeline Integrity	Director, Pipeline Integrity
Class Changes	Pipeline Integrity Engineer	Manager, Pipeline Integrity
Maximum Allowable Operating Pressure Changes	Pipeline Integrity Engineer	Manager, Pipeline Integrity
Pipeline Facility Changes	Data Management Supervisor	Manager, Pipeline Integrity

If any of the changes above require a change in the IMP Program Description Document or the supporting IMP processes or procedures, the change shall be processed in accordance with the Company's Management of Change process.

2.3 Documentation

Pipeline Integrity Department personnel identified in Table 1 that are responsible for reviewing and recording the changes shall maintain a change log of approved changes. The log may be either manual or computerized, such as either an electronic spreadsheet or a word processing document.

The change log shall be used to record the affected document, a description of the change, reason for the change, date of change, and person that approved the change.

2.4 Communications

The Company shall notify the Office of Pipeline Safety (OPS) of any change to the Integrity Management Program that may substantially affect the program's implementation or may significantly modify the program or schedule for implementing the program elements. The Company shall also notify State or local pipeline safety authorities when either a covered pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. The Company shall provide the notification within 30 days after adopting this type of change into its program. Notification shall be in accordance with Procedure PS-03-01-264: "IMP Communication Plan".

Other changes identified in Table 1 shall be communicated to appropriate Company personnel in accordance with Procedure PS-03-01-264: "IMP Communication Plan."

3.0 REFERENCES

3.1 Regulatory

- 49 CFR Part 192

3.2 Industry Practices

- ASME B31.8S (2001)

3.3 Related Procedures/Supporting Documents

- PS-03-01-264, IMP Communication Plan Procedure
- Company Management of Change Process

3.4 Forms and Attachments

- None

4.0 DEFINITIONS

- None

1.0 PURPOSE:

The Company's Quality Program consists of the following:

Quality Assurance - Quality assurance is a programmatic review to determine whether an organization is properly implementing its processes and procedures. This is a compliance review. The second part of quality assurance is determining whether the processes and procedures being implemented achieve the desired outcome. This is an effectiveness review. The Company has developed this process outline for conducting the compliance reviews through audits. The effectiveness reviews are conducted as part of each of the individual processes that implement the integrity management program.

Quality Control - Quality control is the second major component of the Company's Quality Program. Quality control consists of a series of checks and balances that ensure that the steps in the processes and procedures are being implemented such that the desired results are achieved. These checks and balances are part of the individual processes. For example, the Process Tracking Documents are a major component of quality control since they serve as a check that each step was completed and the desired work products were produced and filed. Another example is Process C in the Quality Assurance process (PS-03-01-170) which is for a review for accuracy of all data collected during pipe excavations. Additionally, the process outlines contain similar steps for reviewing data, work products and decisions, which are all part of quality control.

2.0 PROCEDURE:

2.1 There are two major components that comprise quality assurance activities as they are related to the Integrity Management Program:

- IMP Status assesses the completeness of the program and the level of deployment and implementation within the organization.

- IMP Effectiveness assesses the degree to which the execution of the program conforms to its requirements, the quality of the execution and the quality of the results.

Requirements of a quality assurance program include documentation, implementation and maintenance of the program.

2.2 Quality Assurance Program:

The Company has assessed and developed processes in the IMP to support the following six required activities:

- Identify the processes that will be included in the quality management program.

- Determine the sequence and interaction of these processes.

- Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.

- Provide the resources and information necessary to support the operation and monitoring of these processes.

- Monitor, measure and analyze these processes.

- Implement actions necessary to achieve planned results and continued improvement of these processes.

2.3 Quality Assurance Program Related Documents

Documents included in the Quality Assurance Program are the Integrity Management Program and all its supporting documents. These are controlled, maintained and audited as defined by each IMP process. Examples of documented activities include, but are not limited to:

- Integrity Management Plan, including all supporting procedures
- Risk Assessments
- Integrity Management Reports
- Data Documents (for example, inspections, reports, surveys, etc.)
- Plans and schedules
- Analyses and justifications
- Changes
- OPS and other agency notifications

The IMP, including the Quality Assurance Program, will be reviewed and audited at predetermined intervals and result in recommended improvements. The following processes are established within the IMP:

- Employee recommendations for changes to IMP processes and procedures: Company Management of Change process

- IMP Audits: PS-03-01-268: "IMP Quality Assurance" procedure

- Internal/external notification of changes: PS-03-01-264: "IMP Communication Plan" procedure

2. 4 Quality Assurance Program Related Processes and Procedures

The Company requires and has an IMP procedure in place to ensure all personnel responsible for performance of the IMP are:

- Competent
- Aware of the program and all of its activities and/or processes
- Trained to execute the activities and/or processes within the program
- Documentation of such competence, awareness, qualification and the processes for their achievement

The Company will monitor the IMP to show that it is being implemented according to program procedures. Audits will be conducted in accordance with Section 2.6 of this procedure. Audits will review implementation of the various procedures and processes and applicable documentation that substantiates procedure and process compliance.

The Company has programs and procedures within the IMP, as applicable, for vendors and contractors performing IMP related work and all work is monitored by the Company's qualified personnel (personnel qualified under the Company's Operator Qualification Program).

