Magellan Pipeline Company

Final Report No. 13-016

Final Report

2011 Operational Reliability Assessment of the Longhorn Pipeline System

Harvey Haines, Carolyn Kolovich, and Dennis Johnston

January 21, 2013

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on

2011 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

January 21, 2013

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 or LMP 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.

Accident – as stated in the LMP, an undesired event that results in harm to people or damage to property

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.

D – pipe diameter, usually the outside diameter of the pipeline (also see, OD).

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:

Commercially navigable waterway
High population area
Other populated area
Unusually sensitive area (USA)

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 – An event defined in the Incident Investigation Program of the LMP: Includes accidents, near miss cases, or repairs, and/or any combination thereof. Incidents 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.

Near Miss – An event defined in the Incident Investigation Program of the LMP as an undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property. In addition the LMP states: a specific scenario of a minor accident (minor actual loss) could also be a major near miss (major potential loss). Thus a near miss may or may not result in an incident.

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. In 2010 a 7-mile loop (3 ½ miles each way) was added, connecting Magellan's East Houston terminal to MP 6.

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.

Repair – The LMP describes a repair as a temporary or permanent alteration made to the pipeline or its affiliated components that are intended to restore the allowable operating pressure capability or to correct a deficiency or possible breach in mechanical integrity of the asset.

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 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.

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2011 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 2011 operating year. Kiefner and Associates, Inc. (Kiefner) 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 Kiefner 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 April, 2011. Additional guidance for the ORA is provided by the "Mock ORA for Longhorn Pipeline" that was performed by Kiefner 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:

1. Pressure-Cycle-Induced Fatigue
2. Corrosion
3. Laminations and Hydrogen Blisters
4. Earth Movement and Water Forces
5. Third-Party Damage
6. Stress-Corrosion Cracking
7. Threats to 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:

1. Corrosion Management Plan
2. In-Line Inspection and Rehabilitation Program
3. Key Risk Areas Identification and Assessment
4. Damage Prevention Program
5. Encroachment Procedures
6. Incident Investigation Program
7. Management of Change
8. Depth of Cover Program
9. Fatigue Analysis & Monitoring Program
10. Scenario Based Risk Mitigation Analysis
11. Incorrect Operations Mitigation
12. 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 701 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, Arizona, and Mexico. 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. In 2010 Magellan added a 7-mile long 20-inch diameter loop (3½ miles each way) between the Longhorn Pipeline near MP 6 to a tank farm at East Houston Station.

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 and 2010. 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 East Houston Station (6½ miles upstream of MP 9.1) to Crane (MP 457.5). Pipelines outside of this interval are considered New Pipeline extensions and are not subject to the specific requirements that are applied to the Existing Pipeline (Valve J-1 to Crane), although there are subject to all PHMSA regulations and other commitments in the LMP.

Time Scope

This report presents the annual assessment for 2011 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 2011 annual ORA report of the Longhorn system assets addresses the following subjects:

- Threats and Potential Threats to the Pipeline
    1. Pressure-Cycle-Induced Fatigue
    2. Corrosion
    3. Laminations and Hydrogen Blisters
    4. Earth Movement and Water Forces

5. Third-Party Damage
6. Stress-Corrosion Cracking
7. 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 2054. 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 periodically 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. Results show no immediate digs were required and a substantially smaller number of required repairs for scheduled and POE digs. In addition, the second MFL tool run for Crane to Odessa was completed in June 2011 initiating the second sequence of ILI tool runs for the New Pipeline extensions not covered under commitments LMC 10, 11, 12, & 12A.

The condition of any laminations and blisters using UT ILI data was completed on the existing pipeline from Galena Park to Crane in 6 segments. From 8,183 laminations identified in these six segments, 82 excavations were selected and 2 possible bulging laminations were discovered and repaired with Type B pressure containing sleeves.

