Magellan Pipeline Company

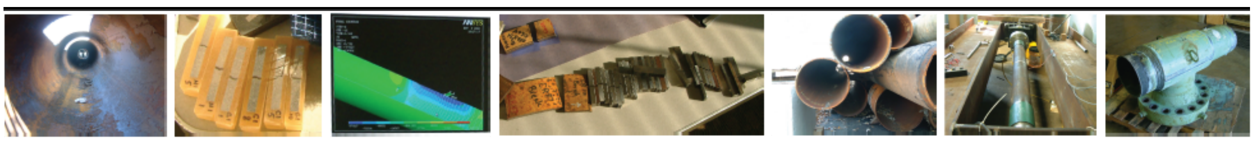
Final Report No. 10-094

Final Report

2009 Operational Reliability Assessment of the Longhorn Pipeline System

Harvey Haines, Carolyn Kolovich, and Dennis Johnston

December 17, 2010



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on

2009 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

December 17, 2010

by

Harvey Haines, Carolyn Kolovich, and Dennis Johnston

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TERMS, DEFINITIONS AND ACRONYMS

Many of the terms and definitions are taken directly from Section 2.0 of the ORA Process Manual titled Terms, Definitions, and Acronyms. Although all terms are highlighted in bold, definitions that are lifted directly from the ORAPM are also italicized.

1950 pipe material – pipe material laid in 1950. Although the majority of the Existing Pipeline is made up of 1950 pipe material, some consists of newer replacement pipe such as the 19 mile 2002 pipe replacement in the Austin area.

1998 pipe material – pipe material laid in 1998. Although the New Pipeline extensions consist almost entirely of 1998 pipe material some newer pipe material is contained in the existing 1950 pipeline in the form of pipe replacements.

Anomaly – A possible deviation from sound pipe material or weld. An indication may be generated by non-destructive testing, such as in-line inspection. [from NACE RP0102 In-Line Inspection of Pipelines]

AC – Alternating Current.

***API* –** American Petroleum Institute.

***ASME* –** American Society of Mechanical Engineers.

COM – Coordinator of Operations and Maintenance, Magellan personnel responsible for coordinating activities in the field along the pipeline ROW.

***CP* –** Cathodic Protection – A method of protection against galvanic corrosion of a buried or submerged pipeline through the application of protective electric currents.

d – defect depth.

***Defect* –** An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API Publication 570 – Piping Inspection Code. (Also see, anomaly).

***DOC* –** Depth of cover.

***DOT* –** Department of Transportation.

***EA* –** Environmental Assessment – An evaluation of the environmental, health and safety impacts of operating the proposed Longhorn Pipeline Project, including alternative proposals and mitigation measures. The US DOT/OPS and US EPA performed the EA as co-lead agencies.

***Encroachments* –** Unannounced or unauthorized entries of the pipeline right-of-way by persons operating farming, trenching, drilling, or other excavating equipment. Also, debris and other obstructions along the right-of-way that must periodically be removed to facilitate prompt access to the pipeline for routine or emergency repair activities. The Longhorn Pipeline System Integrity Plan (LPSIP) includes provisions for surveillance to prevent and minimize the effects of right-of-way encroachments.

EPA **–** Environmental Protection Agency.

EFW **–** Electric-flash weld is a type of EW using electric-induction to generate weld heat.

ERW **–** Electric-resistance weld is a type of EW using electric-resistance to generate weld heat.

EW **–** Electric welding is a process of forming a seam for electric-resistance (ERW) or electric-induction (EFW) welding wherein the edges to be welded are mechanically pressed together and the heat for welding is generated by the resistance to flow of the electric current. EW pipe has one longitudinal seam produced by the EW process.

Existing Pipeline – Originally defined in the EA, it consists of the portion of the pipeline originally constructed by Exxon in 1949-1950 that runs from Valve J-1 to Crane pump station. Currently the in-service portion of the Existing Pipeline runs from MP 9 to Crane because the 2 mile section from Valve J-1 to MP 9 is not in use.

GPS – global positioning system – a method for locating a point on the earth using the GPS.

HCA **–** High Consequence Area – as defined in 49 CFR 195.450, a location where a pipeline release might have a significant adverse effect on one or more of the following:

1) Commercially navigable waterway
2) High population area
3) Other populated area
4) Unusually sensitive area (USA)

HR **–** High Resolution (usually used to describe measurement resolution of ILI tools).

Hydrostatic Test – An integrity verification test that pressurizes the pipeline with water, also called a hydrotest or hydrostatic pressure test.

ILI **–** In-Line Inspection – the use of an electronically instrumented device that travels inside the pipeline to measure characteristics of the pipe wall and detect anomalies such as metal loss due to corrosion, dents, gouges and/or cracks depending upon the type of tool used.

ILI Final Report **–** A report provided by the ILI vendor that provides the operator with a comprehensive interpretation of the data from an ILI.

Incident – Incidents are events defined in the LMP to include accidents, near-miss cases, or repairs, and/or any combination thereof and are divided into three categories, Major Incidents, Significant Incidents, and Minor Incidents.

A “PHMSA (or DOT) reportable incident” is a failure in a pipeline system in which there is a release of product resulting in explosion or fire, volume exceeding 5 gallons (5 barrels from a pipeline maintenance activity), death of any person, personal injury necessitating hospitalization, or estimated property damage exceeding $50,000.

J-1 Valve – a main line pipeline valve in the Houston area, described in the LMP as the junction of the Existing Pipeline and a New Pipeline extension**.** Although this valve still exists, it is not contained in the currently active Longhorn pipeline, and the actual junction is at MP 9 (2 miles from the J-1 Valve).

L – defect length.

LMC – Longhorn Mitigation Commitment – Commitments made by Longhorn described in chapter 1 of the LMP.

***LMP* –** Longhorn Mitigation Plan – Commitments made by Longhorn to protect human health and the environment by conducting up front (prior to pipeline start-up) and ongoing activities regarding pipeline system enhancements and modifications, integrity management, operations and maintenance, and emergency response planning.

***LPSIP* –** Longhorn Pipeline System Integrity Plan – A program designed to gather unique physical attributes on the Longhorn Pipeline System, to identify and assess risks to the public and the environment, and to actively manage those risks through the implementation of identified Process Elements. Also chapter 3 of the LMP.

MASP – Maximum Allowable Surge Pressure

MIC – Microbiologically Influenced Corrosion – Localized corrosion resulting from the presence and activities of microorganisms, including bacteria and fungi.

MFL – Magnetic flux leakage – The flow of magnetic flux from a magnetized material, such as the steel wall of a pipe, into a medium with lower magnetic permeability, such as gas or liquid. Often used in reference to an ILI tool that makes MFL measurements.

mil – one thousandth of an inch (0.001 in).

MOCR – Management of Change Recommendation

MOP – Maximum Operating Pressure

MP – Mile Post.

NACE – NACE International formerly known as the National Association of Corrosion Engineers.

New Pipeline – In 1998 extensions were added to the Existing Pipeline to make the current Longhorn pipeline. Extensions were added from Galena Park to MP 9 and Crane to El Paso Terminal. Laterals were added from Crane to Odessa, and from El Paso Terminal to Diamond Junction.

OD **–** Outside nominal diameter of line pipe.

One-Call –Texas One-Call is a computerized notification center that establishes a communications link between those who dig underground (excavators) and those who operate underground facilities. The Texas Underground Facility Damage Prevention Act requires that excavators in Texas notify a one call notification center 48 hours prior to digging, so the location of an underground facility can be marked. The Texas One-Call System can be reached at toll free number 811 or website http://www.texasonecall.com/.

One-Call Violation – a violation of the requirements of the Texas Underground Facility Damage Prevention and Safety Act by an excavator. This ORA is concerned about violations within the Longhorn Pipeline ROW.

Operator – An entity or corporation responsible for day to day operation and maintenance of pipeline facilities.

OPS – Office of Pipeline Safety – co-lead agency who performed the EA, now a part of PHMSA.

ORA – Operational Reliability Assessment – Annual assessment activities to be performed on the Longhorn Pipeline System to determine its mechanical integrity and manage risk over time.

ORAPM – The ORA Process Manual.

PHMSA – The Pipeline and Hazardous Materials Safety Administration, the federal agency within DOT with safety jurisdiction over interstate pipelines.

POE **–** Probability of Exceedance – The likelihood that an event will be greater than a pre-determined level; used in the ORA to evaluate corrosion defect failure pressures versus intended operating pressures. The POE for depth (POE_D) is the probability that an anomaly is deeper than 80-percent of wall thickness. The POE for pressure (POE_P) is the probability that the burst pressure of the remaining wall thickness will be less that the system operating pressure or surge pressure. The POE for each pipe joint is POE_{joint}.

PPTS – API's Pipeline Performance Tracking System – a voluntary incident reporting database for liquid pipeline operators.

Process Elements **–** Items to be implemented as part of the LPSIP, including programs for corrosion management, in-line inspection, risk assessment and mitigation, damage prevention, encroachment, incident investigation, management of change, depth of cover, fatigue analysis, incorrect operations mitigation, and LPSIP performance metrics.

Recommendation **–** Suggestion for activities or changes in procedures that are intended to enhance integrity management systems, but are not specifically mandated in the LMP.

Requirement **–** Activities that must be performed to comply with the LMP commitments.

Risk **–** A measure of loss measured in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

Risk Assessment **–** A systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives.

Root Cause Analysis – Evaluation of the underlying cause(s) and contributing factors of a pipeline incident or damage requiring repair.

ROW **–** Right-of-way.

RPR – Rupture Pressure Ratio – for the Longhorn Pipeline System this is defined as the ratio of calculated Burst Pressure divided by the lesser of current MOP or MASP.

RSTRENG – A method of calculating the failure pressure (or Remaining STRENGth) of a pipeline caused by corrosion or metal-loss of the pipe steel. The method is capable of using an approximation of the defect profile rather than simpler two parameter methods that use simply the defect depth (d) and length (L).

SCC – *Stress Corrosion Cracking* – a form of environmental attack of the pipe steel involving an interaction of local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks. (ASME 31.8S)

Tier I Areas **–** Areas of normal cross-country pipeline.

Tier II Areas **–** Areas designated in the EA as environmentally sensitive due to population or environmental factors.

Tier III Areas **–** Areas designated as in the EA as environmentally hypersensitive due to the presence of high population, or other environmentally sensitive areas.

TFI – Transverse Field Inspection – an MFL Inspection tool with the field oriented in the circumferential direction. The tool differs from conventional MFL or HRMFL because these conventional tools have their field oriented in the axial direction or along the axis of the pipe.

TPD **–** Third-party damage.

TPD Annual Assessment – "Longhorn System Annual Third Party Damage Prevention Program Assessment" Report. The annual report written by the operator to summarize the TPD prevention program. This report is also known in the ORAPM process manual Appendix D as Item 71 Annual Third Party Damage Assessment Report

TRRC – Texas Railroad Commission, the agency with safety jurisdiction over Texas intrastate pipelines.

UT – ultrasonic testing **–** a non-destructive testing technique using ultrasonic waves.

wt – wall thickness of line pipe.

2009 Operational Reliability Assessment of the Longhorn Pipeline System

Harvey Haines, Carolyn Kolovich, and Dennis Johnston

1. INTRODUCTION

Objective

This report presents the annual assessment of the operational reliability of the Longhorn Pipeline System for the 2009 operating year. Kiefner and Associates, Inc. (KAI) has carried out the operational reliability assessment (ORA) which is intended to provide Magellan with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP), incorporate the results of all elements of the LPSIP as attributes and data to consider in the overall assessment of the mechanical condition of the Longhorn assets, and provide recommendations to preserve the long term integrity or mitigate areas of potential concern before they result in a breach of the pipeline system.

Background

In 1999 and 2000, prior to its commissioning, Longhorn Partners Pipeline, LP, the previous owner, participated in an Environmental Assessment (EA) that was prepared by the US Environmental Protection Agency (EPA) and Department of Transportation (DOT). The EA Finding of No Significant Impact was conditioned upon Longhorn's commitment to implement certain integrity-related activities and plans prior to pipeline start-up and periodically throughout the operation of the system. Longhorn's commitment to minimize the likelihood and consequences of product releases was specified in the Longhorn Mitigation Plan (LMP). These commitments include the Longhorn Continuing Integrity Commitment wherein Longhorn has agreed to implement System Integrity and Mitigation Commitments, and performance of annual ORAs. A list of the Longhorn Mitigation Commitments (LMC) covered by this ORA is provided in Appendix A. Magellan Pipeline Company, L.P. (Magellan) currently owns the Longhorn system assets; they purchased the pipeline in 2009, but have operated it since startup.

The LMP committed Longhorn to retain an independent third party technical company to perform the ORA, subject to the review and approval of the Pipeline and Hazardous Materials Safety Administration (PHMSA). Longhorn had selected and PHMSA approved KAI as the ORA contractor and Magellan is continuing with this agreement.

The LMP stipulates specific and general requirements of the ORA. Those requirements were extracted from the LMP and used to develop the Operational Reliability Assessment Process Manual (ORAPM). The ORA is carried out according to the ORAPM, revised as of August 25, 2004. Additional guidance for the ORA is provided by the “Mock ORA for Longhorn Pipeline” that was performed by KAI prior to commissioning of the pipeline. Among other things, the ORAPM requires the ORA contractor to provide periodic reports to Magellan and DOT/PHMSA.

The activities of the ORA contractor consist of assessing pipeline operating data and the results of integrity assessments, surveys, and inspections, and making appropriate recommendations with respect to seven potential threats to pipeline integrity. Managing these threats and preserving the integrity of the Longhorn system assets are among the goals of the LPSIP being carried out by Magellan. The seven threats are: pressure-cycle-induced fatigue, corrosion-caused metal loss, laminations and hydrogen blisters, earth movement from faults and water forces, third-party damage (TPD), stress-corrosion cracking (SCC), and malfunction or deterioration of facilities other than line pipe. The sixth of these threats, SCC, has not been identified as a threat of concern to the Longhorn pipeline, but was added as SCC has been an unexpected problem for some pipelines, even though these pipelines had not recognized SCC as a threat in the past.

ORA Interaction with the LPSIP

The LPSIP is the direct operator interface with the daily operations and maintenance of the Longhorn system assets. It contains twelve process elements that are used to formulate prevention and mitigation recommendations that are directly implemented on a periodic basis throughout pipeline operations. The LPSIP serves as the primary mechanism for the generation and collection of pipeline system operation and inspection data that are required for performance of ORA functions. Integrity intervention and inspection recommendations resulting from the ORA analyses are implemented by the LPSIP.

The twelve elements of the LPSIP are:

- Corrosion Management Plan
- In-Line Inspection and Rehabilitation Program
- Key Risk Areas Identification and Assessment
- Damage Prevention Program
- Encroachment Procedures
- Incident Investigation Program
- Management of Change
- Depth of Cover Program

- Fatigue Analysis & Monitoring Program
- Scenario Based Risk Mitigation Analysis
- Incorrect Operations Mitigation
- System Integrity Plan Scorecarding and Performance Metrics Plan

Longhorn Pipeline System Description

The Longhorn Pipeline is comprised of 18 and 20-inch diameter pipe, which extends 694 miles from Galena Park, Texas to a terminal located 3 miles east of El Paso, Texas, plus an 8-inch lateral which extends 29 miles from Crane to Odessa, Texas, and 4 laterals which extend 8.5 miles from El Paso Terminal to Diamond Junction. The pipeline delivers refined petroleum products (gasoline and other motor fuels) to markets in El Paso and Odessa with connections through other pipelines at Diamond Junction to New Mexico and Arizona. Approximately 449 miles of this pipeline were constructed in 1950. This portion of the pipeline was formerly operated by Exxon Pipeline Company to transport crude oil from Crane, Texas to Baytown, Texas. The existing crude-oil system was idled in 1995. It was subsequently reconditioned, including a 2002 replacement of approximately 19 miles in the Austin area, and converted to refined products service. Two hundred forty six (246) miles of new line pipe were installed in 1998 to extend the pipeline to its present route. Approximately 9 miles of new pipe were installed from Galena Park to MP 9, and 237 miles of new pipe were installed from Crane to El Paso, Texas. The laterals to Crane and Diamond Junction were installed in 1998.

The original 1950 Exxon pipeline is described in the EA as the Existing Pipeline to differentiate it from the New Pipeline extensions installed in 1998. The currently operating pipeline does not include the J-1 Valve because the 9 mile extension from Galena Park to MP 9 was connected with the Existing Pipeline approximately 2 miles downstream of the J-1 Valve. In addition, there is also no pig launcher at this junction at MP 9, so effectively when commitments for the Existing Pipeline (Valve J-1 to Crane) are performed, they are required on the active Existing Pipeline (MP 9 to Crane) and performed from Galena Park (MP 0) to Crane (MP 457.5).

Time Scope

This report presents the annual assessment for 2009 of the operational reliability of the Longhorn system assets. The pipeline entered commercial refined product service on January 27, 2005. The first ORA Annual Report was prepared for the period from January 27, 2005 through January 26, 2006. Subsequent annual reports cover the calendar year, aligning the report period with annual reports prepared for the Longhorn pipeline, many of which are used to prepare this ORA annual report. In addition this reporting period and ORA Report submission date complies with the requirements in LMC 38 of the LMP and Section 13 of the ORAPM.