2. 5 Quality Audits

The Director, Pipeline Integrity will schedule an annual audit of the Integrity Management Program and the Manager, Compliance will select the members of the audit team. The audit team may consist of persons from the Pipeline Integrity department as well as other departments in the Company.

The Manager, Compliance is responsible for performance of the audit. The purpose of the audit is to:

- Verify that the documentation exists that results from implementation of the Integrity Management Program
- Review processes and procedures to assure they are being implemented as written
- Review the processes and procedures to assure they are correctly implementing 49 CFR 192 Subpart O.

The annual audit is a spot check of records, not a 100 percent review of all records. However, if the audit results indicate a significant number of findings in a particular category, the auditors may expand their audit sample.

Appendix A provides an audit checklist for the audit.

A post-audit meeting will be conducted after the audit is completed and prior to completion of the audit report. The purpose of the meeting is to validate the results of the audit and identify findings and action items of the audit.

The audit team will prepare a final audit report that identifies the scope of the audit, a description of documents reviewed, and findings and action items.

The Manager, Pipeline Integrity will record action items on Form PS8144, Action Item Tracking, and track action items to completion. Resolution of action items, that is, how the action item was resolved (for example, a procedure was revised, a calculation was corrected, a standard computer report had a data element added) will be documented.

2.6 Annual dig data validation

2.6.1 The Manager, Pipeline Integrity shall assign a PI person to conduct a review of the data collected at dig locations excavated during the year.

2.6.2 Identify all dig locations that were excavated during the year.

- Includes dig locations in HCA covered segments

- Includes dig locations in non-covered segments identified and excavated as a result of implementing integrity assessment processes.

2.6.3 For each dig location, collect and review all data collected for the dig.

- Identify missing data.
- For data fields left blank, ensure an explanation was provided.
- Review for consistency in type of data collected (e.g., was pipe temperature only collected at half of the digs).
- Review data for inaccuracies.

2.6.4 Develop a written report of the findings of the review. Transmit the report to the Manager, Pipeline Integrity for action and to the Supervisor, Data Management for recordkeeping.

- Identify missing data
- Identify data inconsistencies
- Identify data inaccuracies.

2.6.5 The Manager, Pipeline Integrity shall develop an action plan for addressing the results of the dig location data review and shall transmit to the appropriate personnel for action, if needed, and to the Supervisor, Data Management for recordkeeping.

2.7 Documentation

The Company will retain audit reports, action item tracking logs, and other supporting documentation, including action item resolutions, with the permanent Integrity Management Program records.

3.0 REFERENCES:

3.1 Regulatory:

- DOT 49 CFR Part 192

3.2 Industry Practices:

- None

3.3 Related Procedures/Supporting Documents:

- PS-03-01-170, Quality Assurance Process
- PS-03-01-216, Threat Identification and Risk Assessment Procedure
- PS-03-01-224, Assessment Methods Selection Flowchart Procedure
- PS-03-01-250, Pipeline Evaluation & Remediation Procedure
- PS-03-01-252, Schedule of Repair Requirements Procedure
- PS-03-01-254, Threat Prevention & Repair Chart Procedure
- PS-03-01-258, Preventive & Mitigative Measures Procedure
- PS-03-01-260, Reassessment Guidelines Procedure
- PS-03-01-262, Methods to Measure Program Performance Procedure
- PS-03-01-264, IMP Communication Plan Procedure
- PS-03-01-272, IMP Personnel Qualification Requirements Procedure
- Company Management of Change Process
- Operator Qualification Program
- Public Awareness Program

3.4 Forms and Attachments

- PS8144, Audit Action Item Tracking Form

4.0 DEFINITIONS

- None

APPENDIX A
Audit Checklist

Category: HCA Segment Identification

- Have all pipeline segments been reviewed and HCA segments identified and recorded?
- Has the method (Method 1 or Method 2) for identifying each HCA been recorded?
- Has the location of HCAs been recorded?
- Has the formula for calculating the potential impact radius been correctly applied?
- Review Identified Site Information Sheets to determine that HCAs were correctly identified.
- Are population density surveys conducted annually, the results reviewed, and adjustments made to existing HCAs, or new HCAs are identified?
- Is the method (Method 1 or Method 2) of identifying new HCAs or revising existing HCAs identified?

Category: Baseline Assessment Plan

- Was a Baseline Assessment Plan developed for all baseline identified HCAs?
- For 2006 and subsequent years, has a Long Term Assessment Plan been developed that incorporates assessments, reassessments, remediations and mitigations for all currently identified and newly identified HCAs?
- For 2006 and subsequent years, has an Annual Assessment Plan been developed that identifies assessments, reassessments, remediations and mitigations scheduled for the calendar year?
- Review Assessment Method Selection Guides to verify that assessment plans (Baseline, Long Term, Annual, Segment) have correctly identified the type of assessment.

- Verify that the Baseline, Long Term, and Annual assessment plans identify a general schedule for performing assessments, reassessments, remediations and mitigations and are based on risk rank and severity, subject to the practicalities of conducting particular types of assessments, business needs, and environmental considerations, such as weather.

- Verify that actual progress is consistent with the plans.

- Verify that changes to plans are documented.

- Verify that changes to planned assessment methods are explained and documented.

- Verify that if schedules are not met that appropriate notifications to OPS have been made.