From the standpoint of earth movement, the primary integrity concerns are soil erosion and scouring from floods and ground movement from aseismic faults at specific points along the pipeline. Scour surveys of the crossings at the Colorado River and its tributary Pin Oak Creek are starting to show some evidence of soil erosion or scouring. These surveys need to be related to the remaining amount of cover for these two pipelines. Appropriate surveys were apparently performed in 2012 and will be reported upon in the 2012 ORA. The remaining river crossings were inspected in 2010, as part of their 5-year reinspection requirement. As of 2011, 7 years of data of aseismic fault movements have been taken. The results show fault movement on three of the faults continues to be so small that ground movement will not be a threat to 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. However, four near misses occurred and were caused by one third-party who did not use the One-Call system and 3 third parties who did not follow One-Call procedures after the pipeline was identified. Two near misses resulted in contact with the pipeline and were categorized as minor incidents. The damaged areas were inspected and recoated. An internal Magellan recommendation has been made to erect temporary fencing for improvement in preventing damage to the pipeline once an encroachment location has been identified.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. Magellan continues to carry out inspections as part of the normal dig program by performing an SCC examination program that uses magnetic particle testing at each dig site.

From the standpoint of facilities data acquired in 2011, one can conclude that pump station and terminal facilities had no adverse impact on 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 in the total number of miles patrolled. 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 where necessary. From the standpoint of deterioration measures, the number of anomalies found per mile requiring excavation decreased substantially between the MFL runs and the UT ILI runs. The number of anomalies requiring immediate repair was zero for the UT ILI runs, down from 0.02-0.04 anomalies per mile for the first MFL runs completed after the line was restarted. In terms of failure measures, there were 2 DOT-reportable incidents and there were 2 instances of known third-party contact with the pipe.

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

Internal corrosion coupons are used to monitor internal corrosion and the cathodic protection system is monitored to look for areas where external corrosion could be occurring. The corrosion management plan in combination with the ILI program has been effective at preventing corrosion degradation in 2011.

In-Line-Inspection and Rehabilitation Program

UT inspections for the Existing Pipeline were completed in 2010. Remediation was completed on two sections in 2010 and the remaining six sections were completed in 2011. One additional MFL inspection was completed in 2011 on the Crane to Odessa Lateral. The ILI surveys have been effective and have shown a decrease in the number of required repairs and thus an improvement in the condition of the pipe between the first set of MFL runs and the most recent UT runs.

Damage Prevention Program

The absence of reportable incidents involving mainline pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended. However the existence of two instances of third party contact with the pipe indicates additional measures may be warranted. Near misses are defined as events that could have resulted in something much more severe. Incident reports associated with 2 of the 4 near misses described the results as minor non-reportable incidents though contact was made with the pipe and thus one of the Magellan incident reports made a recommendation that temporary fencing is to be used to help prevent contact with the pipe in the future. Because these near misses could have been much worse, we concur with this recommendation when excavation work is occurring in an area of authorized encroachment.

Encroachment Procedures

There were 76 encroachments recorded in 2011, and according to the Annual TPD report none of which were unauthorized. One near miss at MP 533.16 was attributed to hand excavation by a third party contractor to locate the pipeline and was not an authorized encroachment. Because this excavation was performed by hand it is not a violation of the Texas One-Call and is also not an unauthorized encroachment. Encroachments such as this which are neither an authorized nor unauthorized encroachment should be accounted for in future encroachment reports, incident investigations, and the Annual TPD report.

Incident Investigation Program

Magellan is performing incident investigations on all DOT reportable incidents and on many more non-reportable incidents. Four non-DOT reportable incidents related to the TPD prevention program and 5 incidents related to facilities were reviewed. One of the facilities incidents was DOT-reportable. Kiefner finds these incident investigations sufficient in most cases; however there was one TPD One-Call violation where Magellan did not state whether encroachment procedures had been followed resulting in uncertainty in the Annual TPD report about no unauthorized encroachments. Although this program is effective in helping Magellan determine the root cause of incidents on the pipeline in an effort to prevent future incidents, we recommend adding some form of encroachment analysis to assist in future analysis for the TPD Annual Report.

Depth of Cover Program

A Depth of Cover (DOC) survey was last performed in 2007. No new repairs were reported in 2011.

Fatigue Analysis and Monitoring Program

The 2011 fatigue analysis performed by Kiefner 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 2054 was calculated based on the pressure cycles for 2008 through 2011 and using the results from the 2007-2008 TFI tool runs.

Corrosion

For the threat of corrosion, UT inspections for the Existing Pipeline were completed in 2010. Remediations were completed on two sections in 2010 and the remaining six sections were completed in 2011.