2. EXECUTIVE SUMMARY

This 2009 annual ORA report of the Longhorn system assets addresses the following subjects:

- Threats and Potential Threats to the Pipeline
    - Pressure-Cycle-Induced Fatigue
    - Corrosion
    - Laminations and Hydrogen Blisters
    - Earth Movement and Water Forces
    - Third-Party Damage
    - Stress-Corrosion Cracking
    - Threats to Facilities Other than Line Pipe
- Technical Assessment of the effectiveness of the LPSIP

The analyses of operational pressure cycles to date show that the intensity of pressure cycles is relatively nonaggressive in relation to benchmarks established on the basis of typical liquid petroleum products and crude oil pipelines. If this continues to be the mode of operation, integrity reassessment from the standpoint of electric-resistance weld (ERW) seam anomalies will not be necessary until the year 2040. A TFI tool run, completed in 2007 and early 2008, is used to define a flaw size that will determine the reassessment interval. Seventy five (75) seam weld features were identified and remediated during the 2007 and 2008 program. Therefore, the reassessment interval uses the seam weld feature detection threshold value from the TFI tool vendor.

Corrosion is a time dependent threat that is continually monitored using ILI, annual corrosion surveys, and close interval surveys. Ultrasonic (UT) wall measurement tools have been run from Galena Park to Crane and were completed in 2010. The UT data will be used in conjunction with the previous MFL metal loss tools to assess corrosion growth on the pipeline. These activities will occur in 2010, as the UT data are available. In addition, excavations were completed in 2009 on the Crane to Cottonwood, the Cottonwood to El Paso, and the Cedar Valley to Eckert segments completing the ILI remediation required on the new pipeline extension between Crane and El Paso.

The condition of any laminations and blisters that may still exist in the 1950 pipe material will be evaluated using the UT tool results. Although LMC 12 required this inspection to be completed by January 26, 2010, a delay was encountered because of slow throughput and the need for extensive cleaning to run a UT ILI tool. The final reports from the ILI vendor are expected in 2010, these results and results from excavations will be reported in future ORA annual reports.

From the standpoint of earth movement, the primary integrity concerns are soil erosion and scouring from floods and the ground movement from aseismic faults at specific points along the pipeline. Scour surveys on the Colorado River and its tributary Pin Oak Creek show little to no evidence of soil erosion or scouring. No other river crossing inspections were required in 2009, but should be reinspected in 2010 as part of their 5-year reinspection requirement. As of 2009, 5 years of data of aseismic fault movements have been taken. The results show fault movement on three of the faults to be so small that ground movement will not be a threat over the potential life of the pipeline and the fourth fault at the Hockley site is only a minor threat.

The Longhorn third-party damage (TPD) prevention program far exceeds the minimum requirements of federal or Texas state pipeline safety regulations, and it represents a model program for the industry. The aerial surveillance and ground patrol frequencies exceeded the frequencies set forth in the LMP. In our opinion, the damage prevention program is a major contributing reason why no hits occurred on the pipeline in 2009 in spite of the fact that 13,242 One-Call notifications were received by the operator of the pipeline.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. In accordance with the ORAPM, Longhorn performed investigative digs each year for the three years from 2005-2007 in areas potentially susceptible to SCC. No SCC was found. Magellan continues to carry out checks as part of the normal dig program by performing an SCC examination program using magnetic particle testing at each dig site.

From the standpoint of facilities data acquired in 2009, one can conclude that pump station and terminal facilities had no adverse impact on public safety. Only one small non-reportable release of product occurred which was contained onsite so there was no risk to public safety.

The technical assessment of the LPSIP indicates that Magellan is achieving the goal of the LPSIP, namely, to prevent incidents that would threaten human health or safety or cause environmental harm. In terms of activity measures, Magellan exceeded the goals of aerial surveillance and ground patrol frequency. In addition, public-awareness meetings were held, an equipment rental/farm store public education program was conducted, and right-of-way markers and signs were repaired or replaced. From the standpoint of deterioration measures, a small number of metal-loss and seam anomalies were discovered and repaired. In terms of failure measures, there were no DOT-reportable incidents and there were no known third-party hits.

3. RECOMMENDATIONS

3.1 Technical Assessment of LPSIP Effectiveness

The LPSIP contains twelve process elements. Seven of these elements are listed below along with an assessment of their effectiveness. These elements are most closely related to the threats addressed by the ORAPM and are summarized in detail with recommendations. The assessments for the remaining five elements can be found in the Annual LPSIP Self-Audit Report for Longhorn Pipeline System.

Longhorn Corrosion Management Plan

The corrosion management plan has been effective at preventing corrosion degradation in 2009. The pipe replacement between Crane and Cottonwood successfully eliminated the most severe corrosion as measured by the MFL tools run in 2008. Internal corrosion coupon results show little to no corrosion.

Magellan completed an AC mitigation study in 2009 for the 9 mile extension between Galena Park and MP 9. These results should be considered in conjunction with the results obtained from the September 2009 UT ILI run. The September 2009 UT ILI data indicated no new corrosion, therefore the AC mitigation is considered to have been effective.

In-Line-Inspection and Rehabilitation Program

Magellan had attempted to perform the ILI inspection to address the commitment to LMC 12, the requirement to conduct a UT ILI of the existing pipeline (Valve J-1 to Crane), by the January 26, 2010 deadline. Because of throughput limitations they were unable to meet the deadline for three of the six ILI segments. An analysis outlined in a February 17, 2010 KAI Letter Report determined there was minimal risk for an additional delay. The three segments were inspected by August 5, 2010. Other than this delay, Magellan continues to meet its ILI commitments and the program has been effective at fulfilling the integrity requirements in the LMP.

Damage Prevention Program

The absence of reportable incidents involving mainline pipe and the absence of third party contact with the pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended. After missing some periods in 2008 because of weather, Magellan implemented better procedures to ensure ground patrols are performed when the aerial patrols are not possible.

Since the implementation of better procedures Magellan has been able to meet its 72-hour commitment.

Encroachment Procedures

There were 67 encroachments recorded in 2009 of which 3 were unauthorized. The program's encroachment agreements have been effective at keeping authorized encroachments from damaging the pipeline. This is demonstrated because none of the authorized encroachments resulted in contact with the pipeline, while each of the three unauthorized encroachments did result in a near miss. In addition, the absence of reportable incidents involving mainline pipe and the absence of third party damage also support that the program has been effective.

Incident Investigation Program

Magellan is performing incident investigations on all DOT reportable incidents and on many more non-reportable incidents. Incident investigations were reviewed on all near-misses as recommended in last year's ORA. KAI finds these incident investigations sufficient. In addition, Magellan should be commended for having no DOT reportable incidents on the Longhorn pipeline in 2009.

Depth of Cover Program

A Depth of Cover (DOC) survey has not been performed since the 2007 survey. 2009 focused on preventing removal of cover by road graders where unpaved roads cross the Longhorn ROW. We find this program effective at identifying shallow pipe that may increase the threat of outside force damage.

Fatigue Analysis and Monitoring Program

The 2009 fatigue analysis performed by KAI incorporated results from the 2007-2008 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. The analysis for this program is covered under Section 5.1 of this report.

3.2 Recommended Intervention Measures and Timing

Pressure-Cycle-Induced Fatigue

For the threat of pressure-cycle-induced fatigue, a reassessment in the year 2040 was calculated based on the pressure cycles for 2008 through 2009 and using the results from the 2007-2008 TFI tool runs.

Corrosion

For the threat of corrosion, no new reassessments were performed for the Existing Pipeline. MFL inspections were evaluated between Crane and El Paso. UT inspections for the Existing Pipeline will be used to reassess the interval in 2010 and determine corrosion rates based on the UT ILI runs and the earlier MFL ILI runs.

Laminations and Hydrogen Blisters

The UT tool inspection initiated in 2009 should confirm whether any blisters remain in the pipeline and allow the operator of the pipeline to remediate any remaining injurious blisters.

Earth Movement and Water Forces

The earth-movement analysis from data collected from 2004-2009 shows movement that is an order of magnitude less than the assumptions used to justify the required monitoring program in the EA. The measurements at three of the faults show no probability of failure within the lifetime of the pipeline. Measurements across the fourth fault should continue, but at a reduced inspection rate. Because there is a possibility of fault movement re-initiating, some monitoring of the three faults is warranted, but also at an increased time between measurements. KAI recommends five years between measurements which is the same time frame for other monitoring measurements on the pipeline such as ILI and ground movement patrols. If the faults appear to become more active, then more frequent measurements can be implemented.

Inspections showed no signs of erosion or scour damage at stream crossings from storm water flooding. Stream crossing monitoring should continue every five years and after storm events for identified stream crossings. The scour inspection for the Colorado River and Pin Oak Creek should continue biannually and after every second standard flood as specified by studies referenced in LMC 19.

Third-Party Damage

For the threat of TPD, Magellan should continue both prevention and inspection activities. Prevention activities include ROW surveillance and public-awareness activities that continued to be successful in 2009. Inspection activities include almost all ILI inspections required as part of the ORA, including the MFL-geometry inspection carried out in 2004-2007, the TFI-geometry inspection in 2007-2008, and the UT-geometry inspection initiated in 2009. LMC 12A requires inspections with a “smart” geometry tool be carried out within three years of a previous inspection. These inspections are occurring more frequently because they also fulfill other Longhorn Mitigation Commitments. For specific inspection dates (to fulfill the requirement for each of the six intervals spanning the Existing Pipeline from Galena Park to Crane) see Table 9 in Section 7 on Integration of Intervention Requirements.

Stress-Corrosion Cracking

As no evidence of SCC has been detected, it is not necessary to recommend an intervention measure. Magellan should continue to monitor for this threat through their current method, which consists of looking for evidence of SCC when maintenance excavations are performed.

Threats to Facilities Other than Line Pipe

Magellan should continue to carry out inspections and maintenance of facilities with the same diligence and frequency as performed in 2009.

3.3 Implementation of New Mechanical Integrity Technologies

No new technologies were implemented in 2009.

3.4 ORA Process Improvements

Magellan should continue to use RSTRENG or other equivalent effective area methods for failure pressures calculations when using the POE process.

4. NEW DATA USED IN THIS ANALYSIS

The ORA Process Manual identifies 78 items consisting of data, data logs, and reports the ORA contractor must review and consider in conducting the ORA. A list of these 78 items is contained in Appendix D of the ORAPM and discussed in Appendix B of this report.

5. RESULTS AND DISCUSSION OF DATA ANALYSIS

This section presents an analysis of the data collected in Section 4 for the seven ongoing integrity threats monitored by the LMP: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, earth movement, third-party damage (TPD), stress-corrosion cracking (SCC), and threats to facilities other than line pipe.

5.1 Pressure-Cycle-Induced Fatigue Cracking

Pressure-cycle-induced fatigue-crack-growth of defects is recognized to be a potential threat to the integrity of the Longhorn Pipeline. Manufacturing defects in or immediately adjacent to the longitudinal ERW or EFW seams of the 1950 line-pipe material contained in the Existing Pipeline are considered to be the primary concern. The concern is that a defect that initially may be too small to fail at the operating pressure will grow through fatigue cracking and become large enough to cause a failure if exposed to sufficient numbers of large pressure fluctuations. Accordingly, Section 3 of the ORAPM requires the monitoring of pressure cycles during the operation of the pipeline, calculating the worst-case crack growth in response to such cycles, and reassessing the integrity of the pipeline at appropriate intervals to find and eliminate growing cracks before they become large enough to cause a failure of the pipeline. Although the likelihood of such defects being present in the newer 1998 pipe material is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses are performed for the New Pipeline extensions (Galena Park to MP 9 and Crane to El Paso) as well as for the Existing Pipeline (MP 9 to Crane).

The potential effects of pressure-cycle-induced fatigue are calculated for the Existing Pipeline on the basis of the results of the TFI tool run from Galena Park to Crane completed in 2007 and early 2008.

The failure pressure of each defect is controlled not only by its size, but by the diameter and wall thickness of the pipe, the strength of the pipe, and the toughness of the pipe. Toughness is the ability of the material containing a given-size crack to resist tearing at a particular value of applied tensile stress. Toughness in line-pipe materials has been found to correspond reasonably well to the value of “upper-shelf” energy as determined by means of standard Charpy V-notch impact tests. As noted in Reference[1,] the Charpy V-notch energy levels for samples of the 1950 material ranged from 15 to 26 ft-lb. To conduct a pressure-cycle analysis for the Longhorn Pipeline, we use the well-known and widely accepted “Paris Law” model in which the natural log of crack growth per cycle of pressure (or hoop stress) is assumed to be proportional to the natural log of the change in stress intensity represented by the pressure change. The slope and intercept of this relationship are constants that depend on the nature of the material and the environment in which the crack exists. In the absence of empirical data for the particular crack-growth environment of the Longhorn Pipeline, we use values for the constants that have been established through large numbers of laboratory tests and that are published in the Fitness-For-Service API Standard 579-1/ASME FFS-1. The change in stress-intensity factor corresponding to a change in pressure is calculated via a Raju/Newman algorithm. Details of these equations are available in the Mock ORA (Reference 2 or in Reference 3, a readily available technical publication).

Pressure-cycle data are provided to us by the operator of the Longhorn Pipeline. We use a systematic cycle-counting procedure called "rainflow counting" to pair maximum and minimum pressures. The rainflow-counted cycles are used in the Paris-law model to grow a potential crack. For a given set of cycles, we can predict the number of such cycles (and the length of time) that it will take for the fastest growing defect to reach a size that will fail at the maximum operating pressure of the pipeline. We make Magellan aware of that time, and in accord with the LMP, Magellan will carry out a reassessment of the integrity of the pipeline before 45 percent of the time to failure has expired.

The line pipe that is expected to be the most susceptible to longitudinal-seam fatigue-crack-growth is the 1950 pipe material which includes the 20-inch OD, 0.312-inch WT Grade B pipe, the 18-inch OD, 0.281-inch and 0.312-inch WT X45 pipe, and the 18-inch OD, 0.250-inch WT X52 pipe. The results of the TFI tool run indicated the presence of 75 Seam Weld A and B features in the Galena Park to Crane segment, or those that are presumed to be crack-like in nature. Through the course of the 2007 and 2008 dig program, each of the crack-like indications called out by the tool have been repaired. Therefore, the procedure in Section 3.4 of the ORA Process Manual requires the use of detection threshold capabilities of the TFI tool to determine an appropriate reassessment interval. The TFI detection capabilities for seam weld features state that a depth of 50-percent of the wall thickness for features between one and two inches in length and a minimum depth of 25-percent of the wall thickness for features greater than two inches in length could be missed.

Based on these detection capabilities, the analysis assumes that a 50-percent through wall, 2-inch long crack-like feature could have been missed. The 50-percent through wall defect has a shorter life than a 25-percent through wall defect. In the Existing Pipe, we assume the defect could have been missed in a location that will provide the most conservative reassessment interval. We chose the pipe located closest to the discharge of a pump or right at a wall thickness or pipe grade transition to capture the strongest effects of the pressure cycles. It is not necessary to calculate a fatigue life at all the points where the susceptible pipe exists because pipe further downstream will have a longer fatigue life based on the hydraulic gradient and need not be evaluated.

A slightly different procedure is applied to the calculation of time to failure for the newly installed pipe. Instead of using the sizes of defects detected by the TFI tool, we use a starting defect size that is the largest defect that could have escaped detection in the manufacturer's ultrasonic seam inspection. That would be the size of the "calibration" defect used to test the ultrasonic seam inspection detection threshold. That size comes from API Specification 5L, and it is assumed by us to be the largest of the acceptable calibration defects in that standard, namely, the N10 notch. The N10 notch has an axial length of two inches, and a depth of 10 percent of the nominal wall thickness of the pipe. That defect is used as the starting defect size in our analysis. Otherwise the analysis procedure for determining the reassessment time for the 1998 pipe material is the same as that described above for the 1950 pipe material.

Prior to completing the TFI tool run, the ORAPM specified a process that used the previous hydrostatic test pressure levels to determine a starting defect size. In this case, toughness is a factor for establishing starting defect sizes and it is more conservative to use a higher value of toughness as it allows for a larger defect to remain after the hydrotest. Note that toughness is not a factor in establishing either starting defect size using the ILI detection threshold or the N10 notch. However, toughness is needed to calculate the size of the defect that will cause failure at the operating pressure. In these cases, a lower toughness value generally leads to more conservative calculated fatigue lives. However, for the specific flaw sizes used in our analysis, the fatigue life does not change whether 15 ft lbs or 25 ft lbs is assumed. This is due in part to the relatively short length of the starting defects. With a longer defect, it would be expected that using a value of 15 ft lbs instead of 25 ft lbs would decrease the fatigue life. We have used a value of 15 ft lbs in our calculations.

Our analysis shows that the shortest time to failure for a possible feature that could have been missed by the TFI tool is 73.9 years at the Kimble County Discharge. The recommended reassessment interval is calculated by taking 45 percent of the shortest fatigue life, which corresponds to a factor of safety of 2.22 (1/0.45). Applying this factor of safety, we recommend a reassessment interval of 33.2 years based on the current operating pressures. An assessment would be required in early 2040 as this pipe was inspected in 2007. Again as stated above, the predicted time to failure using Paris Law is based on the crack growth rate given in the Fitness-For-Service API Standard 579-1/ASME FFS-1 for weld-metal material.

A fatigue life was also calculated for the new 1998 pipe material at Galena Park Station, and Crane Station based on the maximum flaw size that could exist as stated by the manufacturer.

This flaw is described above as an API 5L N10 notch, a 10-percent, 2-inch-long flaw, and was used to calculate the fatigue life at these locations. Table 1 summarizes the locations evaluated.