Category: Threat Identification and Risk Assessment

- Verify that the categories of failure identified in Procedure PS-03-01-216: “Threat Identification and Risk Assessment” have been considered and evaluated for each covered pipeline segment (HCA) and documented.

- Verify that a risk assessment of the covered segments was conducted.

- Verify that risk validation is documented.

- Verify that changes to the risk model are documented.

- Verify that new risk assessments are performed when new pipeline information is available.

Category: External Corrosion Direct Assessment

- Verify that more restrictive criteria is applied when ECDA is applied to a covered segment for the first time.

- Verify that pipeline data is gathered and integrated.

- Verify that for missing or suspect data conservative assumptions are used and documented.

- Verify that ECDA Regions are identified and documented.
- Verify that a feasibility assessment was conducted and documented.
- Verify that indirect inspection tool selection was identified and documented.
- Verify that indications found during indirect inspection have been identified and evaluated and that severity has been classified.
- Verify that direct examinations are scheduled and performed in accordance with the severity classification of the indications and documented.
- Verify that where corrosion defects are found during direct examination that remaining strength is determined.
- Verify that the root cause of significant corrosion activity is documented.
- Verify that corrosion defects are remediated or scheduled for remediation.
- Review remaining strength calculations and verify that the reassessment interval has been correctly identified and documented.
- Verify that at least one validation direct examination was performed and the results were documented.

Category: Dry Gas Internal Corrosion Direct Assessment

- Verify that system analyses and feasibility assessments were performed and documented.
- Verify that more restrictive criteria are applied when ICDA is applied to a covered segment for the first time.
- Verify that pipeline data is gathered and integrated.
- Verify that for missing or suspect data conservative assumptions are used and documented.
- Verify that DG-ICDA Regions are identified and recorded.

- Verify that pipeline elevation profile data is collected and recorded.
- Verify that critical angles of inclination are performed and recorded.
- Verify that dig locations are identified based on integration of pipeline elevation profile and critical angle of inclination data.
- Verify that direct examinations are performed and documented.
- Verify that nondestructive testing is performed and the results recorded.
- Verify that nondestructive testing results are evaluated and severity of defects is recorded.
- Verify that remediations are performed or scheduled.
- Verify that remaining strength is calculated and recorded and the reassessment interval is determined and recorded.
- Verify that the need for internal corrosion monitoring is evaluated and implemented as appropriate, and documented.

Category: Stress Corrosion Cracking Direct Assessment

- Verify that pipeline data is gathered and integrated.
- Verify that for missing or suspect data that conservative assumptions are used and documented.
- Verify that feasibility assessment is conducted and documented.
- Verify that dig locations are identified and documented.
- Verify that direct examinations are performed and documented.
- Verify that pressure tests are performed and documented.
- Verify that remediations are performed based on results of direct examinations and documented.

- Verify that reassessment intervals are determined and documented.

Category: In-Line Inspection

- Verify that a Preliminary Report was issued and that immediate repair conditions were identified in the report.
- Verify that the Company excavated and remediated the immediate repair conditions.
- Verify that the date of discovery of conditions was identified and documented in accordance with Procedure PS-03-01-252: "Schedule of Repair Requirements".
- Verify that conditions that were identified by the ILI tool run were categorized by severity.
- Verify that excavations were performed for each severity category of condition and documented (verification of tool accuracy).
- Verify that remaining strength calculations were performed and documented.
- Verify that the ILI vendor issued a Final Report for the tool run and that the report was accepted by the Company.
- Verify the Final Report was analyzed by the Company with regard to metal loss indications, geometry indications, and crack indications and that indication severity was assessed.

Category: Pressure Testing

- Verify that results of pressure tests are documented.
- Verify that remediations were performed as indicated by the results of the pressure test and documented.

Category: Remediation

- Verify that the actual date of discovery of a condition is documented in accordance with Procedure PS-03-01-250: "Pipeline Evaluation and Remediation".

- Verify that condition discovery is documented within 180 days of completion of the assessment.

- Verify that conditions are scheduled for remediation in accordance with evaluated severity.

- Verify that temporary operating pressure reductions are made and documented.

- Verify that conditions are categorized as immediate, scheduled, and monitored in accordance with the requirements of Procedure PS-03-01-252: “Schedule of Repair Requirements”.

- Verify that notifications to OPS are made if the repair schedule cannot be met or pressure reductions cannot be made, and justifications are documented.

- Verify that conditions are remediated in accordance with the schedule and documented.

- Verify that if temporary pressure reductions extend for more than 365 days that a technical justification has been prepared that the continued pressure reduction will not jeopardize integrity of the pipeline.

- Verify that scheduled and monitored conditions are included in the annual assessment and remediation schedule.

- Verify that reassessment intervals for monitored conditions have been determined and documented.

Category: Continual Evaluation and Assessment

- Verify that there is an annual review of pipeline data for new and changed information, and review of results of assessments and remediations and mitigations, and that threat identification, risk assessment, assessment plans and remediation schedules are updated based on these reviews.

- Verify that reassessment methods are documented on the Assessment Method Selection Guide in Procedure PS-03-01-224, “Assessment Methods Selection Flowchart”.

- Verify that confirmatory direct assessment is identified for ECDA or ICDA when the reassessment interval is greater than seven years.

- Verify that if low stress reassessment is implemented that the reassessment is conducted in accordance with procedural requirements (Procedure PS-03-01-260: “Continual Process for Evaluation and Assessment”) and documented.