Laminations and Hydrogen Blisters

Thirty-two lamination anomalies were excavated and evaluated during 2011 on the original pipeline segments. The laminations excavated and evaluated were predicted to be sloping laminations (19), bulging laminations (11), or corrosion with a lamination (2). The nondestructive testing reports indicated possible bulging on 2 of the 11 predicted bulging laminations. These anomalies were repaired with a pressure containing sleeve. The remaining laminations were determined to be mid-wall. Magellan should continue to monitor the lamination locations with ILI tools to verify that no blisters are forming. The monitoring frequency recommended should coincide with the metal loss reassessment schedule in Section 7.

Earth Movement and Water Forces

The earth-movement analysis continues to show that any movement on the four faults that are monitored is an order of magnitude less than the assumptions used to justify the required monitoring program in the EA. Kiefner continues to recommend a five year reinspection program for these four faults rather than the current 6 month program. If the faults appear to become more active, then more frequent measurements can be implemented.

Inspections showed signs of some erosion or scour damage at stream crossings from storm water flooding. This erosion needs to be related to the remaining depth of burial on the pipeline so that Magellan can plan for any remediation that may be needed once an erosion threshold is reached. (see Stream Crossings in Section 5.4) 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 2011. 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 in 2009-2010. LMC 12A requires inspections with a "smart" geometry tool be carried out within three years of a previous inspection. These inspections have been 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 8 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 2011.

3.3 Implementation of New Mechanical Integrity Technologies

No new technologies were implemented in 2011.

3.4 ORA Process Improvements

No new processes were implemented in 2011.

4. New Data Used in This Analysis

The ORA Process Manual identifies 78 items in Appendix D consisting of data, data logs, and reports the ORA contractor must review and consider in conducting the ORA. These 78 items in the ORAPM are 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 and 2010 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 (East Houston to MP 9, 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. 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. 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.

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 accordance 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 and 2010 pipe material is the same as that described above for the 1950 pipe material.

Our analysis shows that the shortest time to failure for a possible feature that could have been missed by the TFI tool is 106.3 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 47.8 years based on the current operating pressures. An assessment would be required in 2054 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 and the 2010 pipe material for the East Houston loop 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	2010 ERW pipe at East Houston	3.5 miles from Mainline	-	20	0.250	X52
Case 3	Transition to 1950 ERW pipe at MP9 downstream of Galena Park	480+09	9.1	20	0.312	Grade B
Case 4	Transition to heavy wall 1950 EFW pipe	1067+46	20.2	20	0.375	Grade B
Case 5	1950 EFW pipe at Satsuma	1802+61	34.1	18	0.281	X45
Case 6	Transition to heavy wall 1950 EFW pipe	1821+42	34.5	18	0.375	Grade B
Case 7	1950 EFW pipe downstream of Cedar Valley	10037+72	190.1	18	0.312	X45
Case 8	1950 EFW pipe at Kimble County	15589+07	295.2	18	0.281	X45
Case 9	Transition to 1950 ERW pipe at Kemper (former Exxon Station)	21387+88	405.1	18	0.25	X52
Case 10	1998 ERW pipe at Crane	24158+39	457.5	18	0.281	X65

Table 2 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, no feature greater than 10-percent of the wall thickness existing in the new pipe 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	> 500	> 225	2010	> 2225
Case 3	487.3	219.3	2007	2226.3
Case 4	> 500	> 225	2007	> 2225
Case 5	123.5	55.6	2007	2062.6
Case 6	383.7	174.5	2007	2181.5
Case 7	130.3	58.6	2007	2065.6
Case 8	***106.3***	***47.8***	***2007***	***2054.8***
Case 9	> 500	> 225	2008	> 2233
Case 10	> 500	> 225	1998	> 2223

5.2 Corrosion

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 and size corrosion features followed by remediation of features that exceed a depth or a pressure threshold as necessary. This generally accepted method is a valid approach for addressing line pipe corrosion.

UT ILI Inspections

Ultrasonic wall measurement tools were run on the six pipeline segments from Galena Park through Crane beginning in 2009 with completion in 2010. The UT tools provided information on internal and external metal loss, as well as geometrical anomalies such as dents, and also provided information on the existence of laminations and inclusions. The following metal loss anomalies were addressed in 2011 by pipeline segments:

Table 3. Summary of Metal Loss Anomalies Excavated

Pipeline Segment	Metal Loss Anomalies Excavated
Galena Park to Satsuma	0
Satsuma to Warda	17
Warda to Cedar Valley	21
Cedar Valley to Eckert	0
Eckert to Fort McKavett	40
Fort McKavett to Crane	43

Corrosion Growth Analysis

An independent analysis of the correlation of multiple ILI run data and excavation data was performed by Quest Integrity Group. The report was reviewed by Kiefner and the conclusions appear to be appropriate. The analysis determined that an external corrosion growth rate of 5 mils per year (the 95-percent upper bound) is appropriate for use on the Longhorn Pipeline System. An internal corrosion growth rate of 1 mil per year due to a lack of evidence of overall internal metal loss growth is appropriate.