Table 1. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations

	Description	**Station**	**Mile Post**	**Diameter, inches**	**Wall Thickness, inch**	**Pipe Grade**
Case 1	1998 ERW pipe at Galena Park	0+00	0	20	0.312	X52
Case 2	Transition to 1950 ERW pipe at MP9 downstream of Galena Park	480+09	9.1	20	0.312	Grade B
Case 3	Transition to heavy wall 1950 EFW pipe	1067+46	20.2	20	0.375	Grade B
Case 4	1950 EFW pipe at Satsuma	1802+61	34.1	18	0.281	X45
Case 5	Transition to heavy wall 1950 EFW pipe	1821+42	34.5	18	0.375	Grade B
Case 6	1950 EFW pipe downstream of Cedar Valley	10037+72	190.1	18	0.312	X45
Case 7	1950 EFW pipe at Kimble County	15589+07	295.2	18	0.281	X45
Case 8	Transition to 1950 ERW pipe at Kemper (former Exxon Station)	21387+88	405.1	18	0.25	X52
Case 9	1998 ERW pipe at Crane	24158+39	457.5	18	0.281	X65

Table 2 below depicts the fatigue life for each of the above locations. The reassessment interval is based on the remediation of all cracks detectable by the TFI, a high probability of detection for TFI finding all features greater than 50-percent deep and two inches long, and the factor of safety of 2.22.

Table 2. Fatigue Lives for the Pressure-Cycle Analysis Locations

	Time to Failure for a Defect That May Be Present, Years	Recommended Reassessment Interval (Includes Safety Factor of 2.2)	Year of ILI Tool Run/Installation	Recommended Year of Next Assessment
Case 1	> 500	> 225	2000	> 2225
Case 2	347.8	156.7	2007	2163.7
Case 3	> 500	> 225	2007	> 2232
Case 4	91.9	41.4	2007	2048.4
Case 5	287.8	129.6	2007	2136.6
Case 6	127.3	57.3	2007	2064.3
Case 7	***73.9***	***33.3***	***2007***	***2040.3***
Case 8	397.7	179.1	2008	2187.1
Case 9	> 500	> 225	1998	> 2223

5.2 Corrosion

Corrosion Control

The LMP describes an extensive Corrosion Management Plan to control the extent to which corrosion can occur within the system. KAI has received inspection reports for Pipe to Soil Potential Surveys, Rectifier Inspection Surveys and Foreign Line Crossing Surveys for 2009. Corrosion coupon surveys for monitoring the internal corrosion showed little to no corrosion with measured weight loss corrosion rates much less than 1 mil/year.

In addition, an AC mitigation study was completed for the first nine miles downstream of Galena Park where the pipeline shares a corridor with multiple overhead high voltage electric transmission lines. The report recommended reducing the AC voltage to the 5-10 Volt range to minimize the possibility of AC corrosion in the corridor. Subsequent AC potential surveys showed potentials as high as 14 Volts. Comparing the AC potentials to any new corrosion that may have occurred on the pipeline detected from the recent UT ILI runs indicate the AC corrosion threat is being managed even with higher than recommended AC potentials. At this time we do not see a need to implement the AC study recommendations, but if additional corrosion becomes apparent from future ILI runs then the AC studies may need to be reinitiated.

Monitoring the Possibility of Corrosion-Related Leaks or Ruptures using ILI

ILI results are commonly used by pipeline operators as a means for identifying and evaluating corrosion-caused metal loss and planning remediation. This typically involves running an ILI tool to identify, size, and as necessary excavate corrosion features that exceed a depth or a pressure threshold. This generally accepted method is a valid approach for addressing line pipe corrosion.

TFI Inspection

LMC 10 required Magellan to inspect the Existing Pipeline with a reliable crack tool. A transverse field (TFI) magnetic flux tool was selected for this assessment. The TFI tool can also be used as a corrosion assessment tool particularly for detection of longitudinally oriented corrosion or preferential longitudinal seam corrosion. During 2009, four metal-loss seam weld anomalies were addressed on the Cedar Valley to Eckert segment. Each of these anomalies was excavated, evaluated, and remediated. A more detailed anomaly listing is available in section 4.3 of Appendix A.

HRMFL Inspections

A HRMFL-deformation combination ILI tool was run in the Crane to Cottonwood and the Cottonwood to El Paso segments.

<u>Crane to Cottonwood – HRMFL Analysis</u>
The Crane to Cottonwood metal loss inspection was completed November 21, 2008. A number of internal metal loss anomalies were predicted. An effective area remaining strength process (RSTRNG) was utilized on the metal loss anomalies for POE calculations. Sixteen dig locations were excavated and evaluated during 2009. The dig locations included one dent anomaly, five external metal loss anomalies, and twenty-seven internal metal loss anomalies.

<u>Cottonwood to El Paso – HRMFL Analysis</u>
An HRMFL ILI tool was run on the Cottonwood to El Paso section on March 27, 2008. A number of internal metal loss anomalies were predicted. An effective area remaining strength process (RSTRNG) was utilized on the metal loss anomalies for POE calculations. Two internal metal loss anomaly locations were excavated and evaluated during 2009. These two dig locations included a total of five internal metal loss anomalies.

Corrosion Growth Analysis

Section 4.7 of the ORA Process Manual describes the procedure for determining corrosion growth rates between successive HR ILI tool runs. The UT tool results that will be available in 2010 should provide metal loss data (in addition to lamination and hydrogen blister data) that could be compared to the HRMFL metal loss data to roughly estimate corrosion rates. In addition, Magellan implemented two UT monitoring stations between Crane and Cottonwood in February 2010 to monitor corrosion growth.

5.3 Pipe Laminations and Hydrogen Blistering

LMC 12 of the Longhorn Mitigation Plan calls for a UT ILI of the pipeline from Valve J-1 to Crane Station within 5 years of system startup. The UT ILI tool is the inspection tool of choice for the identification of laminations. Ultrasonic wall measurement data in combination with a high-resolution geometry tool are the tools of choice for the identification of hydrogen blisters. The UT ILI tool runs are complete and the results will be received and remediated in 2010.

5.4 Earth Movement (Fault and Stream Crossings)

Fault Crossings

The Longhorn pipeline system crosses several aseismic faults between Harris County and El Paso, Texas. None of the faults west of Harris County are known to be active. Within Harris County, the pipeline crosses four aseismic faults that are considered to be active. The location and geologic data concerning these faults are summarized in Table 3.

Table 3. Fault Location and Geologic Data for the Active Aseismic Faults in Harris County, Texas

	Location			Fault				Soil	
Fault	MP	Station	± feet	Orientation	Dip	Displacement	Width (ft)	Classification	Formation
Akron	3.84	202+90	60	N85E		down N		CL	
Melde	5.66	298+60	50	N64E		down N		CL	Beaumont
Breen	25.85	1364+85	50	N50E		down NW	13	CL	Lissie
Hockley	46.34	2446+60	70	N56W	67SW		80	CL	Lissie

Monitoring stations across the faults were installed in March 2004 in accordance with section 6.2 of the ORAPM. Baseline readings were taken in late May and early June 2004. Eight subsequent displacement readings have been taken at approximately 6 month intervals. A plot of the displacements over time is shown in Figure 1 below. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. With 5½ years of data we attempted to measure the actual fault movement over time by calculating best fit trend lines. The trend lines show no measureable movement on the Melde and Breen faults, with only slight movement of 0.06 in (1.5 mm) over 5½ years for the Akron fault and -0.08 in (-2 mm) over 5½ years for the Hockley fault.

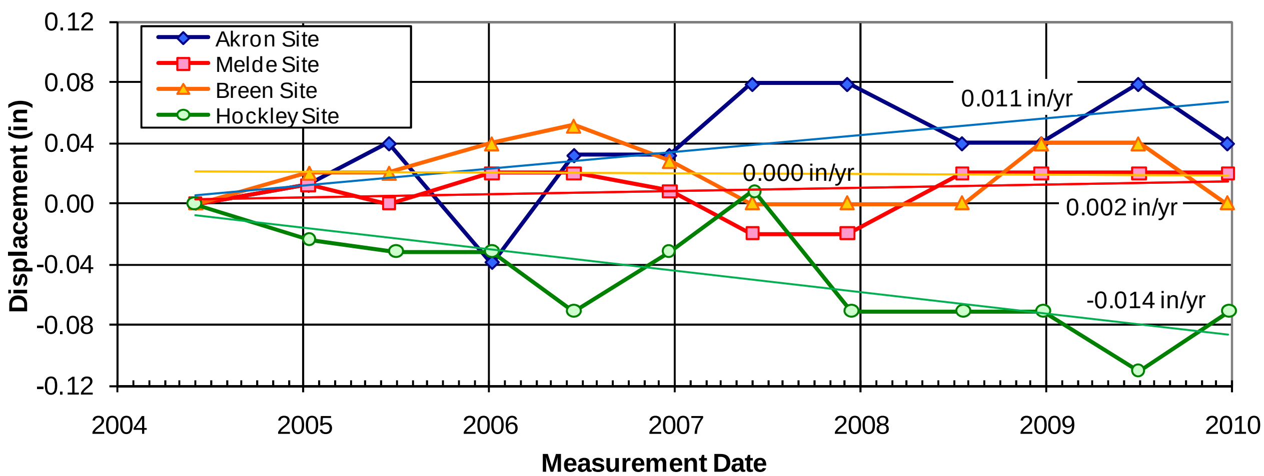

Figure 1. Fault Displacement Over 5½ Year Period

In previous years where we used the apparent measurement accuracy for each individual measurement of ±1 mm to calculate a minimum estimate of the time to reach the ASME B31.4 stress criteria. For this year's analysis with 5½ years of data, we used the calculated movement from the best fit trend lines and compared these estimates of fault growth to the KAI stress analysis described in the 2005 ORA Annual Report. Table 4 shows the amount of movement at each fault that can occur before it exceeds the stress levels allowed by ASME B31.4. The differences in allowable fault displacements are caused in large part by differences in the angle of the fault movement.

Table 4. Summary of Estimated Allowable Fault Displacement Due to Stresses

	Displacement (in)	Years to Reach Displacement
Akron	4.17	380
Melde	4.13	> 1000
Breen	1.50	> 1000
Hockley	0.63	45

Assumptions used in the analysis included: the stress in the Longhorn Pipeline is below the allowable stress levels of ASME B31.4 at this time; the initial stress in the pipeline is given by ASME B31.4 stress analysis; the soil properties are our best estimate for representative values of properties we could obtain; the fault movement can be represented by linear trend lines fit to the data. On the basis of these assumptions, the analysis in Table 4 shows the amount of time it will take for stress levels to exceed those allowed by ASME B31.4.

In past years we have agreed with earlier GeoSyntec Consultants recommendations to increase reassessment intervals from six months to one year. However even this recommendation appears conservative using the estimates of fault growth rate; as a result, a reinspection interval of every five years appears sufficient for the Hockley fault. Even though the time to failure is several times the life of the pipeline for the other three faults, according to the U.S. Geological Survey, September 2005[4] there are documented cases of fault movement reinitiating, so minimal monitoring every five years is appropriate.

In reviewing some of the original assumptions in the aseismic fault analysis, Section 6.4 on Aseismic Faulting/Subsidence Hazards of Appendix 9E of the Environmental Assessment[5] estimated the rates of vertical movement on the order of 0.2 inch per year based on field observations. Actual measurements over the past 5½ years show rates are more than an order of magnitude less than estimates from the EA. Thus one of the original reasons for monitoring these four faults was overly conservative in its estimation of fault movement rates.

Stream Crossings

There are many stream crossings on the Longhorn system, with all but two needing inspections once every 5 years according to section 6.3 of the ORAPM. The two streams which require biannual inspections, the Colorado River and its tributary Pin Oak Creek, were inspected June 6 and December 28 in 2009, respectively. Results show some small changes in the toes on the banks of the Colorado River, but do not indicate any significant scouring. The other crossings were last inspected in 2005 and require reinspection in 2010.

5.5 Third-Party Damage

Section 7 of the ORAPM divides the assessment of TPD prevention into three parts: data review, One-Call violation analysis, and intervention recommendations.

Data Reviewed

The data reviewed included:

- Item 50, Right-of-Way (ROW) Surveillance Data
- Item 51, Third-Party Damage, Near Misses
- Item 52, Unauthorized ROW Encroachments
- Item 53, TPD Reports on Detected One-Call Violations
- Item 56, Miles of Pipe Inspected by Aerial Survey by Month
- Item 57, Number of Pipeline Signs Installed, Repaired, Replaced by Month
- Item 58, Number of Public Outreach or Educational Meetings
- Item 59, Number of One-Calls by Month by Tier
- Item 60, Public Education and Third-Party Damage Prevention Ads Quarterly
- Item 61, Number of Website Visits to Safety Page by Month
- Item 67, Number of ROW Encroachments by Month
- Item 68, Number of Hits by Month
- Item 71, Annual Third-Party Damage Assessment Report (TPD Annual Assessment)
- Item 72, One-Call Activity Report
- Item 77, Results of ILI for TPD

From the data listed above including an analysis of the 2009 TPD Annual Assessment we conclude:

- There were 6 near misses reported.
- Of the 6 near misses 3 were documented and verified unauthorized ROW encroachments.

- No documented physical hits to the pipeline occurred in 2009, the same as in 2008, 2007 and 2006.
- There were 4 One-Call violations reported in 2009, up from 3 in 2008, up from 3 in 2007, up from 0 One-Call violations in 2006, and down from 7 One-Call violations in 2005.
- The TPD Annual Assessment shows a 13-percent decline of unique aerial patrol observations, with activity related to an 8-percent drop in third-party activity or non-company observations.
- Total One-Call tickets as tabulated in the 2009 TPD Annual Assessment are 13½-percent lower than the total from 2008.

For further detail see Appendix B, Section 4.11 One-Call Violations and Third-Party Damage Prevention Data Right-of-Way Surveillance Data.

A Depth of Cover (DOC) Survey was conducted in 2007 and the results were reported in the 2008 TPD Annual Assessment. One 2009 incident investigation at Chico Lane in Big Lake discussed the continuing removal of cover (15 inches remaining in 1999, 9 inches remaining from the DOC survey in 2007, 5 inches remaining in 2008 from Wallace report, and 4 to 5 remaining inches in 2009 as verified by a Magellan Coordinator of Operations and Maintenance (COM). The removal of cover is caused by road widening, water erosion, road grading, and increased heavy equipment use. Road signs were added to the pipeline crossing instructing road graders to raise their blade in addition to constructing a concrete cap over the entire road crossing in the right-of-way.

The TFI and HRMFL surveys results were examined for potential third party damage. ILI and maintenance reports documented eight dents on top of pipe with depth greater than 2-percent of the diameter that were excavated, evaluated, and repaired. The ILI tool indicated metal loss at one of these locations. From direct examination, none of these anomalies were found to contain gouges. Therefore none of the eight dents was considered to be mechanical damage.

One-Call Violation Analysis

Out of 13,242 One-Calls in 2009, it appears that 7.0-percent required field locates and were potential ROW encroachments. The operator of the pipeline is effectively screening the One-Calls to separate, on the basis of the location, information associated with each “ticket” (industry jargon for a One-Call notification), and the likely encroachments from the “no locates” (industry jargon for a One-Call location that is sufficiently remote from the ROW to assure that no effort is needed to mark the location of the pipeline).

Most One-Call tickets continue to occur in three counties. Harris County accounted for 9,021 (68-percent) of the One-Call tickets. Travis County accounted for 1,761 (13-percent) of the One-Call tickets. Thus, fully 81-percent of the One-Call notifications on the pipeline occurred in these large metropolitan areas. Clearly, based upon that data, these two areas present the greatest potential for third-party damage. Bastrop County was a distant third with 303 tickets (2.3-percent). Given that there were no known hits on the pipeline, one could reasonably conclude the One-Call system and Magellan's surveillance plans are working well.

Figure 2 below shows an analysis of the One-Calls. Out of 13,242 One-Calls only 1 resulted in a near miss to the pipeline. This near-miss was the result of incorrect operations of the third-party who made the One-Call. A line locator discovered an electric power pole installed in the ROW in conflict to the location established during a previous meeting with the power pole installation contractor. In addition, there were five other cases where a third-party should have used One-Call to notify Magellan of activity in the ROW resulting in a total of six near misses.

Of the six near misses, the TPD Annual Assessment reported four One-Call violations, three in which the excavator did not use the One-Call system and was required to do so, and one from an excavator who made the required One-Call, met with Magellan personnel and indicated their intention to install no power poles within 75-feet of the ROW, and subsequently installed a power pole in the ROW only 20-feet from the pipeline. Of the remaining two near misses not classified as One-Call Violations, both were exempt from One-Call. If the excavation is shallower than 16 inches, then One-Call is not required, one excavation being from an electric fence installed over the ROW and the other from a 4-inch drain pipe installed across the ROW with an excavation only six-inches deep.

The six near misses were found by multiple means; two were discovered by aerial patrol, three by observers on the ground, and no means of discovery was stated for the remaining near miss. These instances demonstrate the importance of the aerial patrols and continued education of the public through Magellan's damage prevention program. They also show that no single piece of a TPD prevention program is capable of effectively mitigating damage.

The LMP commitment on pipeline surveillance as stated in LMP Section 3.5.4 is:

- Tier-II and Tier-III areas: Every 2.5 days, not to exceed 72 hours,
- Tier-I areas: Once a week, not to exceed 12 days, but at least 52 times per year, and
- Edwards Aquifer Recharge Zone: Daily (1 day per week shall be a ground-level patrol).