Category: Preventive and Mitigative Measures

- Verify that documentation exists that identifies and justifies the selected preventive and mitigative measures.

- Verify that preventive and mitigative measures are identified in accordance with Procedures PS-03-01-254: “Threat Prevention and Repair Chart” and PS-03-01-258: ”Preventive and Mitigative Measures”.

Category: Performance Measures

- Verify that performance is measured semi-annually for the four performance measures that are reported to OPS.

- Verify that semi-annual performance is reported to OPS by August 31 and February 28 of each year.

- Verify that additional performance measures identified in Procedure PS-03-01-262: “Methods to Measure Program Performance” are documented.

Category: Management of Change

- Verify that changes to the Integrity Management Program, Processes and Procedures are processed through the Company Management of Change Process and documented.

- Verify that documentation of changes includes basis for change and analysis of implications.

- Verify that changes are approved prior to implementation.

- Verify that training is conducted prior to changes going into effect.

- Verify that OPS is notified of significant changes.
- Verify that changes to plans, HCAs, MAOP, threat identification, risk assessments, Class changes, and pipeline facility changes are documented.

Category: Personnel Qualification

- Verify that personnel meet the qualification requirements for their assigned tasks.
- Verify that Employee Qualification Summaries are maintained in eWebOQ and are up to date.

Category: Communications

- Verify that required notifications to OPS and state and local regulatory agencies are made as required and documented.
- Verify that communications with the public, public officials, emergency responders, and landowners and tenants along the ROW are conducted through the Company's Public Awareness Program.
- Verify that there are internal communications within the Company using e-mails, the Company's e-newsletter, or other means.
- Verify that safety concerns raised by OPS or state or local regulatory agency are addressed and documented.
- Verify that documents requested by OPS or other state or local regulatory agencies are submitted.

Category: Quality Assurance

- Verify that audit findings from previous audits were translated into appropriate action items.
- Verify that action items were completed.

1.0 PURPOSE

1.1 Quality Auditing and Oversight of Contractors and Vendors describes the methodology and requirements for conducting compliance audits and oversight reviews of Contractors and Vendors performing pipeline integrity related work for the Company.

1.2 Contractors or vendors that provide a service shall be subject to a compliance audit. For purposes of this procedure, “services” is defined as activities conducted in the field, such as in-line inspection. Contractors or Vendors that provide a technical or engineered work product shall be subject to oversight reviews. An example of a work product would be a company performing aerial photography interpretation and integration with pipeline alignment sheets. Development of the work product may or may not involve field work.

1.3 Contractors and Vendors performing pipeline integrity related field work on pipelines shall be subject to annual compliance audits or at least one compliance audit for short duration contracts and purchase orders (contracts and purchase orders expected to be completed within 12 months of issuance).

1.4 Compliance audits are conducted at least annually at the Contractor’s/Vendor’s offices and in the field to measure compliance with the Company’s requirements, standards and associated regulations. The compliance audit uses a consistent methodology to identify exposures and areas of improvement, and to promote consistency within the Company’s pipeline integrity program.

1.5 Contractor and Vendor oversight includes observation of field activities, if applicable, performed by Contractors and Vendors and technical review of submitted work products. Oversight activities are performed on a routine basis, such as daily or weekly.

1.6 Company personnel assigned to audit or oversight activities shall be conversant with the type of work being performed by the Contractor or Vendor. Pipeline Integrity shall be the primary source of personnel for auditing or oversight activities; however, for some technical work, other Company departments may have the best source of expertise and use of that expertise should be employed by Pipeline Integrity.

1.7 This procedure does not apply to contract personnel filling positions within the Company's organizational structure and performing work directed by the Company.

2.0 PROCEDURE - COMPLIANCE AUDITING

2.1 General

2.1.1 The Company utilizes Contractors and Vendors for various pipeline integrity activities and will perform audits periodically to ensure compliance with the Company's requirements and related regulations and industry standards as outlined in the purchasing documents.

2.1.2 Written procedures developed and used by Contractors and Vendors employed by the Company and technical and commercial specifications included in the purchasing documents shall form the general basis for compliance auditing.

2.2 Responsibilities

2.2.1 Responsibility: Manager, Pipeline Integrity

- Establish, maintain and distribute an annual compliance audit schedule to all affected company employees, Contractors and Vendors. Attachment A is the audit schedule form.
- Ensure a compliance audit is conducted on a regular basis, such as annually, of each of the Contractors and Vendors currently performing pipeline integrity related work.
- For short-term contracts (contracts with a duration of 12 months or less), ensure a compliance audit is conducted at least once prior to the end of the contract/purchase order. It is desirable that the audit be conducted within the first third of the contract/purchase order initiation (for example, a contract or purchase order with an estimated duration of six months should be audited within the first two months of the start of the contract/purchase order).
- Assign Audit Team Leaders for each audit and work with the Audit Team Leader to select the audit team members.

- Publish audit findings with Company-wide implications to the affected Company managers.

- Review this audit procedure annually and update as needed to ensure effectiveness and compliance.

2.2.2 Responsibility: Audit Team Leader

- Select audit team members.

- Notify Contractor or Vendor of planned compliance audit at least 30 days prior to start of audit.

- Develop an audit plan based on the Contractor's or Vendor's procedures, and the technical and commercial specifications included in the purchasing documents.