5.3 Pipe Laminations and Hydrogen Blistering

An ultrasonic wall measurement tool was run in each of the six segments between Galena Park and Crane to detect laminations and to determine if any of the laminations had developed blistering due to adsorption of hydrogen. One thousand, six hundred and ninety-five (1,695) laminations were detected on the Galena Park to Satsuma segment and 1,082 laminations were detected on the Satsuma to Warda segment, 541 laminations were detected on the Warda to Cedar Valley segment, 594 laminations were detected on the Cedar Valley to Eckert segment, 1,907 laminations were detected on the Eckert to Fort McKavett segment, and 2,364 laminations were detected on the Fort McKavett segment. During the 2010 and 2011 remediation program, 22 lamination excavations were performed on the Galena Park to Satsuma segment, 24 lamination excavations were performed on the Satsuma to Warda segment, 6 lamination excavations were performed on the Warda to Cedar Valley segment, 27 lamination excavations were performed on the Eckert to Fort McKavett segment, and 33 lamination excavations were performed on the Fort McKavett to Crane segment. Only 2 of the excavations discovered possible bulging laminations. These areas were repaired with Type B pressure containing sleeves. These results are summarized in **Table 4**.

Table 4. 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

Table 5. Summary of Laminations Detected and Excavated

Pipeline Segment	Laminations Predicted from ILI	Laminations Excavated
Galena Park to Satsuma	1,695	22
Satsuma to Warda	1,082	24
Warda to Cedar Valley	541	6
Cedar Valley to Eckert	594	0
Eckert to Fort McKavett	1,907	27
Fort McKavett to Crane	2,364	33

The probability of pipe laminations adversely affecting the pipe laminations is low due to the refined products transported by the Longhorn pipeline. The most likely risk factor for blister development would be adversely high cathodic protection potentials applied to the pipeline. No instances of abnormally high potentials were found during the assessment.

Planned conversion of the pipeline to crude oil service will re-introduce hydrogen sulfide to the pipeline, similar to the crude oil that was transported from the early 1950's until 1995. Monitoring of the lamination anomalies for the possibility of blister growth with ILI tools is recommended per the proposed Longhorn Pipeline Reversal Section 6.2.1.2.

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 6.

Table 6. 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. Thirteen 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 7½ 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 0.09 inch (2.2 mm) over 7½ years for the Akron fault and -0.11 inch (-2.7 mm) over 7½ years for the Hockley fault.