The data summarized under Item 56, Miles of Pipe Inspected by Aerial Survey by Month for 2009, show that Magellan exceeded these requirements in terms of the number of aerial and ground patrols. Magellan implemented a process improvement after the 2008 ORA Annual Report was issued, to perform ground patrols to supplement aerial patrols when poor weather prevents them. It appears that this process improvement has prevented other instances where aerial patrols were unable to inspect Tier II & III areas within 72-hours of the previous patrol. It is reasonable to conclude that the TPD prevention program substantially contributed to the absence of TPD incidents.

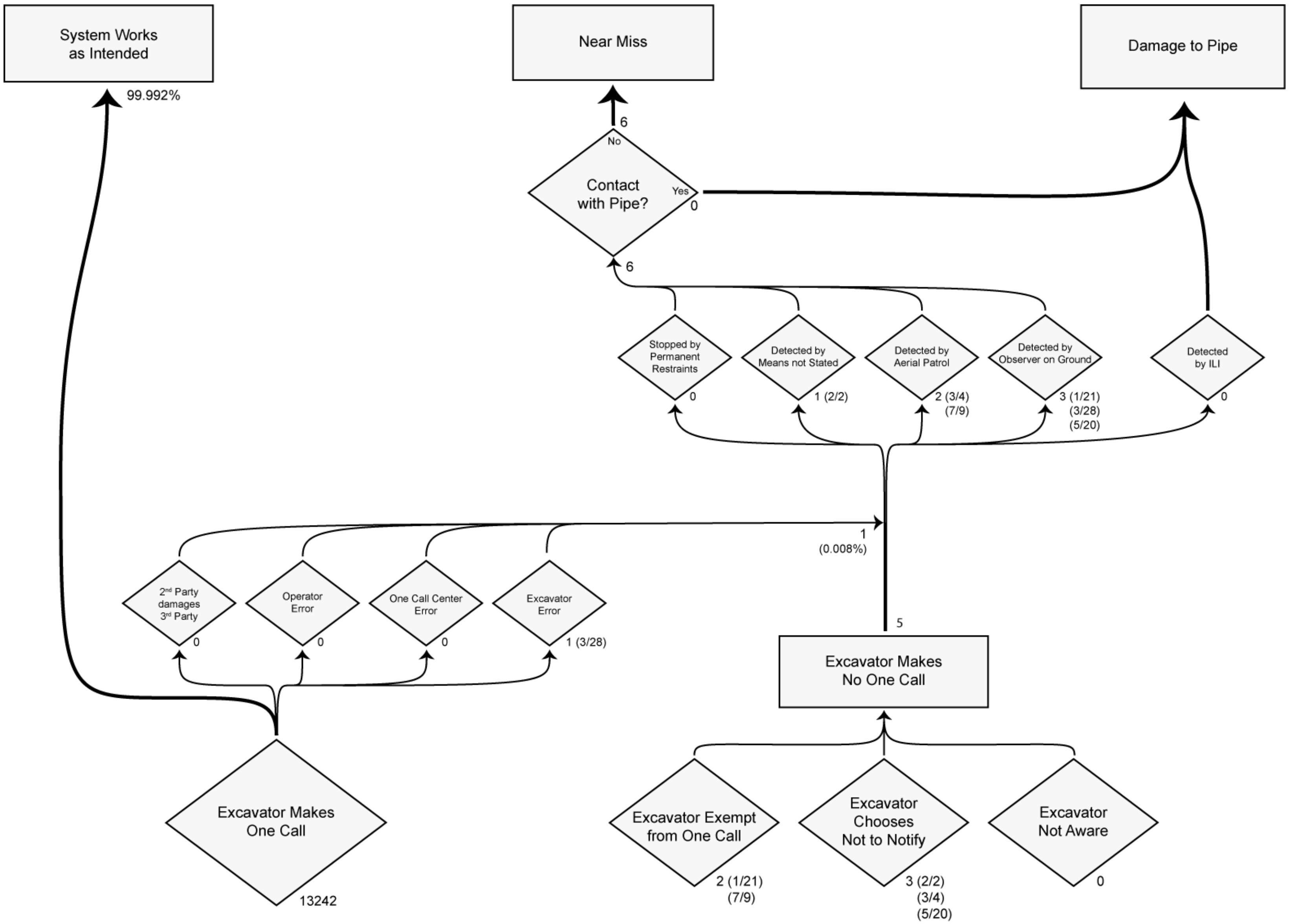

Figure 2. Flow Chart of 2009 One-Calls to the Longhorn System

Intervention Recommendations

Section 7.4.2 of the ORAPM specifies the requirement to run an ILI capable of detecting mechanical damage if three or more One-Call violations occur within a 25 mile interval within a 12 month period. Although there were three near-misses in 2008-2009 that occurred within a sliding 25-mile segment with 12 months of each other, only one was a One-Call Violation. Therefore, there is no requirement to conduct an additional ILI inspection with a geometry tool at this time even though one had been run in conjunction with the LMC 12 and 12A requirements. LMC 12A, requires that a “smart” geometry tool (a tool capable of detecting third party damage, such as TFI, HRMFL, or geometry tool) should be run no more than every three years after startup. Magellan has run a geometry tool in conjunction with LMC 12 (the requirement to run a UT within five years of startup).

No additional direct examinations are recommended at this time. Magellan should continue to carry out the same level of aerial surveillance and the same level of One-Call response that has occurred in 2009. Magellan should continue to carry out One-Call response in 2010 as specified in the LMP.

5.6 Stress-Corrosion Cracking

In the 58 years the Existing Pipeline has operated there have been no SCC failures and no SCC has been discovered at any location. However, in accordance with the LMC 19(a) and the 2003 OPS Advisory Bulletin ADM-05-03 “Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines,” Longhorn performed investigative digs each year for three years in areas susceptible to SCC.

During the first three years 2005-2007, Longhorn was required to inspect for SCC by selecting specific sites most susceptible to SCC. Subsequent inspection for SCC has continued as a supplemental examination when the pipe is exposed and examined for other reasons such as ILI anomaly excavations.

5.7 Facilities Other than Line Pipe

From the standpoint of facilities data acquired in 2009, one can conclude that active non-pipe facilities had no adverse impact on public safety. Facilities are monitored on an annual basis and the results tracked in an electronic database.

ORA Review of LPSIP Facility Integrity Program Results

A process hazard analysis was performed on the facilities other than pipe. This analysis produced a number of items to improve operational integrity. Items implemented are summarized on a management of change recommendation (MOCR) spreadsheet (Item 55). The summary of changes to facilities other than line pipe was reviewed.

Eight facilities were subjected to a complete inspection addressing more than 133 items related to safety, security, and environmental compliance. No major problems were identified based on a review of the inspection forms extracted from the database. The facilities for which the inspection data was provided were:

- Galena Park Pump Station
- Satsuma Pump Station
- Cedar Valley Pump Station
- Eckert Pump Station
- Ft. McKavett Pump Station
- Kimble County Pump Station
- Crane Pump Station
- Odessa Terminal

Five facilities incident data reports were received which concerned facilities in 2009, none of which were DOT reportable incidents. Only one of these incidents involved a spill of product (5 gallons) which was caused by filters that leaked one day after their replacement at a truck loading rack at the El Paso Facility. Of the other four incident data reports, two involved problems with prover balls, one was a leak while performing a hydrotest on facility piping, and one involved a quarter-sized rash on an employee where a spot of strainer liquid came in contact with his skin.

Integrity Review and Recommendations

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance. Magellan continues its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

6. LPSIP TECHNICAL ASSESSMENT

The LMP describes the philosophy of the LPSIP. By this philosophy, Magellan commits to “constructing, operating, and maintaining the Longhorn pipeline assets in a manner that insures the long-term safety to the public, and to its employees, and that minimizes the potential for negative environmental impacts.” The ORAPM provides for evaluating the effectiveness of the LPSIP on an annual basis using performance measures from three categories:

- Activity measures - proactive activities aimed at preserving pipeline integrity
- Deterioration measures - evidence of deterioration of pipeline integrity
- Failure measures - occurrences of failures or near failures

The status of each of these measures for 2009 is evaluated below.

Activity Measures

The activity measures are metrics that monitor the surveillance and preventive activities that Magellan has implemented during the period since the preceding ORA. These measures provide indicators of how well Magellan is implementing the various elements of the LPSIP. These measures are:

- Number of miles of pipelines inspected by aerial survey and by ground survey (by pipeline segment) in a 12-month period. Compare to the previous 12-month periods. This measure will be used to compare Longhorn Pipeline surveillance performance to previous year's surveillance of the same system. The goal would be 100-percent of the commitment.
- Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric will be compared to previous Magellan performance. This metric will be used to measure consistent effort by Magellan to protect the ROW and to prevent TPD. There will not be a "passing grade" established, because proper placement and maintenance of signs may lead to fewer signs replaced or repaired in future years, and this decline will not indicate any failing on the part of Magellan. On the other hand, tracking the replacement or repair of signs by pipeline segment may indicate third party vandalism or carelessness in certain segments of the system. This could be used as a leading indicator that additional public education might be needed in that region of the pipeline route.
- Number of outreach or training meetings (listed with locations and dates) to educate and train the public and third parties about pipeline safety. This metric will be used to gauge consistent effort by Magellan to educate the public regarding pipeline safety, with the goal of preventing TPD to the pipeline. There will not be a "passing grade" established, although the ORA contractor will review and compare the results of this metric with the results of the previous metric (sign placement, repair and replacement) to see if the effort at public education is being emphasized in the same geographic region where sign maintenance indicates problems. The number of meetings was recalculated in 2008 for all years. See Appendix B Item 58 for details.
- Number of calls ([sorted by Tier I, Tier II or Tier III) through the One-Call system to mark or flag the Longhorn Pipeline. This will help measure the effectiveness in the One-Call system in preventing TPD. The measure will be compared to previous years of Magellan records. Since this is a metric that is not subject to control by Magellan, a "passing grade" will not be established. However, this metric will also be compared to a failure metric described below (report of encroachments into the ROW that were not preceded by a One-Call contact). This comparison will allow overall measurement of how efficiently the One-Call process is being used. If the number of encroachments into

the ROW (without One-Call contacts) is expressed as a percentage of the total One-Call contacts for the year, then this percentage of failures to use the One-Call system should decrease over time, reflecting improvement in the integrity of the pipeline.

Table 5. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		203,081	197,234	188,884	187,931	181,308
Number of warning or ROW identification signs installed, replaced, or repaired		979	732	237	545*	475*
Number of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17
Number of calls through the One-Call system to mark or flag Longhorn's pipeline	Tier I	5,402	6,509	6,622	6,791	6,185
	Tier II	6,881	7,874	7,852	7,059	5,840
	Tier III	1,498	1,617	1,653	1,459	1,217

* The 2009 Annual Third-Party Damage Prevention Program Assessment lists these numbers for 2008 and 2009 as 536 and 460 respectively

Deterioration Measures

Deterioration measures are metrics that measure maintenance trends to indicate when the integrity of the system could be foreseen as potentially declining despite preventative actions.

Although the ILI runs are not being performed on the same segments from year to year nor is the same inspection tool being used, there is no discernable trend in anomalies found per mile.

POE evaluations show large variability from year to year because different segments of the pipeline are being inspected. A better indication of deterioration measures will appear when reinspection for corrosion is performed.

Hydrostatic leaks per mile have not been an indicator of performance because no hydrostatic reinspection tests have been performed for integrity purposes.

Table 6. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	NA	0.0212	0.035	0.006	0
	Tier II	NA	0.0208	NA	NA	0
	Tier III	0.192	NA	0.003	NA	0
Total number of anomalies (or leaks) per hydrostatic test		NA	NA	NA	NA	NA
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017

Failure Measures

Failure Measures are generated from leak history, incident reports, incident responses, and product loss accounting. These metrics can be used to gauge progress towards fewer spills and improved response, or alternatively to measure deterioration of overall system integrity. These measures are listed below. Response times, volumes, and costs are for DOT reportable leaks.

Table 7. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009
Number of leaks (DOT reportable)		2	0	1	3	0
Average response time in hours for a product release.	Tier I	Immediate	NA	Immediate	Immediate	NA
	Tier II	NA	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA
Average product volume released per incident	Tier I	5.7 Barrels	0	5.7 Barrels	0.4 Barrels	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Total product vol. released in the 12-month period	Tier I	17 Barrels	0	5.7 Barrels	1.3 Barrels	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Cleanup cost totals per year		< $100,000	$0	< $200,000	< $150,000	0
Cleanup cost per incident		< $35,000	NA	< $200,000	< $50,000	0
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	0	1	3	3
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0
Number of near misses to the pipeline by third parties		7	1	7	5	6
Number of service interruptions		115	165	155	74	16*

* Service interruptions counting changed between 2008 and 2009. In 2005-2008 service interruptions included all system stoppages including those related to business reasons, such as lack of throughput. In 2009 service interruptions only includes stoppages related to safety.

7. Integration of Intervention Requirements and Recommendations

Integration of Primary Line Pipe Inspection Requirements

Section 11 of the ORA Process Manual specifies integration of primary line pipe inspection requirements addressing corrosion, fatigue-cracking, lamination/H2S blistering, TPD, and earth movement. Magellan has four remediation commitments for using ILI for the pipeline, LMC 10, LMC 11, LMC 12, and LMC 12A. These commitments require Magellan to use an HRMFL tool for corrosion inspection in the first three months of operation, a TFI tool for seam inspection (which includes hook cracks) within the first three years of operation, a UT wall measurement tool within the first five years of operation for inspection of laminations and blisters, and a geometry inspection tool (deformation tool) at least every three years for inspection of TPD to the pipe. Future inspection requirements are based on reassessment intervals set by the ORAPM with the additional requirement that smart geometry tools must be run at least every three years.

There is overlap in anomaly detection capabilities of the various commercially available ILI tools and considerable variability in vendor availability and cost. As each cycle of the ORA is performed, additional data will become available not only from ILI tools, but also from routine maintenance reports and ILI anomaly investigation reports. This data will be integrated by the ORA process on a continuing basis to minimize the level of risk to the pipeline system integrity from each of the identified failure modes. To maintain and further reduce risk where possible, the ORA will identify and recommend the most appropriate ILI technology to obtain the necessary additional information. The use of one ILI tool technology may satisfy multiple inspection requirements for a pipe segment.

The tools Magellan has committed to use have multiple capabilities. The tools specified in Longhorn Mitigation Plan Commitments 10, 11, 12, and 12A have specified uses; however these tools also have other capabilities to address the threats outlined in the ORA. Longhorn had committed to run the HRMFL primarily for assessing corrosion metal-loss but the tool has secondary uses such as detecting mechanical damage and detecting indications of hydrogen blisters. Longhorn had committed to run the TFI for inspecting the long seam for anomalies and axial cracking in the pipe body. The TFI tool is also capable of detecting metal loss anomalies and mechanical damage. Longhorn had committed to run the UT tool for inspecting laminations and blisters. The UT tool can also characterize corrosion and has capabilities for detecting mechanical damage. Geometry tools are used for detecting and sizing deformation anomalies such as dents, buckles, blisters, and ovalities. The ORA directs integration of the use of these technologies to avoid duplication of effort, and to maximize the effectiveness of activities that are required by the ORAPM or recommended by the ORA Contractor.

Tables 8a and 8b are a compilation of the tools run to date, tools yet to be run as required by the LMP, and required reassessments as specified by the ORAPM. Earth movement, the fifth component for threat integration, is not included in Table 8a or 8b because it is currently addressed using surface surveys rather than ILI technology. Because of slow throughput on the pipeline Magellan was unable to meet LMC 12, the requirement to run a UT tool within five years of startup (January 26, 2010) for addressing the threat of hydrogen blisters, for two segments of the pipeline. Eckert to Ft. McKavett was five months late and Ft. McKavett to Crane was seven months late. Magellan continues to meet its commitments for Corrosion, Third Party Damage, and Pressure-Cycle Induced Fatigue ILI.

Table 8a. Existing ILI Runs and Planned Future Inspections

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Threats Addressed: Pressure-Cycle Induced Fatigue	Threats Addressed: Laminations and Hydrogen Blisters	Threats Addressed: Third Party Damage
Galena Park to Satsuma MP 0 to MP 34.1	Deformation	10-Jun-04				X
	HRMFL *	28-Oct-04	X			X
	HRMFL **	14-Dec-05	X			X
	TFI	6-Jul-07	‡	X		X
	Deformation	5-Oct-07				X
	Deformation	11-Sep-09				X
	UT	22-Sep-09	X		X	X
	Next Required Assessment		***22-Sep-14***	***2163***		***11-Sep-12***
Satsuma to Warda MP 34.1 to MP 112.9	HRMFL/Deformation	21-May-06	X			X
	Deformation	15-Dec-07				X
	TFI	20-Dec-07	‡	X		X
	Deformation	12-Oct-09				X
	UT	24-Nov-09	X		X	X
	Next Required Assessment		***24-Nov-14***	***2048***		***12-Oct-12***
Warda to Cedar Valley MP 112.9 to MP 181.6	HRMFL/Deformation	21-Jul-06	X			X
	TFI	19-Sep-07	‡	X		X
	Deformation	16-Oct-07				X
	Deformation	16-Dec-09				X
	UT	24-Jan-10	X		X	X
	Next Required Assessment		***24-Jan-15***	***2136***		***16-Dec-12***
Cedar Valley to Eckert MP 181.6 to MP 227.9	HRMFL/Deformation	15-Feb-07	X			X
	TFI	22-Mar-07	‡	X		
	Deformation	25-Jan-10				X
	UT	20-Feb-10	X		X	X
	Next Required Assessment		***20-Feb-15***	***2064***		***25-Jan-13***
Eckert to Ft McKavett MP 227.9 to MP 321.9	HRMFL/Deformation	19-Dec-06	X			X
	TFI	9-Nov-07	‡	X		X
	Deformation	23-Jan-08				X
	Deformation	27-Mar-10				X
	UT	25-Jun-10	X		X	X
	Next Required Assessment		***25-Jun-15***	***2040***		***27-Mar-13***
Ft.McKavett to Cran MP 321.9 to MP 457.5	HRMFL/Deformation	12-Oct-06	X			X
	Deformation	21-Dec-07				X
	TFI	8-Jan-08	‡	X		X
	UT	8-Jul-10	X		X	X
	Deformation	5-Aug-10				X
	Next Required Assessment		***8-Jul-15***	***2041***		***8-Jul-13***

* The HRMFL tool run in Oct-04 was not a complete run

** The HRMFL tool run in Dec-05 was used to complete the Oct-04 HRMFL run

‡ The TFI was used to remediate Phase I and Phase II corrosion anomalies and in some cases was used to remediate POE anomalies, but was not used to set the next corrosion reassessment using the POE process.