- Conduct the compliance audit in accordance with the provisions of this procedure.

  - Conduct an entrance meeting to identify to the Contractor/Vendor what will be reviewed.
  - Review documents and activities in accordance with the plan.
  - Conduct an exit meeting to provide the Contractor/Vendor the preliminary audit findings.

- Develop Audit Final Report and transmit to Contractor/Vendor within 30 days of the end of the audit for action.

- Establish due dates and assign accountability for follow-up for each finding and recommendation. Notify the Contractor/Vendor of the due date for resolution.

- Identify findings that have company-wide implications and forward to the Manager, Pipeline Integrity for review.

- Track each audit finding to completion and forward exceptions to the Manager, Pipeline Integrity for follow-up.

- Transmit the audit report to the Supervisor, Data Management for recordkeeping.

2.3 Audit Implementation

2.3.1 An Audit Plan shall be developed for each audit. Attachment B provides an example audit plan that must be modified for the specific contractor being audited. The Audit Plan shall be based on the following items typically reviewed at the Contractor's/Vendor's offices:

- Contractor's/Vendor's written procedures
- Contractor's/Vendor's personnel training program, training records, certifications and qualifications.
- Contractor's/Vendor's quality assurance program
- Contractor's/Vendor's Operator Qualification plan records
- Adequacy of Contractor's/Vendor's data management procedures and practices to ensure accurate data submittals
- Contractor/Vendor compliance with environmental and safety requirements
- Required licenses and permits
- Verification that Contractor's/Vendor's written procedures meet applicable regulatory requirements and best practices outlined in industry standards.
- If the Contractor/Vendor has previously been audited by the Company, the previous compliance audit reports and follow-up actions shall be reviewed to ensure that the current compliance audit includes a review of areas of previous significant non-compliance.

2.3.2 The Audit Plan shall include the following items which are typically reviewed at the Contractor's/Vendor's field work locations.

- Validation of personnel and operator qualification covered tasks

- Validation of applicable level of certification as it applies to tasks being performed
- Observance of tasks being performed are performed in accordance with contractor's procedures
- Data collecting equipment is maintained, calibrated and in good working condition
- Compliance with all environmental and safety requirements
- Compliance with OSHA excavation requirements
- One-Call procedure compliance
- Minimization of right-of-way and property damage
- Trash and debris cleanup at jobsite

2.3.3 An audit is a review of a representative sample of documents and activities to determine, for example, that procedures are being followed and are accurate and comply with standards and regulations. The audit sample size shall be increased if there are findings of non-compliance to determine whether the non-compliant item is a singular item or a pervasive issue.

2.3.4 The Audit Team shall use the Audit Plan as the guide for document review and field observations.

- Identify each document reviewed and the review results. The review results shall be recorded as satisfactory or unsatisfactory.
- For items reviewed that are unsatisfactory, describe in detail the non-compliance.
- Identify each field activity observed and whether the activity was satisfactory or unsatisfactory.
- For each unsatisfactory field observation describe in detail the non-compliance.

2.3.5 At the conclusion of the document review and field observation period the audit team shall conduct an exit meeting with the contractor to provide a summary of the preliminary audit results.

2.3.6 The audit team shall prepare a written audit report within 30 days of completion of the audit.

- The audit report shall identify all items reviewed and the results of the review.
- For each item of non-compliance the basis for the non-compliance and a recommended resolution shall be identified.
- The audit report shall identify due dates for resolution of the non-compliances by the Contractor/Vendor.
- The Audit Team Leader shall review the audit findings with the Manager, Pipeline Integrity prior to issuing the report to the Contractor/Vendor.

2.3.7 After reviewing with the Manager, Pipeline Integrity, the Audit Team Leader shall transmit the audit report to the Contractor/Vendor for action and to the Supervisor, Data Management for recordkeeping.

2.3.8 The Audit Team Leader (with assistance by the audit team as needed) shall monitor and record the resolutions implemented by the Contractor/Vendor.

3.0 PROCEDURE - OVERSIGHT (Work Product Contractors and Vendors)

3.1 General

3.1.1 The Company utilizes Contractors and Vendors to develop engineered or technical work products for various pipeline integrity activities and will perform oversight reviews routinely to ensure the work product meets the Company's requirements and is in accordance with the purchasing documents.

3.1.2 Technical and commercial specifications included in the purchasing documents shall form the general basis for oversight reviews.

3.2 Responsibilities: Manager, Pipeline Integrity

3.2.1 Identify Contractors and Vendors providing work products for the year.

3.2.2 Assign a Pipeline Integrity Engineer or Project Manager to oversee the Contractor's or Vendor's development of the work product.

3.2.3 Meet routinely with the Pipeline Integrity Engineer to ascertain progress towards development of the work product.

3.3 Responsibilities: Pipeline Integrity Engineer or Project Manager assigned to Contractor/Vendor oversight

3.3.1 Review the purchasing documents, especially the technical and commercial specifications to understand what the work product is and the work scope.

3.3.2 Develop a list of items to be checked routinely to ascertain progress in developing the work product.

3.3.3 Develop a list of items to be checked to determine the accuracy and completeness of the work product that is delivered.

3.3.4 Implement oversight activities in accordance with Section 3.4 below.

3.3.5 If development of the work product involves field work, observe field activities for compliance with Company standards regarding safety, environmental protection, land clearing, excavation, or other relevant standard.

3.3.6 Stop field work until Contractor or Vendor brings activities into compliance.

3.3.7 When the work product is delivered, "test" the product for accuracy and completeness using the list developed in Section 3.3.3.

3.4 Oversight Implementation

3.4.1 Using the checklists developed in Section 3.3, monitor Contractor or Vendor activities on a routine (daily/weekly/monthly) basis to ascertain progress, issues, accuracy and completeness of the work product being developed.

3.4.2 Report progress and issues routinely to the Manager, Pipeline Integrity.

3.4.3 Work with the Contractor or Vendor to ensure all issues are addressed.

3.4.4 Validate the work product when it is delivered for accuracy and completeness.

4.0 PROCEDURE - OVERSIGHT (Field Services Contractors and Vendors)

4.1 General

4.1.1 The Company utilizes Contractors and Vendors to perform field services such as in-line inspection or pipeline pressure testing or excavation. In addition to annual compliance audits, the field activities of these types of Contractors and Vendors shall be observed on a daily basis.

4.1.2 Technical and commercial specifications and the scope of work description included in the purchasing documents shall form the general basis for oversight reviews.

4.2 Responsibilities: Manager, Pipeline Integrity

4.2.1 Use the Audit Plan developed in Section 2.3 and identify the Contractors or Vendors providing field service work for the year.

4.2.2 Normally, field teams in each Region Operations unit assigns employees to provide daily oversight of contractor activities. For those Contractors and Vendors without an assigned Company observer, assign a Pipeline Integrity Engineer or Project Manager to oversee the Contractor's or Vendor's field activities.

4.2.3 Meet routinely with the Pipeline Integrity Engineer or Region Office personnel to ascertain status of contractor activities.

4.3 Responsibilities: Pipeline Integrity Engineer or Project Manager assigned to Contractor/Vendor oversight

4.3.1 Review the purchasing documents, especially the technical and commercial specifications and scope of work description to understand what the scope of contractor activities.

4.3.2 Implement oversight activities in accordance with Section 4.4 below.

4.3.3 Stop field work as necessary until Contractor or Vendor brings activities into compliance.

4.3.4 Develop daily activities reports and transmit daily to the Manager, Pipeline Integrity for review.

4.4 Oversight Implementation

4.4.1 Use the technical and commercial specifications as a guide, and observe the daily activities of the Contractor/Vendor.

4.4.2 Inspect or accept Contractor/Vendor work as specified in the purchasing documents and Company specifications.

- Normally, inspection and acceptance of Contractor/Vendor work performed to date is conducted by field teams in the Company's Region Offices. The Pipeline Integrity field observer shall notify the appropriate Region Office that an inspection or acceptance is required in the field.

- In some cases a purchase order is issued for field work to be performed under the direct supervision of Pipeline Integrity. An example of this would be a Contractor/Vendor performing external corrosion direct assessment activities such as a close interval survey. The Pipeline Integrity field observer shall inspect any items requiring Company inspection or accept/approve items requiring Company acceptance/approval prior to the Contractor/Vendor continuing with the work plan.

4.4.3 Prepare a daily activities report and transmit to the Manager, Pipeline Integrity for review. The daily activities report shall describe the general weather and field conditions, activities for the day, issues encountered, resolutions implemented, and any other pertinent facts or observations.

4.4.4 Work with the Contractor or Vendor to ensure all issues are addressed.

5.0 REFERENCES:

5.1 Regulatory:

- Department of Transportation 49 CFR 192 Subpart O

5.2 Industry Practices:

- None

5.3 Related Procedures and Supporting Documents:

- PS-03-01-268, IMP Quality Assurance Procedure
- PS-03-01-170, Quality Assurance Process

5.3 Forms and Attachments:

- Attachment A: Audit Schedule
- Attachment B: Sample Audit Plan

6.0 DEFINITIONS:

- None

Attachment A

Audit Schedule for Year __________

Contractor	Scope of Work	Contact Person	Telephone Number	Audit Start Date	Audit End Date	Date Audit Competed	Follow-up Date	Auditors

Attachment B

CONTRACTOR/VENDOR COMPLIANCE AUDIT FORM				
Contractor/Vendor Company Name / Field Area:				Date:
Auditor:				
Requirements	**Yes**	**No**	**N/A**	**Comments**
Section 1: Performed at the Contractor's/Vendor's Office				
1. Does the contractor/vendor have a training program in place?	☐	☐	☐	
2. Does the training program have a written process for review, updating and approval?	☐	☐	☐	
3. Does the training program meet the Company's standard for discipline certification/qualification?	☐	☐	☐	
4. Does the contractor/vendor have a Quality Assurance (QA) program in place?	☐	☐	☐	
5. Does the QA program ensure auditing and validation of employees' training?	☐	☐	☐	
6. Does the contractor/vendor comply with the Company's Operator Qualification (OQ) program?	☐	☐	☐	
7. Does the QA program ensure auditing and validation of employees' OQ tasks qualifications?	☐	☐	☐	
8. Does the contractor's/vendor's Quality Control Program adequately ensure the quality of the Company's field data collected?	☐	☐	☐	
9. Are the contractor's/vendor's data management procedures and best practices adequate to ensure accurate data is submitted to the Company?	☐	☐	☐	
10. Is the contractor/vendor in compliance with the Company's environmental and safety requirements?	☐	☐	☐	
11. Has the contractor/vendor obtained all required licenses and permits?	☐	☐	☐	