Table 8b. Existing ILI Runs and Planned Future Inspections

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Threats Addressed: Pressure-Cycle Induced Fatigue	Threats Addressed: Laminations and Hydrogen Blisters	Threats Addressed: Third Party Damage
Crane to Cottonwood MP 457.5 to MP 576.3	Deformation	2-May-07				X
	HRMFL/Deformation	21-Nov-08	X			X
	Next Required Assessment		***21-Nov-13***	*Not susceptible*	*Not susceptible*	***21-Nov-13***
Cottonwood to El Paso MP 576.3 to MP 694.4	Deformation	2-May-07				X
	HRMFL/Deformation	27-Mar-08	X			X
	Next Required Assessment		***27-Mar-13***	*Not susceptible*	*Not susceptible*	***27-Mar-13***
Crane to Odessa	HRMFL/Deformation	4-Nov-06	X			X
	Next Required Assessment		***4-Nov-11***	*Not susceptible*	*Not susceptible*	***4-Nov-11***
El Paso to Diamond Jct. (4 Lines)	HRMFL/Deformation	7-Mar-07	X			X
	Next Required Assessment		***7-Mar-12***	*Not susceptible*	*Not susceptible*	***7-Mar-12***

Integration of DOT HCA and TRRC Inspection Requirements

It is necessary for Magellan to be compliant with the DOT Integrity Management Rule, 49 CFR 195.452, for HCAs and the Texas Railroad Commission (TRRC) inspection requirements in 16 TAC §8.101 in addition to meeting the requirements in the LMP. The pipeline from Galena Park to El Paso is under DOT jurisdiction as well as the four laterals connecting El Paso to Diamond Jct. Only the section from Ft. McKavett to Crane (MP 312.9 to MP 457.5) does not contain any HCAs. The TRRC requirements apply only to the 8-inch lateral from Crane to Odessa.

The HCA rule states that an operator must establish five-year intervals, not to exceed 68 months, for continually assessing the pipeline's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the HCA to determine the priority for assessing the pipe. At this time, corrosion has proven to be the higher priority risk of the five threats to the pipeline integrity. Because of the requirements of the LMP and the multiple capabilities of each of the required tools, the HCA line pipe between Galena Park and Crane is being inspected in intervals less than five years. The HCA requirement will continue to be integrated into the ILI requirements as additional tool runs are completed to ensure the five-year interval required is not exceeded.

LMC 12A requires a "smart geometry" tool to be run every three years between Valve J-1 and Crane. Originally we extended this recommendation to the three segments beyond Crane, but in re-evaluating the requirement and the risk in these three new pipeline extensions it is reasonable to follow the HCA requirement (49 CFR 195.452) instead and require the smart geometry tool to run every five years. The risk for mechanical damage in these intervals is less because the pipeline is buried at least 30 inches deep where the Existing Pipeline upstream of Crane is often much shallower because this 30-inch depth of burial was not required at the time the pipeline was built.

The TRRC integrity rule requires that Magellan choose either a risk-based analysis or a prescriptive plan to manage the integrity of the 8-inch lateral from Crane to Odessa. Longhorn chose to complete a risk-based analysis which requires that initial assessment of the entire lateral shall be completed by January 1, 2011. An HRMFL-Deformation combination tool run was completed on March 7, 2007. The reinspection for mechanical damage in this interval was set to five years as required in the TRRC integrity rule using the same logic as expressed in the HCA requirement above.

Pipe Replacement Schedule

Pipe Replacements required by Lower Colorado River Authority (LCRA) Settlement

Longhorn had committed to replace five segments constituting approximately "6 miles of the Existing Pipeline in the Pedernales River watershed that is characterized as having time for a spill to travel to Lake Travis of 8 hours or less." The segments are defined as follows:

- Segment 1, approximately 8,836 feet extending from Engineering Station Number (ESN) 9968+64 to ESN 10057+00
- Segment 2, approximately 3,500 feet extending from ESN 10107+00 to ESN 10142+00
- Segment 3, approximately 3,000 feet extending from ESN 10179+00 to ESN 10209+00
- Segment 4, approximately 10,000 feet extending from ESN 10275+00 to ESN 10375+00
- Segment 5, approximately 5,000 feet extending from ESN 10459+00 to ESN 10509+00.

The commitment calls for installing new 18-inch-OD, 0.375-inch-wall, API 5L Grade X65 line pipe in these segments except in areas where a replacement of the 1950 pipe material has already been made. The replacement corresponding to Segment 5 was to be completed prior to startup (prior to June 10, 2002). Replacement of the other four segments is to be completed no later than seven years after startup (must be completed by January 26, 2012). From the evaluation of fatigue cracking, corrosion, laminations and hydrogen blistering, earth movement, and third party damage, KAI sees no reason to accelerate this schedule.

Other Pipe Replacements

None noted in 2009.

8. RECOMMENDED IMPROVEMENTS TO THE ORA PROCESS

KAI believes it is time for Magellan to update the corrosion section of the ORAPM. There are several changes recommended.

- Move beyond the concept of high resolution in-line inspection.
- Use current best practices for evaluating corrosion adjacent to or in girth welds and girth weld anomalies
- Eliminate parts of the ORAPM Corrosion section that are no longer needed such as determining intervention time based on using estimated corrosion rates and determining intervention time in the absence of ILI data.

All Modern ILI Tools are High Resolution

LMC 11 required Longhorn to run a High Resolution MFL tool to evaluate the pipeline for the presence of corrosion and other flaws. Section 4.3.6 of the LMP states that the POE analysis was designed to be used with high resolution tool data with an extensive number of verification digs and Section 4.0 of the ORAPM implements the use of HR ILI data to determine intervention requirement related to corrosion. When the LMP and ORA PM were written, standard resolution MFL tools still existed and high resolution MFL tools were considered better at detecting and sizing corrosion. Currently all MFL tools qualify as high resolution according to the MFL resolution conventions at the time the Mock ORA was written. In fact, many tools have higher sensor densities than existed on HRMFL tools at the time when the LMP and ORAPM were written. However there is nothing that prevents POE from being used on any resolution ILI tool, if the tool accuracy is assessed and the assessed accuracy is used for calculating POE and sufficient remediation is performed. But more accurate tools will allow fewer POE excavations in order achieve the same probability of exceeding a safe threshold. In addition, tool accuracy is not always dependent on the sensor resolution of a tool. Other factors affect the sizing accuracy such as corrosion shape, and in the case of MFL tools whether or not magnetite is present.

Evaluate Girth Weld Corrosion Using Current Best Practices

KAI reviewed the evaluation of girth welds and recommended replacing the evaluation of all corrosion anomalies within three inches of a girth weld with an evaluation of axial and circumferential corrosion and metal loss. This process was discussed with PHMSA on February 18, 2005, and at their request was reduced to a final report and delivered by KAI to Longhorn September 13, 2006. The ORA Process Manual needs revision to reflect this process change as it is currently being applied. Warman, Francini, and Mitchell's summary is extracted from KAI Report No. 06-92[3] as follows:

> The Longhorn Mitigation Plan (LMP Section 3.5.2.6) has an additional requirement to inspect reported metal loss within three inches of a girth weld. As it is currently defined, the requirement does not specify details regarding the depth of metal loss, the area affected, or whether the metal loss affects the girth weld itself. This lack of definition in combination with current ILI tool technology capable of reporting metal loss down to one percent of the pipe wall dimension has resulted in a significant number of indications that do not need remediation. For instance, 40 percent of these indications have metal loss less than 12.5 percent of the wall thickness, which is a threshold of metal loss normally considered insignificant to the integrity of a pipeline.
>
> Based on the above review, it is apparent that the provision in the LMP to investigate all metal-loss indications within three inches of a weld will result in a large number of field investigations for conditions that likely do not present an integrity concern to the pipeline.
>
> The historical basis of investigating metal loss within three inches of a weld is tied to conventional resolution MFL tools. These tools utilized analog recording devices with large sensor coils and sensor shoes, which resulted in averaging of magnetic-leakage signal response. In many cases, sizing of metal loss within three inches of a weld was imprecise due to a combination of the size of the sensor coils, changes in magnetic-flux density as a result of the weld, sensor lift off, and manual processing and interpretative technology. Most of the digital high-resolution MFL technology tools have rectified this problem and provided for more accurate sizing of metal loss adjacent to welds. Therefore, the current requirement of investigating all metal-loss features within three inches of a weld is not commensurate with technology required to be used on the Longhorn system, hence, there is solid technical justification to modify this requirement.
>
> A criterion to address corrosion adjacent or in girth welds should contain the following attributes.
>
> - Circumferential Pressure-Carrying Capacity of Metal Loss
>   This is currently being addressed using the POE process and ASME B31G, Modified B31G, RSTRENG, or other acceptable industry methods.
> - Regulatory Requirements

Metal loss greater than or equal to 50-percent-nominal wall thickness in an area that could affect a girth weld shall be investigated in accordance with 49 CFR §195.452 (h)(4)(iii)F.

- Longitudinal-Carrying Capacity of Metal Loss
  The analysis of metal-loss acceptability should be performed utilizing the Miller solution or other acceptable industry methods.

Research performed by the pipeline industry and the PRCI has shown that using "the Miller solution as modified by Wang et al." gives an appropriate expression for determining the load for blunt-tip flaws such as metal-loss corrosion. This approach has been validated by many years of practical application, by detailed numerical analysis, and by comparison to full-scale fracture tests. Although other assessment techniques for this problem have also been developed and seen used, KAI's review of the various techniques available indicated the Miller analysis to be the most suitable. In addition, "the Miller solution as modified by Wang et al." has been incorporated into the CSA Z622-2003 standard.

Eliminate Sections from the ORA Corrosion Section that are no Longer Needed

The ORA Process Manual Section 4 – Process to Determine Intervention Requirements Related to Corrosion contains parts that are no longer needed. Section 4.4 contains a procedure to determine the intervention time and method in the absence of ILI tool data. Section 4.6 contains a procedure to determine the future intervention time and method based on ILI data and using estimated corrosion growth rates.

Every section of the pipeline has been inspected using ILI so there is no need for section 4.4. In addition Magellan has completed UT ILI tool runs in 2010, so going forward all corrosion rates will be calculated using ILI data or field investigations so there will be no need to estimate intervention times based on estimated corrosion rates.

In addition, with the elimination of these two sections, there is only one possible path for calculating remediation of anomalies and reinspection intervals, so there is no need for a Top-Level Procedure section. Any remaining items from the top level procedure can be folded into Section 4.2 Overview and Timing.

Other Changes to Section 4.0 of the ORAPM

The confidence interval may be stated at any level. Currently the ORAPM specifies a 95 percent confidence level where most tool vendors use a confidence level of 80 percent when describing tool tolerance. Most (but not all) in the industry have standardized on the 80 percent level. The measurement error for ILI measurements is assumed to be normally distributed. Assuming this distribution, conversion from one confidence level to another is fairly straight forward.

When determining the probability of an anomaly having a burst pressure less than MOP or maximum allowable surge pressure (MASP), a calculation of the percent tolerance on the rupture pressure ratio (RPR) measurements should be allowed as an option rather than the more common depth tolerance. Although unity plots for depth can be mapped into pressure uncertainty, a more direct method is to compare burst pressures (or RPR) calculated from in-the-ditch and ILI measurements. Using this method, any errors associated with the conversion to depth, such as length errors, spacing between depth measurements, or corrosion pit grouping errors will be incorporated into the RPR tolerance.

Tool tolerance should be chosen based on the accuracy performed during the run or on the vendor stated tolerance if statistics are not sufficient to calculate one for the run. The ORAPM states the tolerance used will be the greater of the two, but this is often overly conservative and would require excessive repairs on very small anomalies when they are not necessary.

Performing POE on a joint-by-joint basis is no longer commonly performed. The recommendation to perform POE on a joint basis was the prevalent method when the Mock ORA was written. Currently POE is performed on an individual anomaly basis. Corrosion rate calculations are also not commonly done on a joint-by-joint basis and should be changed to allow calculation on a segment basis. Often the calculated corrosion rate will change within an ILI run, but there is usually insufficient data in a joint to calculate corrosion rates for each individual joint.

A proposed revision of Section 4.0 is included as Appendix C.

Table 9. Summary of 2009 Recommendations

Topic	Recommendation	ORA Ref Page
Corrosion section of the ORAPM	Recommend ORAPM section 4.be revised to incorporate the above changes and also eliminate sections no longer needed. This includes, evaluation of girth welds, corrosion adjacent or in girth welds, deleting the section covering evaluation of segments without ILI runs, and deleting the section estimating reinspection times using estimated corrosion rates.	33-35
Aseismic faults	It is recommended than monitoring for faults be changed from 2 times per year to every 5 years because fault movements are more than an order of magnitude smaller than anticipated in the EA	16-18

REFERENCES

1. Kiefner, J. F. and Mitchell, J. L., "Charpy V-Notch Impact Data for Six Samples of Seam-Weld Material from The Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 06-6 to Longhorn Partners Pipeline Company, (January, 19, 2006).
2. Kiefner, J. F., Johnston, D. C., and Kolovich, C. E., "Mock ORA for Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 00-49 to Longhorn Pipeline Partners, LP (October 16, 2000).
3. Kiefner, J. F., Kolovich, C. E., Zelenak, P. A., and Wahjudi, T. F., "Estimating Fatigue Life for Pipeline Integrity Management", Paper No. IPC04-0167, Proceedings of IPC 2004 International Pipeline Conference, Calgary, Alberta, Canada (October 4-8, 2004).
4. Verbeek, E.R., Ratzlaff, K.W., Clanton, U.S., Faults in Parts of North-Central and Western Houston Metropolitan Area, Texas, U.S. Geological Survey, September 2005.
5. Environmental Assessment, Appendix 9E, Longhorn Mitigation Plan Mandated Studies Summaries.
6. Warman, D.J., Francini, R.B., Mitchell, J.E., Development of an Acceptance Criterion for Corrosion within 3 Inches of a Girth Weld for the Longhorn Pipeline System, September 2006, KAI Final Report No. 06-92.

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APPENDIX A

Longhorn Mitigation Commitments (LMCs)			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
10	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a transverse field magnetic flux inspection (TFI) tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 3 years after system startup in Tier II and III areas	Material Defects, Corrosion, Outside Force Damage, and Previous Defects
11	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a high resolution magnetic flux leakage (HRMFL) tool and remediate any problems identified. Until Mitigation Item 11 has been completed, an interim MOP (MOPi) shall be established for the existing pipeline at a pressure equal to 0.88 times the MOP. (NOTE: 1.25 times the MOPi is equal to the Proof Test Pressure discussed in Mitigation Item 2 above). See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	Within 3 months of startup and thereafter at such intervals as are established by the Operational Reliability Assessment	Corrosion, Outside Force Damage and Previous Defects
12	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with an ultrasonic wall measurement tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 5 years after system startup	Corrosion, Material Defects, Outside Force Damage, and Previous Defects
12A	Longhorn shall perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a “smart” geometry inspection tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that no more than 3 years shall pass without an in-line inspection being performed using an inspection tool capable of detecting third party damage (e.g. TFI, HRMFL, or geometry)	Outside Force Damage

Longhorn Mitigation Commitments (LMCs)			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
19	Longhorn has performed studies evaluating each of the following matters along the pipeline, and shall implement the recommendations of such studies (See Mitigation Appendix, Item 19):	Prior to startup	Outside Force Damage, Corrosion, and Material Defects
	(a) Stress corrosion cracking potential.		Outside Force Damage and Corrosion
	(b) Scour, erosion and flood potential.		Outside Force Damage
	(c) Seismic activity.		Outside Force Damage
	(d) Ground movement, subsidence and aseismic faulting.		Outside Force Damage
	(e) Landslide potential.		Outside Force Damage
	(f) Soil stress.		Outside Force Damage
	(g) Root cause analysis on all historical leaks and repairs.		Outside Force Damage, Corrosion, Material Defects, and Operator Error
20	Longhorn shall increase the frequency of patrols in hypersensitive and sensitive areas to every two and one half days, daily in the Edwards Aquifer area, and weekly in all other areas. See the Longhorn Pipeline System Integrity Plan, Section 3.5.4.	Continuously after startup	Outside Force Damage, Corrosion, Material Defects, Leak Detection and Control
25	Longhorn shall develop enhanced public education/damage prevention programs to, inter alia, (a) ensure awareness among contractors and potentially affected public, (b) promote cooperation in protecting the pipeline and (c) to provide information to potentially affected communities with reguard to detection of and responses to well water contamination. See the Longhorn Pipeline System Integrity Plan, section 3.5.4. See Mitigation Appendix, Item 25. (This item has been superseded in large part by API RP 1162.)	Continuously after startup	Outside Force Damage, Leak Detection and Control

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APPENDIX B

New Data Used in this Analysis

The Appendix describes new data used in the analysis for this ORA Annual Report. It is divided into 16 sections specified in the ORA Report Outline from the ORAPM. In addition the ORA Process Manual identifies 78 items consisting of data, data logs, and reports the ORA contractor must review and consider to evaluate the effectiveness of the LPSIP and to assess whether or not Magellan is meeting the commitments of the LMP. A list of these 78 items is contained in Appendix B in the ORAPM. Each of the 78 data items is included under the appropriate ORA Report Data Sections described above.