ATTACHMENT B (Cont'd)

CONTRACTOR/VENDOR COMPLIANCE AUDIT FORM

Contractor/Vendor Company Name / Field Area: | Date:

Auditor:

Requirements	Yes	No	N/A	Comments
Section 1: Performed at the Contractor's/Vendor's Office (Cont'd)				
12. Does the contractor/vendor have written procedures to support performed services?	☐	☐	☐	
13. If so, review the following and determine if they meet the Company's and applicable regulatory requirements:				
14. Procedure Number and Title	☐	☐	☐	
15. Procedure Number and Title	☐	☐	☐	
16. Procedure Number and Title	☐	☐	☐	
17. Procedure Number and Title	☐	☐	☐	
18. Procedure Number and Title	☐	☐	☐	
19. Procedure Number and Title	☐	☐	☐	
20. Procedure Number and Title	☐	☐	☐	
21. Procedure Number and Title	☐	☐	☐	
22. Procedure Number and Title	☐	☐	☐	
23. Procedure Number and Title	☐	☐	☐	
24. Procedure Number and Title	☐	☐	☐	
25. Procedure Number and Title	☐	☐	☐	
26. Procedure Number and Title	☐	☐	☐	
27. Procedure Number and Title	☐	☐	☐	
28. Procedure Number and Title	☐	☐	☐	
29. Procedure Number and Title	☐	☐	☐	
30. Procedure Number and Title	☐	☐	☐	
31. Procedure Number and Title	☐	☐	☐	
32. Procedure Number and Title	☐	☐	☐	
33. Procedure Number and Title	☐	☐	☐	
34. Procedure Number and Title	☐	☐	☐	
35. Procedure Number and Title	☐	☐	☐	

1.0 PURPOSE

The purpose of this procedure is to provide instruction for conducting the Population Density and HCA Field Survey. The instruction will include a list of the information to be recorded in each different type of area and how it needs to be recorded.

2.0 PROCEDURE

2.1 Information, Tools and Materials Required for Population Density and HCA Field Survey.

The field team will receive an automated work order from the Maintenance Management System (MMS) system and two (2) copies of alignment sheet maps for the pipeline (or pipeline section) to be surveyed. Each pipeline (or pipeline section) will be surveyed annually.

The work order will state specifically what pipeline or section of pipeline is to be surveyed.

The alignment sheet map (map) will consist of the centerline of the pipeline displayed on an aerial background image with a minimum of the following additional information:

- A band to indicate the PIR distance
- A band to indicate the 660 foot buffer
- All available Pipeline feature information
- MAOP
- All structures in the database (either confirmed or unconfirmed).
- Identified Sites, including the name, if available
- A legend and drawing scale

2.2 General Guidelines

The field team member(s) will then conduct the survey on the pipeline (or pipeline section) using the following general guidelines:

2.2.1 Any marks made on the map should be in a high contrast, colored ink to make it stand out from the original text on the maps. It should be dark enough to be easily read, but light enough that it would not appear black.

2.2.2 Any structure or Identified Site (IS) that is indicated correctly on a map requires no further action.

2.2.3 When adding a structure (except single family homes) to the map, include as much available information as possible (distance from pipeline, business name, number of occupants, phone number, etc).

2.2.4 Structures will be added by placing a “dot” on the map at the appropriate location and indicating what the structure is used for. The codes at the bottom of the alignment sheet can be used to save time (for example, a “C26” code would indicate the dot represents a Single Family Residence).

2.2.5 Any structure or IS that is indicated on the map but no longer exists will be marked through with an “X” and a note added to indicate that it is no longer there.

2.2.6 Identify and mark any structure where the use of the structure has changed. Examples would be a single family home becoming a day care, or a restaurant becoming an office building.

2.2.7 GPS coordinates will be taken for all new IS locations. For new IS’s outlined by a polygon (recreation areas, schools, etc.), GPS coordinates should be used to define the polygon corners.

2.3 Identified Sites

2.3.1 Any new IS that is within the PIR or 300’ (whichever is greater) will be marked on the map and have an Identified Site Information Sheet (Form PS 8132) completed for it. This includes the distance from the IS to the pipeline and GPS coordinates. These coordinates will be maintained in electronic format and sent to Data Integrity when the work order is complete. The instructions for filling out this form are included on the form.

2.3.2 The Identified Site Information Sheets will be attached to the map by the field team and returned to Data Integrity with the map.

2.3.3 A structure containing 20 or more people will be marked as a “C24”. Examples would be office buildings, restaurants, gas stations, etc.

2.3.4 An apartment complex will be marked as a “C25”.

- If new apartment buildings are found within the PIR or 660 feet (whichever is greater), the information on the map and Identified Site Information Sheet should include the apartment complex name, phone number, and number of apartments per building.

2.3.5 Schools

- Any unmarked school that has any part of the school property within the PIR or 300 feet (whichever is greater), will be marked on the map. Schools will be marked as a “C21”.

- The polygon (boundary) drawn around the school should include all of the school property accessible to students.

2.3.6 Recreation Areas

- Any unmarked recreation area/facility that has any part within the PIR or 300 feet, will be marked on the map. The polygon (boundaries) around outdoor areas/facilities should be used to define the area/facility.