4.1 Pipeline/Facilities Data

Mainline (Items 3, 7, 8, 9, 10, 11, and 12)

No new data

Pump Stations (Item 15)

No new data

Tier Classifications and HCAs (Items 1 and 2)

No new data

Charpy V-Notch Impact Energy Data (Item 14)

No new data

Mill Inspection Defect Detection Threshold (Item 13)

No new data

4.2 Operating Pressure Data

For Items 21, 22, and 23, KAI received pressure and flow data for Galena Park, Satsuma, Cedar Valley, Kimble County, Crane, and El Paso Pump Stations. The data is collected in 1-minute intervals and sent on a monthly basis. Data has been received for pressure cycles since September 17, 2004.

4.3 ILI Inspection and Anomaly Investigation Reports

ILI Inspection Reports (Items 39, 40, 41, 44, 45 and 47)

Data was received from the following TFI runs and evaluations completed in 2009.

Table B-1a. Excavations Completed in 2009

Line Segment	18" Cedar Valley to Eckert	18" Crain to Cottonwood	18" Cottonwood to El Paso
ILI Date	3/22/2007	11/21/2008	3/27/2008
Maintenance Report	yes	yes	yes
Tier 1	4	16	2
Tier 2	0	0	0
Tier3	0	0	0
Total Digs	4	16	2
HCA	0	0	0
Non-HCA	4	16	2

Table B-1b. Anomalies Called that were Addressed in the above Excavations

Line Segment	18" Cedar Valley to Eckert	18" Crane to Cottonwood	18" Cottonwood to El Paso
Ext ML	0	0	0
Seam Weld ML	13	0	0
Dent	0	1	0
Ext ML	0	5	0
Int ML	0	27	5

Results of ILI for TPD between J-1 and Crane (Item 77)

See above.

Results of Ultrasonic ILI for Laminations and Blisters between J-1 and Crane (Item 78)

Results expected in 2010.

4.4 Hydrostatic Testing Reports

No new hydrostatic tests were conducted.

Hydrostatic Leaks and Ruptures (Item 75)

No new data was obtained.

4.5 Corrosion Management Surveys and Reports

Corrosion Control Survey Data (Item 24)

Corrosion Control Survey data was received from Magellan covering 2009.

TFI MFL ILI Investigations (L and d Results) (Item 35)

See section 4.3 above.

External Corrosion Growth Rate Data (Item 36)

No new data. ILI growth rates are expected in 2010 when MFL and UT ILI runs can be compared.

Internal Corrosion Coupon Results (Item 37)

Three internal corrosion coupon reports were reviewed for the 2009 annual report. Three lines were sampled with coupons placed in the 8-inch Odessa lateral at Crane, the Plains 8-inch lateral at El Paso, and the 18-inch main line at El Paso. Little to no corrosion was observed with measured corrosion rates all much less than 1 mil per year.

Table B-2a. Internal Corrosion Coupon Results 8-inch Odessa Lateral at Crane Station

Inserted	Removed	Exposure (days)	Rate (MPY)	Portion of Test Surface Rusted	Under Holder Attack	Comments
1/2/2009	5/1/2009	119	0.00	None	none	
5/1/2009	9/1/2009	123	0.00	None	none	
9/1/2009	1/4/2010	125	0.03	< 0.1%	light	

Table B-2b. Internal Corrosion Coupon Results 8-inch Plains Lateral at El Paso Terminal

Inserted	Removed	Exposure (days)	Rate (MPY)	Portion of Test Surface Rusted	Under Holder Attack	Comments
1/2/2009	5/1/2009	119	0.00	None	none	
5/1/2009	9/1/2009	123	0.00	None	none	
9/1/2009	12/31/2009	121	0.00	None	none	

Table B-2c. Internal Corrosion Coupon Results 18-inch Main Line at El Paso Terminal

Inserted	Removed	Exposure (days)	Rate (MPY)	Portion of Test Surface Rusted	Under Holder Attack	Comments
1/2/2009	5/1/2009	119	0.15	None	none	
5/1/2009	9/1/2009	123	0.00	None	none	
9/15/2009	12/31/2009	107	0.00	None	none	

Line Pipe Anomalies/Repairs (Item 43)

See section 4.3 above.

All ILI Metal Loss and Deformation Related to Line Pipe Anomalies (Item 44)

See section 4.3 above.

All ILI Pipe Wall Deformation, Out-of-Roundness, 3D Location Related to the Threat of Third-Party Damage (Item 45)

See section 4.3 above.

Number of Anomalies Measured by ILI, by Tier and by DOT Repair Conditions Based on the Annual Assessment of the LPSIP (Item 74)

See section 4.3 above.

4.6 Fault Movement Surveys and Natural Disaster Reports

Pipeline Maintenance Reports at fault crossings (Item 30)

Maintenance reports were received showing that covers were installed over the benchmarks.

Periodic fault benchmark elevation data (Item 31)

A Draft Second-Half 2009 Semi-Annual Fault Displacement Monitoring Report dated 04 February 2010 was received which covers semi-annual fault measurements at the four fault monitoring sites since inception in mid 2004 through December 2009.

Pipeline Maintenance Reports for Stream Crossings (no item number)

Scour reports were received for the two stream crossings requiring bi-annual monitoring, the Colorado River and its tributary Pin Oak Creek.

Flood Monitoring (no item number)

Flood monitoring spreadsheets were received for Colorado River, Pin Oak Creek, and the Pedernales River. The Pedernales River is the only one of these three that entered flood stage and it did so on October 22, 2009.

4.7 Maintenance and Inspection Reports

Depth-of-Cover Surveys (Items 19 and 27)

No new surveys were made in 2009.

Seam Anomaly/Repair Reports Related to Fatigue Cracking of EFW and ERW Welds, and Seam Anomalies (Items 33 and 34)

Summarized in section 4.3 above.

Mechanical Integrity Inspection Reports (Item 46)

None found.

Mechanical Integrity Evaluations (Item 47)

None found.

Facility Inspection and Compliance Audits (Item 48)

Comprehensive inspections of each facility are made by Magellan personnel using a detailed check list called a Facility Inspection Form. The multi-page form contains 17 sections, and each section has a list of points to inspect or items to check with spaces for indicating yes or no regarding whether or not a given point or item met the standard set by company policies or procedures. Spaces are also provided for comments such as actions necessary to bring the point or item into compliance. The 17 sections and the number of points in each section are:

1. Record Keeping (retention time in years is indicated) – Points 1-26
2. Posting of Notices Signs and Posters – Points 27-36
3. Housekeeping and Sanitation – Points 37-42
4. Exits – Points 43-47
5. Ladders and Scaffolds – Points 48-64
6. Tools, Equipment, and Machinery – Points 65-80
7. Electrical/Lighting – Points 81-92
8. Vehicles and Equipment – Points 93-98
9. Flammable Liquid Storage – Points 99-105
10. Hazardous Materials – Points 106-113
11. Personal Protective Equipment Provided and in Good Condition – Points 114-118
12. Material Handling Equipment: Good Condition – Points 119-121
13. Welding, Cutting, and Brazing – Points 122-124
14. Pump Rooms – Points 125-130
15. Miscellaneous – Points 131-136
16. Environmental – Points 137-154
17. Security – Points 155-163.

Maintenance Progress Reports (Item 73)

A computerized mechanical integrity /preventive maintenance system was implemented in 2007 and all DOT station inspections were scheduled utilizing this system. Maintenance was tracked according to the schedule at hourly, weekly, monthly, quarterly, semi-annual, tri-annual, and annual intervals.

4.8 Project Work Progress and Quality-Control Reports

Access to Action Item Tracking and Resolution Initiative Database (Item 49)

Table B-3. Number and Status of Action Items per Month

Action Items	Jan*	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep*	Oct	Nov	Dec	Total
New	1	5	0	2	17	1	3	2	0	7	0	0	**37**
Closed	4	3	1	1	15	5	2	2	1	1	6	5	**41**
Open at End of Month	11	13	12	13	15	11	12	12	18	17	11	6	

* Inferred — no spreadsheet received for months 0110 & 0910. Also received two different spreadsheets labeled 0710 — assumed first was for 0610. Although months new action items were added or completed ones were closed may be off by one month, totals for year should be correct.

4.9 Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-4. Service Interruptions per Month for 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total*
No./Month	2	1	0	0	4	5	1	1	0	1	1	0	16

* From the Daily Ops Report ending Dec 31.

4.10 Incorrect Operations and Near-Miss Reports

Incorrect operations were documented in the many internal incident investigation reports, none were reportable to DOT in 2009.

There were 6 ROW near misses reported as part of the TPD Annual Assessment and as individual internal incident investigations.

4.11 One-Call Violations and Third-Party Damage Prevention Data Right-of-Way (ROW) Surveillance Data (Item 50)

A complete log of aerial and ground surveillance data is maintained by Magellan and received by KAI monthly. Each entry on the log represents a report of an observation by the pilot that represents or could represent the encroachment of a party on the ROW with the potential to cause damage to the pipeline. The observations range in significance from observations that turn out to have no impact on the ROW to those that could result in damage to the pipeline without intervention on the part of the pipeline operator. Each observation on the log is identified by location (milepost and GPS coordinates), by date of first observation, and whether the activity is an emergency or non-emergency observation. A brief description of the observation is recorded, and the action to be taken is recorded as well.

The number of One-Call violations is also summarized as part of the TPD Annual Assessment. In 2009 there was a single One-Call violation, the same as 2008.

Third-Party Damage (TPD), Near Misses (Item 51)

The number of TPD near misses for 2009 was six. These were taken from the 2009 TPD Annual Assessment and Incident Data Reports. Tier location was determined by comparing the location to pipeline strip maps.

Table B-5. Number of Third-party Damage near Misses.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Tier 1	1	1	2										4
Tier 2					1		1						2
Tier 3													0
Total	1	1	2	0	1	0	1	0	0	0	0	0	6

Unauthorized ROW Encroachments (Item 52)

There were three (3) unauthorized ROW encroachments documented in the 2009 TPD Annual Assessment.

TPD Reports on Detected One-Call Violations (Item 53)

One-Call violations are defined on a state-by-state basis. For the Longhorn ORA they are defined by the Texas Underground Facility Damage Prevention and Safety Act as referenced in the 2009 TPD Annual Assessment. Of the six near misses on the pipeline in 2009 four were classified as One-Call violations on the Incident Investigation Reports, five were classified as One-Call Violations in the 2009 TPD Annual Assessment. Of the two near misses not classified as One-Call violations, neither involved mechanized excavation equipment nor did they exceed 16-inches in depth, so both were exempt from one-call.

TPD Reports on Changes in Population Activity Levels, Land Use and Heavy Construction Activities (Item 54)

The 2009 TPD Annual Assessment shows and 8-percent drop in Non-Company activity level from unique aerial patrol observations. This is primarily due to a decrease in housing development, and misc TP activity.

Miles of Pipe Inspected by Aerial Survey by Month in 2008 (Item 56)

Total possible mileage includes the 694 mile main line plus the 29-mile lateral from Crane to Odessa and the lateral from El Paso Terminal to Diamond Junction. Tier III and Tier II areas must be inspected every 2½ days not to exceed 72 hours. The Tier I area from the Pecos River to El Paso only needs to be inspected once per week (not to exceed 12 days). Daily patrols are also required over the Edwards Aquifer Recharge Zone with one patrol per week to be a ground-level patrol. In an attempt to meet this requirement through aerial patrols, the pipeline ROW was flown daily from the Pecos River to Galena Park. Regular ground patrols were made in two particular areas, the Edwards Aquifer recharge zone (Milepost 170.5 to Milepost 173.5) and the wetlands at Manchaca Road (Milepost 168.5 to Milepost 168.9). The Manchaca Road not being explicitly required in the LMP was discontinued in April 2009. The cumulative miles of patrols for these four areas by month were as follows:

Table B-6. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total*
Edwards Recharge Zone Ground Patrols	28	14	22	17	14	14	11	14	14	11	14	28	202
Wetlands Patrols	16	15	16	11	0	0	0	0	0	0	0	0	57
Galena Park to Crane	14,915	13,030	12,840	13,747	15,116	15,627	15,508	16,084	13,327	11,718	13,965	11,637	173,764
Crane to El Paso	1,056	1,056	1,056	1,215	940	1,056	1,320	1,056	1,320	1,056	1,056	1,349	13,780
Total	16,015	14,115	13,934	14,990	16,070	16,697	16,839	17,154	14,661	12,785	15,035	13,014	181,308

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas from the Galena Park to Pecos River at least every 72 hours for the entire year. There were three episodes of bad aerial patrol weather in March, September, and December 2009, where significant ground patrols were organized to complete the necessary patrols. Although October 2009 completed significantly fewer miles flown than other months, the required patrols within 72-hours were met. This is probably fortuitous because there were many single days when a patrol could not be performed and one interval where no patrols could be performed for two days.

Number of Pipeline Signs Installed, Repaired, Replaced by Month (Item 57)

The number of pipeline markers repaired or replaced is 460 and comes from the TPD Annual Assessment. This is a 14-percent decrease from 2008. The Mitigation Plan Scorecard lists the monthly sign replacements as follow with the annual total differing slightly from the TPD Annual Assessment.

Table B-7. Markers Repaired or Replaced

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	0	11	24	13	265	40	57	0	0	22	20	23	475

Number of Public Outreach or Educational Meetings Regarding Pipeline Marker Signs and Safety (Item 58)

Magellan participates in a variety of outreach efforts for the public and the stakeholders along the pipeline which are summarized in TPD Annual Assessment.

Table B-8. Educational and Outreach Meetings from 2005-2009

EVENT	2005	2006	2007	2008	2009
Emergency Responder / Excavator Meetings	14	12	11	11	11
School Program:					
School Program - Houston	2	2	3	4	
School Program - Austin	3	2	7	3	4
Neighborhood Meetings	2	2			
Misc. Meetings:					
Creekside Nursery	1				
Cy Fair ISD	1				
Region 6 LEPC Conference (Houston)	1				
Public Events	4		4	3	2
TOTAL	**28**	**18**	**25**	**21**	**17**

NOTE: Public meetings were tallied for the years 2005-2009 as follows:

Emergency Responder / Excavator Meetings: Count only the number of meetings (not the total number of counties).

School Program: Houston Program - count the schools that request the Safe at Home Program; Austin Program - count only schools where Longhorn/Magellan gave presentations.

Neighborhood Meetings: Phased out in 2007, and was replaced by enhancements to school program and public events.

Misc. Meetings: Count all other meetings that are not public events (i.e. daycares, church meetings, public speaking engagements, etc.).

Public Events: Count events such as rodeos, county fairs, fundraisers, Austin Cave Festival, Safety Day Camps, etc.

Number of One-Calls by Month by Tier (Item 59)

The number of reported One-Calls by month by tier for 2008 is in Table B-9 below.

Table B-9. Number of One-calls by Tier

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	508	435	480	483	528	477	501	547	918	534	432	342	6185
II	456	379	409	442	479	470	517	559	839	519	447	324	5840
III	92	75	85	94	100	102	108	120	176	106	91	68	1217
Total	**1056**	**889**	**974**	**1019**	**1107**	**1049**	**1126**	**1226**	**1933**	**1159**	**970**	**734**	**13242**

Public Education and Third-Party Damage Prevention Ads Quarterly (Item 60)

Annual Mailing**:** Magellan distributes bilingual brochures annually to all postal addresses, including residences, businesses, schools, etc. within a two-mile radius either side of the pipeline ROW in rural areas and a one-quarter mile radius either side of the ROW in metropolitan areas. These brochures contain information on pipeline safety, including how to recognize abnormal operating conditions. The objective of this mailing is to communicate with the residents and businesses that are located in close proximity to the Longhorn system; and provide them information about pipeline safety, public awareness of underground utilities, damage prevention and emergency preparedness.

- The annual mailing was mailed October 23, 2009.
- Advised the Operations Managers, Asset Integrity Supervisors, and Operations Control Manager of the annual mail out messages at least 10 days before the mail outs.
- Distributed ~84,500 pieces to stakeholders along the ROW. Supplemental mailings in seven (7) segments along the ROW to the affected public in ~229 households regarding ROW near misses and a potential pipeline relocation project.

Public Official Program: Magellan informs public officials of the location of the Longhorn pipeline and dangers associated with development and encroachments adjacent to the pipeline. Magellan works within the local network of public officials, city and county planning departments, zoning and building permit offices and agricultural agencies to ensure safe development near our pipeline. The LMP states that we must reach non-emergency response government agencies that are exempt from one-call mandates to provide them with maps of the system and inform them of the presence of the pipeline in order to maintain public safety.

- In 2009 the Public Official Program consisted of a Spring Emergency Responder Newsletter, an Emergency Responder Brochure and a Safety Information Newsletter that was sent to 389 Public Official recipients.
- Magellan is in the process of identifying all stakeholder email addresses from the Face-to-Face Liaison Program, as they will be included as an enhancement to this program and

added to the existing addresses for the next emergency responder email, which is scheduled to go out in Q2, 2010.

Website: The Longhorn website is utilized as a communication tool to inform the public about pipeline safety, damage prevention, emergency preparedness and mitigation measures, among other items. In addition, Magellan is required to post information about the Longhorn system's operations such as the annual self-audit report and results of the annual ORA to make it available to the public.

- In 2009, the Longhorn website received 18,705 hits from January to May. In August the Longhorn page was posted on Magellan's corporate web page, www.magellanlp.com. In September the Longhorn domain www.longhornpipeline.com was automatically redirected to the Magellan web page. In November, Magellan began tracking the number of hits/visits on the Longhorn specific page and it received 714 hits for the remainder of the year.
- Magellan website was reorganized during Q4 to more effectively communicate with both the public and the press.

Number of Website Visits to Safety Page by Month (Item 61)

The number of visits to the safety section of the website per month was:

Table B-10. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	Jul*	Aug*	Sept*	Oct*	Nov	Dec
Plan	30	37	163	102	104	136						
Identifying Pipelines	26	20	349	96	104	118						
Quarterly Reports	64	80	19	104	91	156						
Recognizing a Leak	11	4	36	80	83	92						
Responding to Emergencies	2	4	4	79	99	91						
Safety Commitment	14	13	7	96	85	112						
Emergency Contact	14	11	13	92	83	120						
Annual report	145	111	79	144	121	212						
Call Before You Dig	10	7	11	92	92	117						
Emergency Preparedness	7	6	3	80	107	102						
Mitigation Plan	9	5	16	71	65	79						
Public Awareness	6	9	12	89	83	82						
ROW	21	23	22	144	87	126						
Damage Prevention	7	4	3	82	82	98						
School Program	10	26	15	296	196	260						
Safe at Home	10	8	6	96	100	132						
Public Events	11	17	11	110	87	117						
Safety/Environment**											99	87
Safety/Environment – Call Before You Dig**											47	21
Safety/Environment – Pipeline Safety**											65	50
Safety/Environment – System Integrity Plan**											62	42
Safety/Environment – Longhorn Info.**											101	84
Safety/Environment – Pipeline Emergencies**											24	22
Safety/Environment – Call Before You Dig Video***											2	2
Home Page – 811 Logo***											2	4
Total	397	385	769	1853	1669	2150					402	312

* The Longhorn website was moved to the Magellan website, categories were combined and consolidated. Until November there was no way to discriminate and count website visits to the Longhorn section of the website.
** Started November 3
*** Started November 17

Number of ROW Encroachments by Month (Item 67)

Table B-11. Table of ROW Encroachment by Month

Encroachments	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	5	6	7	4	6	4	5		4	13	2	8	64
Unauthorized			1		1		1						3
Total	**5**	**6**	**8**	**4**	**7**	**4**	**6**	**0**	**4**	**13**	**2**	**8**	**67**

Number of Physical Hits to Pipeline by Third Parties, by Month (Item 68)

No physical hits to the pipeline were reported in 2009, the same as in 2008, 2007, and 2006.

Annual TPD Assessment Report (Item 71)

The Longhorn System 2009 Annual Third Party Damage Prevention Program Assessment (TPD Annual Assessment) was received May 17, 2010. Much of the data received in this report is used to summarize other parts of Section 4.11 and section 5.5 on third party damage prevention.

One-Call Activity Reports (Item 72)

A summary of One-Call activity by month is supplied in Table B-12 below as extracted from the TPD Annual Assessment. Results show that of the 13,222 On-Call notifications 7.1 percent required filed locates (marking of the pipeline location in the field). This is a 1.5 percent decrease over 2008 when 8.6 percent of the 15,465 One-Call notifications required field locates.

Table B-12. One-call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	499	45	1056
Feb	387	86	889
Mar	443	66	974
Apr	454	70	1019
May	499	86	1107
Jun	456	57	1049
Jul	509	76	1126
Aug	588	87	1226
Sep	905	151	1933
Oct	541	93	1159
Nov	481	59	970
Dec	300	66	734
Totals	6062	942	13242

4.12 Incident, Root Cause, and Metallurgical Failure Analysis Reports

Documentation from several internally reported incidents was received. Of these, most were very small incidents with spills less than five (5) gallons, near misses where no spill occurred, vehicle incidents, or non-jurisdictional incidents unrelated to the pipeline. For the first time since the start of the ORA process, none were significant enough to be reportable to DOT/PHMSA.

4.13 Other LPSIP/RRA Studies, Evaluations, and Program Data

A summary table of Management of Change Recommendations (MOCRs) was received for item 55 hazard analysis reports. A spreadsheet showing results from the Relative Risk Assessment was received.

4.14 Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity PHMSA Advisories

September 30, 2009

PHMSA-2009-0158;Weldable Compression Coupling Installation ADB-09-02

SUMMARY: Pipeline and Hazardous Materials Safety Administration (PHMSA) published advisory bulletin, ADB-09-02, to remind pipeline owners and operators of the importance of installing weldable compression couplings in accordance with manufacturer procedures and to follow appropriate safety and start-up procedures. The failure to install weldable compression couplings correctly, or the failure to implement and follow appropriate safety and start-up procedures, could result in a catastrophic pipeline failure. PHMSA urges operators to review, and incorporate where appropriate into operators' written procedures, the manufacturer's installation procedures and take any other necessary safety measures for safe and reliable operation of pipeline systems.

December 7, 2009

PHMSA-2009-0349; Pipeline Safety: Operator Qualification (OQ) Program Modifications ADB-09-03

SUMMARY: The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this Advisory Bulletin to inform pipeline operators about the standardized notification process for operator qualification (OQ) plan transmittal from the operator to PHMSA. This Advisory Bulletin also informs operators about the addition to PHMSA's glossary of definitions of the terms ``Observation of on-the-job performance'' as applicable to determining employee qualification and ``Significant'' as applicable to OQ program modifications requiring notification. Finally, it makes other miscellaneous clarifications to assist operators in complying with OQ program requirements.

4.15 DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2009.

4.16 Literature Reviewed

See references.

APPENDIX C

4.0 - Process to Determine Intervention Requirements Related to Corrosion

4.1 Introduction

This section of the ORA Process Manual addresses the issue of corrosion anomalies and the growth of these corrosion anomalies over time in line pipe within the Longhorn Pipeline System.

Corrosion Control

Corrosion is a time dependent failure mechanism. With comprehensive monitoring and control, the time to failure can be extended well into the future. Future failures can be prevented by appropriate and timely intervention to confirm that the control measures are performing properly.

One method of intervention is periodic hydrostatic testing to a level 1.25 times the MOP. Another method is the use of a reliable ILI metal loss detection tool, which can be substituted for a hydrostatic test.

From 1966 to 1995, there were two releases that were attributed to corrosion, one taking place in 1973 and one in 1974. The LMP [1] describes an extensive Corrosion Management Plan (CMP) to control the extent to which corrosion can occur within the system.

The intervention method defined by the LMP is a MFL ILI tool. The initial MFL inspection for the valve J1 to Crane section of the system must be performed within 3 months of system startup. Thereafter, the interval is to be determined by this ORA process. The ORA process described herein will determine the inspection timing for the other sections of the pipeline system (e.g. Crane to Odessa).

ILI inspection data can be used for addressing immediate integrity concerns using deterministic methods such as those referenced in 49 CFR §195.3. The LMP describes the intervention action required under the LPSIP and the associated timescales for anomalies reported following the MFL inspection.

The data obtained from a MFL inspection can be further utilized using statistical methods that have been developed for this purpose [1,2,3]. These methods can be used to manage the long-term integrity of pipeline systems. This statistical or probabilistic approach has the advantage that the effects of the ILI tool inaccuracies can be considered on a rational basis. A numerical probability can be assigned to any unexcavated anomaly that indicates, given the tool measurements of the anomaly, the depth of corrosion could be great enough to cause a leak, or on a calculated burst pressure basis, the calculated burst pressure of the corrosion anomaly could be less than the maximum operating or surge pressure. The value of making further excavations at some point in the future can be calculated and re-inspection intervals can be determined.

Monitoring the Possibility of Corrosion-Related Leaks

This section of the ORA manages line pipe integrity from the threat of failure due to corrosion by calculating the probability that a corrosion anomaly, as reported by the ILI process, exceeds certain criteria directly related to line pipe integrity. This probability of exceedance (POE) can be calculated for every anomaly on a depth basis for corrosion anomalies that could lead to a leak and on a pressure basis for corrosion anomalies that could lead to a rupture of the pipe. The POE for depth (POE_D) calculates the probability that an anomaly detected by an ILI tool is deeper than 80% of the wall thickness. The POE for pressure (POE_P) calculates the probability that the calculated burst pressure of the anomaly will be less than the MOP or the MASP where surge pressures may exceed the MOP (typically 1.1 times MOP). Those anomalies that have a POE equal to or greater than 1×10^{-7} (1 in 10,000,000 chance) for either depth or pressure will be investigated and repaired if necessary.

POE values less than 1×10^{-7} indicate corroded areas that are considered to not warrant investigation by the pipeline operator. These anomalies will have a less than 1 in 10,000,000 chance that the calculated burst pressure is less than the MOP or MASP and/or that the anomaly depth exceeds 80% of wall thickness.

The POE methodology can also be used to predict the effects of time on corrosion anomalies. Calculated or estimated corrosion rates can be applied to each anomaly in the pipeline that has not been subject to a repair action. The time interval for the POE to rise above a certain value can be calculated and this time interval used to determine the timing of the next intervention action (e.g., ILI tool run). For this ORA process, the next inspection will be triggered when the POE for the burst pressure of the worst remaining anomaly being less than the MOP or MASP equals 1×10^{-5} (1 in 100,000 chance).

This ORA process follows the methodology outlined in the LMP and incorporates:

- Historical and current data on the existence of corrosion and potential for corrosion growth
- The environmental Tier I, II and III segmentation of the pipeline system
- The HCA segmentation of the pipeline system pursuant to the DOT Rule for Pipeline Integrity Management in High Consequence Areas (49 CFR 195.452)
- The use of ILI tools to examine the line pipe for corrosion defects
- The use of ILI multiple tool runs to calculate corrosion growth rates. Where such data is unavailable, rates will be derived from an analysis of pipeline operator data or estimated corrosion growth rates based on soil resistivity will be used.
- The application of the POE methodology to line pipe without prior ILI data
- The use of investigation and repair data on line pipe corrosion from the pipeline operator
- Incident investigation, routine maintenance and root cause analysis reports on corrosion investigations of the line pipe

4.2 Overview and Timing

The process is defined in two procedures further described in the following sections:

1. A procedure to determine ILI anomalies that have a POE equal to or exceeding a probability of 1×10^{-7} and for which investigative action is required (**Section 4.3**)
2. A procedure to determine the future intervention time and method based on ILI data and using corrosion growth rates calculated from correlating current and previous ILI data or field investigation(s) (**Section 4.4**)

The LMP requires that the ORA process related to corrosion be performed:

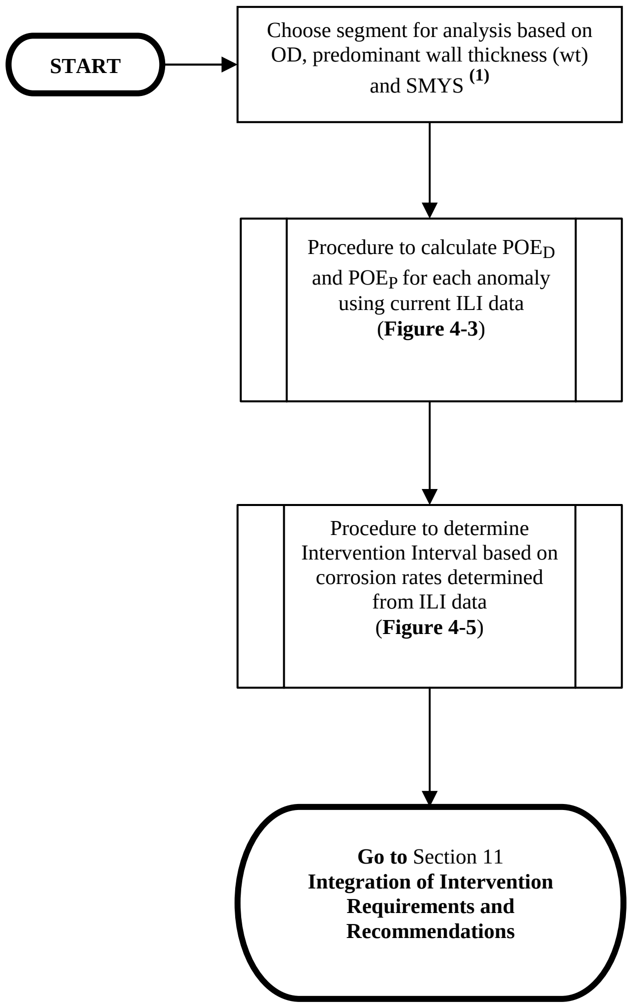
- Twelve months after startup, but not to exceed 15 months before implementation
- Then at intervals of 12 months (but not exceeding 15 months) for the life of the pipeline system unless an event dictates a more frequent implementation of the process over a specified period

The procedures described herein will follow the above schedule for all line pipe in the Longhorn system to determine the intervention time for re-inspection by a ILI tool.

The two procedures can be tied together using the flow diagram shown in **Figure 4-1**.

The logical pipeline segmentation for assessment is between ILI tool traps. As a trap-to-trap segment can contain significant lengths of pipe with different pipe properties (e.g. wall thickness), the procedure allows for the assessment to be based on outside diameter (OD), predominant wall thickness (wt) and specified minimum yield strength (SMYS), if required. Calculations for each anomaly will be based on the actual nominal wall thickness regardless of predominant thickness in a segment. Nine segments of the Longhorn system are listed on Fig 4-1. Input for this selection uses current pipeline data compiled and maintained by the pipeline operator. The relevant data is listed in Appendix D – ORA Data List. The procedure will allow for adjustments to the segmentation if new ILI trap installations are made to the current system.

The procedure directs the analysis to the calculation of POE for each unrepaired anomaly reported in the ILI data. The output of this process is an investigation report that identifies anomalies that have a POE equal to or greater than 1×10^{-7}. The POE for depth (POE_D) is the probability that an anomaly is deeper than 80% of wall thickness. The POE for pressure (POE_P) is the probability that the calculated burst pressure of the anomaly will be less that the system operating pressure (MOP) or surge pressure (MASP).



<u>Note</u>:

(1) Main sections include:

- New 20” line from Galena Park to valve J-1
- 20” line from valve J-1 to Satsuma
- 18” line from Satsuma to Kemper
- 18” line from Kemper to Crane
- New 8” line from Crane to Odessa
- New 18” line from Crane to El Paso
- New 8” laterals from El Paso (2)
- New 12” lateral from El Paso

Figure 4-1

Top-Level Procedure for Determining Intervention Time for Corrosion

The final step using ILI data divides the assessment into calculating the intervention interval based on modeling corrosion growth using previous ILI data. The corrosion rates are determined by comparing previous ILI data with the current ILI data.

The appropriate procedures are followed to determine recommended intervention intervals for assessment of the line pipe integrity. Recommendations developed from these procedures are subsequently integrated with the recommendations developed from other ORA tasks (e.g. ILI recommendations for pressure cycle induced fatigue cracking and HCA regulation compliance) as described in Section 11, Integration of Intervention Requirements and Recommendations.

4.3 Procedure to Determine POE_D and POE_P for each Anomaly from Current ILI Data

The procedure is based on Section 3.5.2 of the LMP, ILI and Rehabilitation Program and the processes described in that section, and KAI Final Report No. 06-92 for girth weld anomalies and metal loss near girth welds,. The LMP requires that the following must be investigated within 6 months after the ILI Final Inspection Report is issued:

- Metal loss greater than 70% of nominal wall thickness
- Dents between the 4 and 8 o'clock positions with any indicated metal loss
- Any significant metal loss anomaly that threatens line pipe integrity and/or where the remaining strength of the pipe results in a safe operating pressure less than the current MOP. This is to be calculated using a suitable assessment criterion such as ASME B31.G, modified ASME B31.G, RSTRENG or LAPA.
- Gouges or grooves greater than 50% of nominal wall thickness
- Preferential corrosion, of or along seam welds, regardless of depth
- Any metal loss anomalies either side of girth welds or across a girth weld, regardless of depth using appropriate circumferential analysis techniques such as Miller's equation.
- Girth weld anomalies
- Casing shorts with associated metal loss.

Mitigation action, if necessary, will occur after evaluation by excavation.

Routine maintenance activities will investigate and repair as necessary the following upon discovery, which are in addition to the above:

- Dents with associated metal loss regardless of clock position
- Corrosion exceeding 12.5% of nominal wall thickness and within 0.5 inches of either side of the longitudinal seam or girth weld
- Any indication with associated metal loss (gouges, scratches, third party damage, and the like)
- Severe mill related defects (lamination, hard spots, etc.)