- Examples include, but are not limited to, playgrounds, parks, beaches, ballparks, stadiums and golf courses.

2.3.7 Churches

- Any unmarked church should be drawn onto the map. Churches will be marked as a “C29”. Always include the church’s full name and, if possible, the phone number.

- Most rural churches will not meet IS criteria. However, a church can become an IS for several reasons:

  - The church staff working at the building totals 20 or more persons at one time.

  - The church has regular meetings (5 days per week, 10 weeks per year) with 20 or more people.

  - The church has a day care, school or equivalent activity.

- The church has an outdoor play area that is used by 20 or more people at least 50 times each year.

- Fill out an Identified Site Information Sheet on any unmarked church that meets the IS criteria.

2.3.8 Cemeteries

- Any unmarked cemeteries should be drawn (use perimeter) onto the map. Cemeteries will be marked as “C28”.
- A cemetery can become an IS if they have 50 outdoor funerals/activities per year which are attended by 20 or more people.
- Fill out an Identified Site Information Sheet on any unmarked cemetery that meets the IS criteria.

2.3.9 Facilities

- “Facility” is a generic term used to identify a building occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.
- Some examples of facilities include: hospitals, prisons, schools, day-cares, retirement homes, and assisted living centers.

2.4 Structures Intended for Human Occupancy

2.4.1 Any new structure intended for human occupancy (SIHO) located within the PIR or 660 feet (whichever is greater) will be marked on the map.

2.4.2 A single-family structure will be marked as a “C26”.

2.4.3 Unoccupied businesses or homes count as SIHO if there is intent to re-occupy the structure (for sale/rent sign, etc). Buildings which are no longer suitable for habitation (a falling down farm house) can be removed from the map.

2.5 Pipeline Alignment

2.5.1 If the pipeline is found to be located incorrectly on the map, it will be drawn in by hand to accurately represent the pipeline location.

2.6 Road Crossings and Railroad Crossings

2.6.1 Any road crossings or railroad crossings not accurately indicated on the map will be drawn in by hand.

2.6.2 Any road or railroad which lies within the pipeline ROW and is not accurately indicated on the map will be drawn in by hand.

2.6.3 If a road (near the pipeline) is incorrectly labeled, write the correct name on the map.

2.7 Utility Crossings

2.7.1 Any pipelines, power lines, public utilities (sewer, water, electric, cable, etc) crossing the Company pipeline which are not accurately depicted, will be corrected on (or added to) the map.

2.7.2 Any power lines that parallel the pipeline or share a Right of Way should be added to the map, if not already there.

2.8 Exposed Pipe and Unsupported Spans

2.8.1 Add or remove any sections of exposed pipe or unsupported spans which are not correctly depicted on the map.

2.8.2 Unsupported Pipe Spans are defined as locations where the pipeline is completely exposed - meaning the top, sides, and bottom of the pipe.

2.8.3 Examples include, but are not limited to, areas where the pipeline spans small ditches, creeks, gullies, ravines, rivers, and lakes.

2.8.4 Segments of pipelines specifically designed to be above ground are not considered to be exposed or unsupported pipe.

2.9 Miscellaneous Structures, Facilities and Areas

2.9.1 It is impossible to list every structure, facility or area that might allow for public congregation near a pipeline. Any structure, facility or area not mentioned in this procedure, but in the judgment of a company employee, may impact population densities along a pipeline should be marked on the map.

2.9.2 See paragraphs 2.3 and 2.4, if applicable.

2.10 Documentation

Upon completion of the Population Density and HCA Field Survey for any pipeline or pipeline section:

2.10.1 In the event that there are no changes made on a particular map, that map should have “No changes required” written on it in large enough letters to be easily seen during evaluation.

2.10.2 All maps will then be forwarded to Data Integrity. Each map will have the name of the team member who performed work and can answer questions written legibly on the map, including a contact phone number.

2.10.3 Electronic files of GPS data shall be forwarded to Data Integrity. Each alignment sheet will have a separate electronic file.

3.0 REFERENCES

- Regulatory:
  - DOT Part 192 Subpart O
- Related Policies/Supporting Documents:
  - PS-03-03-100, Population Density and HCA Field Survey Process

4.0 DEFINITIONS

- **Potential Impact Circle (PIC)** - A circle of radius equal to the Potential Impact Radius
- **Potential Impact Radius (PIR)** - The radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. It is commonly referred to as the “CFER circle”. Calculated as .69 (for natural gas) multiplied by the square root of the product of MAOP and the square of the diameter.

$$PIR = 0.69\sqrt{p \times d^2}$$ (in feet)

Where p = MAOP (in pounds per square inch)
d = Nominal diameter of the pipeline (in inches)

Note: A 30 inch diameter pipeline with a MAOP of 1,000 psi generates a PIR of 655 feet. Any pipeline with a larger diameter and/or a larger MAOP will generate a PIR which exceeds 660 feet.

- **Identified Site** - An Identified Site is defined in CFR 49, Part 192, Subpart O as:

  - An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) month period. (The days need not be consecutive.) Examples include, but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility.

  - A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive.) Examples included, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks.

  - A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include, but are not limited to, hospitals, prisons, schools, day care facilities, retirement facilities, or assisted-living facilities.