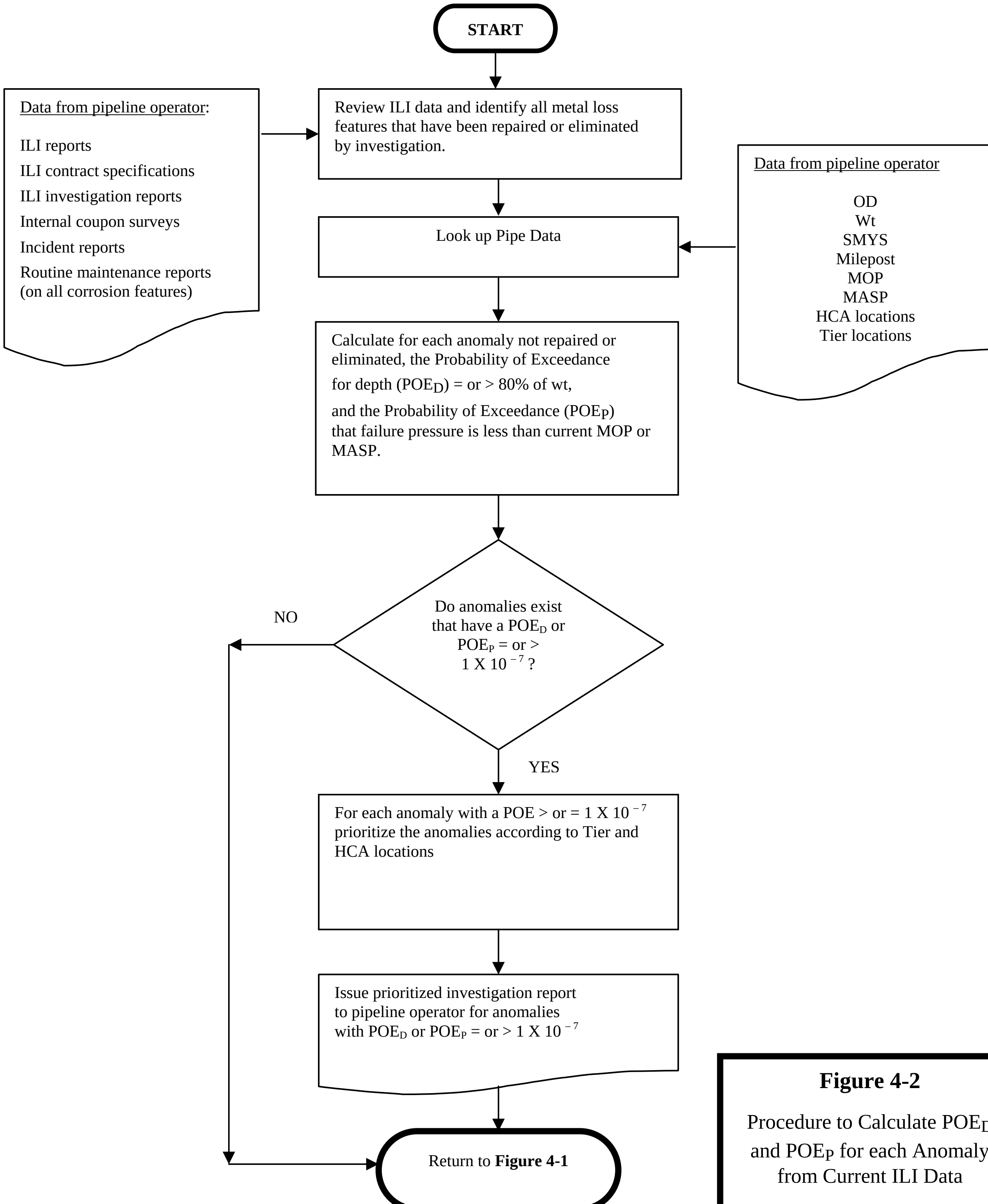


Figure 4-2

Procedure to Calculate POE_D and POE_P for each Anomaly from Current ILI Data

This ORA process takes in account the above investigations and repair actions and is based on the following:

- Reviewing the ILI vendor Final Inspection Report and any qualifying information
- Reviewing investigation reports from the pipeline operator based on the ILI report(s) to quantify the ILI findings and to identify which anomalies have been eliminated, repaired or will be repaired by these investigations. This ORA procedure will not include those anomalies that have been repaired, or are to be repaired, or have been determined by the operator investigation to not be associated with metal loss.
- Analyzing ILI based excavation data to determine the depth and RPRor pressure accuracy of the reported metal loss versus actual in-situ measurements
- Reviewing incident reports associated with metal loss
- Reviewing routine maintenance reports of metal loss investigations and any root cause analysis reports carried out by the pipeline operator
- Identifying any uninvestigated metal loss features in the ILI Final Report or qualifying statements that should be eliminated by investigation due to potential failure at MOP, MASP, or less.
- The metal loss anomalies will be prioritized according to Tier and HCA locations.
- An investigation report containing the prioritized listing is issued to the pipeline operator.

4.3.1 Calculation Procedures for POE using ILI Data

The calculation that the probability of a metal loss anomaly exceeds a depth of 80% of wt or has a burst pressure less than the current MOP or MASP will be based on the ILI vendor's inspection specifications. This will state the ILI tool depth tolerance specifications taking into account the post-run processing and data analysis. These tolerances will be modified if a review of investigation data on actual anomalies indicates that smaller or larger tolerances should be used.

The calculation for POE_D and POE_P will be performed on all metal loss anomalies in the ILI final report after removing all anomalies that have been investigated and repaired by the pipeline operator.

Probability of an Anomaly Exceeding 80% of Nominal Wall Thickness (POE_D)

The input values to the calculation for POE_D are:

- The depth for each remaining metal loss anomaly, including identified manufacturing faults, will be based on ILI measurements.
- The % tolerance on depth measurement as specified by ILI vendors
- A calculation of the % tolerance on depth measurement at an appropriate confidence level such as the 80%, 95%, or other level, derived from plotting and analyzing vendor predicted anomaly depths against actual anomaly depths measured from investigated features for which there is ILI data
- The exceedance threshold of 80% of nominal wall thickness.

The calculation assumes that the ILI tool measurement of maximum % depth is described by a normal distribution with a mean value equal to the reported peak depth and a standard deviation derived from the measurement tolerance at an appropriate confidence level. The tolerance used will be either that derived from vendor-supplied information or that calculated from comparing predicted depths with those measured from actual anomalies. The latter is preferred, but requires sufficient data to derive a statistically meaningful result.

The output from the calculation will be a list of anomalies whose probability of exceeding 80% of nominal wall thickness is equal to or greater than 1×10^{-7}. The location of these anomalies will be referenced to the ILI odometer and joint reference information together with station, milepost, Tier and HCA data provided by the pipeline operator.

Probability of an Anomaly having a Burst Pressure Less Than the MOP or MASP (POE_P)

The input values to the calculation for POE_P are:

- The % depth (or % depths for effective area calculations) for each remaining metal loss anomaly including identified manufacturing faults will be based on ILI measurements
- The % tolerance on depth measurement as specified by ILI vendors
- The length (or axial distance between depth measurements for effective area calculations) for each remaining anomaly as reported by the ILI vendor will be used
- A calculation of the % tolerance on depth measurement and/or pressure/RPR measurement at an appropriate confidence level, such as the 80%, 95%, or other level, derived from plotting and analyzing vendor predicted anomaly measurements against actual anomaly measurements from investigated features for which there is ILI data
- Pressure/RPR calculations will use the same methodology to calculate burst pressure for both the ILI and in-ditch investigated features

- The maximum length for the external and internal potential corrosion anomalies will be used if a two parameter burst pressure calculation is used such as B31.G or modified B31.G. The spacing of the depth measurements will be used if an effective area calculation is used such as RSTRENG or LAPA.
- The OD, wt, SMYS, current MOP and MASP for the line pipe with ILI data will be used
- The exceedance threshold of MOP or MASP applicable to each anomaly will be used.

The burst pressure will be calculated for each anomaly using the above input values and an appropriate calculation procedure such as B31.G, modified B31.G, RSTRENG, or LAPA unless superseded by other methods as discussed in Section 1.55, Incorporation of New Technologies and Processes. RPR will be calculated by dividing the calculated burst pressure by MOP or MASP as applicable to each anomaly.

The output from the calculation will be a list of anomalies where the probability that the strength of the remaining wall thickness being less than the MOP or MASP in which the anomaly has been detected is equal to or greater than 1×10^{-7}. The location of these anomalies will be referenced to the ILI odometer and joint reference information together with station, milepost, Tier, and HCA data provided by the pipeline operator.

4.4 Procedure to Determine Intervention Interval Based on ILI Data and ILI-Based Corrosion Rates

This procedure is shown in **Figure 4-3**. The procedure is based on Section 3.5.2 of the LMP, ILI and Rehabilitation Program, and the processes described in Section 4.5 above.

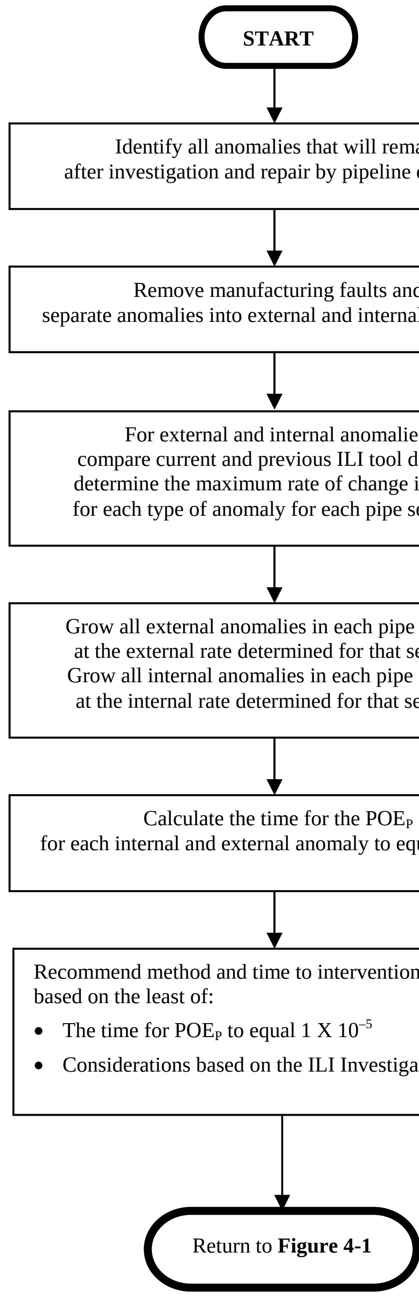


Figure 4-3

Procedure to Determine Intervention Interval Based on ILI Corrosion Rate

This ORA process to determine the intervention interval using corrosion rates from ILI data is based on the following:

- Completing the POE_D and POE_P calculations for each anomaly reported in the current ILI data
- Reviewing investigation reports from the pipeline operator based on anomalies with calculated POE_D or POE_P values equal to or greater than 1×10^{-7}. This ORA procedure will not include those anomalies that have been repaired, or are to be repaired, or have been determined by the operator investigation to not be due to metal loss.
- Removing manufacturing faults identified in the ILI Report by the inspection tool vendor from the anomaly listing. Manufacturing faults are not corrosion or TPD anomalies and do not have a time dependent growth mechanism.
- Separating the remaining non-injurious anomalies into internal and external anomalies so that different corrosion rates may be applied
- Comparing the current and previous ILI data into appropriate segment lengths and determining the maximum rate of change in metal loss depth for each segment
- To calculate the time to intervention (when the POE_P equals 1×10^{-5}) it is only necessary to grow the one remaining, unrepaired external and internal anomaly with the highest POE_P after all investigations and repairs have been completed. However, the process will calculate the time for each anomaly to reach a POE_P of 1×10^{-5} so that the operator may develop a practical approach to intervention based on the number and distribution of anomalies that can exceed 1×10^{-5} within a given timeframe.
- For all unrepaired external and internal anomalies, the measured corrosion rate for each anomaly, based on ILI data, will be used to calculate the time for each POE_P to reach 1×10^{-5}.
- All internal and external anomalies will be grown by the model until the POE_P is equal to 1×10^{-5}. The time taken for each anomaly to reach 1×10^{-5} will be determined.
- The internal and external anomalies will be prioritized according to Tier and HCA locations.
- The time to intervention for carrying out a further ILI inspection will be determined as the time taken for the first anomaly to have a POE_P equal to 1×10^{-5}. If a small number of anomalies with a POE_P approaching 1×10^{-5} are clustered over a short time interval, investigation and repair action may be recommended to remove all of these anomalies at one time.

4.4.1 Calculation Procedures for POE using ILI Data and ILI- Based Corrosion Rates

The calculation that the probability of a metal loss anomaly having a burst pressure less than the current MOP or MASP will be based on the ILI vendor's established inspection specification, modified if appropriate by using investigation results, and a separate corrosion rate for internal and external anomalies on a pipe joint basis.

The calculation for POE_P with growth through the wall thickness will be performed on all anomalies in the ILI final report after removing all anomalies that have been investigated and repaired by the pipeline operator. Repaired anomalies will include those that have been investigated, assessed and re-coated such that further corrosion has been reduced to a negligible rate.

Calculation of Time Interval for an Anomaly POE_P to Grow to 1 x 10^{-5}

The input values to the calculation for POE_P are:

- The maximum % depth (or the % depths if using an effective area technique) for each remaining metal loss anomaly, excluding identified manufacturing faults, will be based on actual ILI data
- The maximum length (or the axial distance between depth measurements if using an effective area technique) for each remaining anomaly as reported by the ILI vendor will be used
- The % tolerance on depth measurement as specified by ILI vendors
- A calculation of the % tolerance on depth or RPR measurements at an appropriate confidence level derived from plotting and analyzing vendor predicted anomaly depths or RPRs against actual anomaly depths or RPRs measured from investigated features for which there is ILI data
- The OD, wt, SMYS, current MOP and MASP for the line pipe with ILI data will be used
- The MOP or MASP applicable to each anomaly will be used.

The burst pressure will be calculated for each anomaly using the above input values and an appropriate calculation procedure such as B31.G, modified B31.G, RSTRENG, or LAPA unless superseded by other methods as discussed in Section 1.55, Incorporation of New Technologies and Processes.

The output from the calculation will be a probability that the strength of the remaining wall thickness is less than the MOP or MASP for either of the external or internal potential corrosion anomalies. If this is equal to or greater than 1 x 10^{-7}, a report will be issued to the pipeline operator specifying required pipe inspections.

ILI Determined Corrosion Rates

The use of repeat ILI inspection data allows corrosion rates to be determined on a location-by-location basis. This data can be used to implement control measures at those locations that need it, which could result in lower rates used to establish the intervention interval. For locations that show no measurable change, it supports the conclusion that the current corrosion control measures are adequate.

Determination of External And Internal Corrosion Rates

The current and previous ILI data will be reviewed on a joint-by-joint basis for those anomalies that have not been investigated and/or repaired. The data will be filtered using information from the pipeline operator as to the exact location and extent of the repairs carried out on the pipeline segment at the time the ORA process is carried out.

To allow flexibility, this ORA process will use the following procedure for both external and internal corrosion rates determined using ILI data:

1. ILI vendor supplied growth information will be used where applicable.
2. The maximum change in depth will be determined for each pipe joint for external and internal anomalies when no ILI vendor supplied information is available.

The above procedure will apply corrosion rates that will be location specific. Applying the calculated external rate can be justified on the basis that the change observed for that anomaly reflects the local environment, coating condition and CP effectiveness. The same argument can be used for internal anomalies.

Calculation Output

The output from the calculations will be a list of external and internal anomalies with the time interval to reach a POE_P value of 1×10^{-5}. The location of these anomalies will be referenced to the ILI odometer and joint reference information together with station, milepost, Tier and HCA data provided by the pipeline operator.

4.4.2 Determination of the Intervention Requirements Using ILI Data and ILI-Based Corrosion Rates

Timing

The ILI data will be used to remove any metal loss flaws that could impact line pipe integrity. The assessment of any corrosion anomalies that remain and could grow to failure will be based on the POE_P. The intervention time will be determined as the calculated time for the remaining anomaly with the greatest POE_P value to reach 1×10^{-5}.

The ORA process following an ILI will take into account relevant Incident reports, routine maintenance reports, and root cause analysis reports from the pipeline operator. These data sources will be reviewed to identify any evidence of corrosion and compare to its corresponding ILI data and calculated corrosion rates. If the data were reasonably comparable, no changes to inspection interval and type would be warranted. Under some special circumstances, data from relevant reports may warrant a revised intervention plan than determined by the POE_P analysis described above.

Method

The intervention method will be recommended taking into account all of the following:

- The continued use of an ILI corrosion tool
- A review and evaluation of alternative and appropriate methods that would satisfy the requirement to maintain line pipe integrity from a corrosion perspective.

4.5 References

1. The Longhorn Mitigation Plan (Revised) RAD 38851, September 11, 2000.
2. Kiefner, J.F., Johnston, D.C. and Kolovich, C.E., "Longhorn Partners Pipeline, L.P., Mock Operational Reliability Assessment, October 16, 2000."
3. Johnston, D.C. and Kolovich, C.E., "Using A Probability Approach to Rank In-Line Inspection Anomalies for Excavation and for Setting Reinspection Intervals." API 51st Annual Pipeline Conference & Cybernetics Symposium. April 18-20 2000.