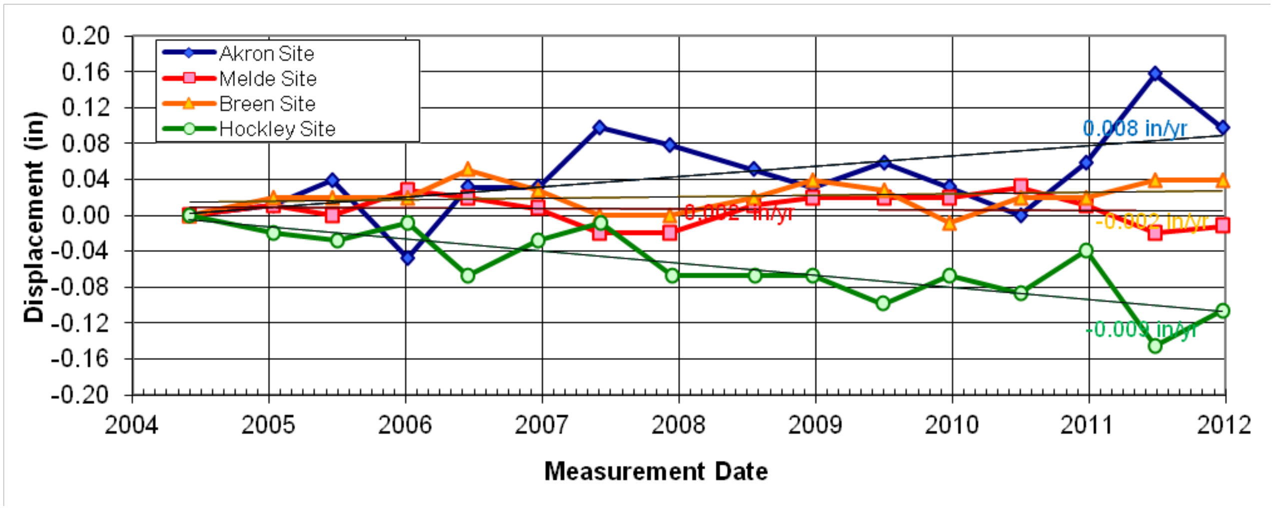

Figure 1. Fault Displacement Over 7½ Year Period

For this year's analysis with 7½ years of data, we used the calculated movement from the best fit trend lines and compared these estimates of fault growth to the Kiefner stress analysis described in the 2005 ORA Annual Report. Table 7 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. Because the calculated rate of displacement has not changed the number of years to reach the allowed displacement has not changed from the amount reported in the 2010 Annual Report.

Table 7. Summary of Estimated Allowable Fault Displacement Due to Stresses

	Displacement (in)	Years to Reach Displacement
Akron	4.17	521
Melde	4.13	> 1000
Breen	1.50	750
Hockley	0.63	70

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 7 shows the amount of time it will take for stress levels to exceed those allowed by ASME B31.4.

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 7½ 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. We continue to believe the time to failure is large enough that semi-annual monitoring is much more often than needed.

Hockley fault monitoring is recommended every 5 years even though the estimated time to failure for the fault is 70 years. Because the accuracy of the fault movement measurements appears to be 0.4 – 0.8 in (1 - 2 mm), several measurements are needed over time to obtain a trend. The other three faults have reinspection times of over 500 years. Such long times to reach a displacement that could result in failure would normally not warrant any monitoring. However, according to the U.S. Geological Survey, September 2005[4] there are documented cases of fault movement reinitiating, so monitoring every five years for these 3 faults is also appropriate.

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 last inspected in June 2011. Results show changes in the High Bank to the Toes on Pin Oak Creek of 4-6 feet and changes between the Toes of the bank of the Colorado River of 7 feet and changes on the west Bank between Toe and High Bank of 4 feet. The other crossings were most recently inspected in 2010 as part of the 5 year Aerial Inspection and have no new data to analyze in 2011.

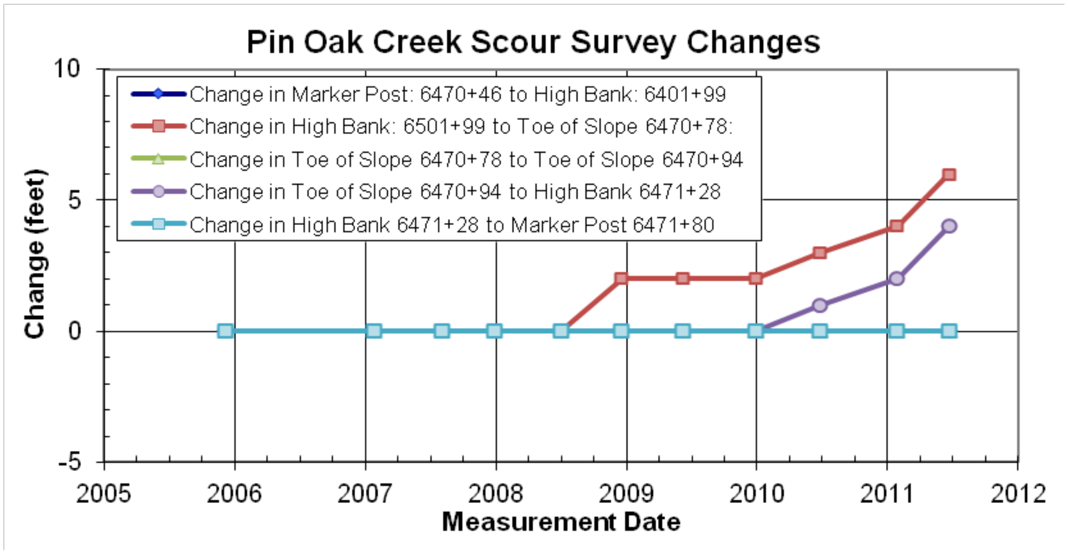

Figure 2. Changes in the Scour survey of Pin Oak Creek over 5 ½ years.

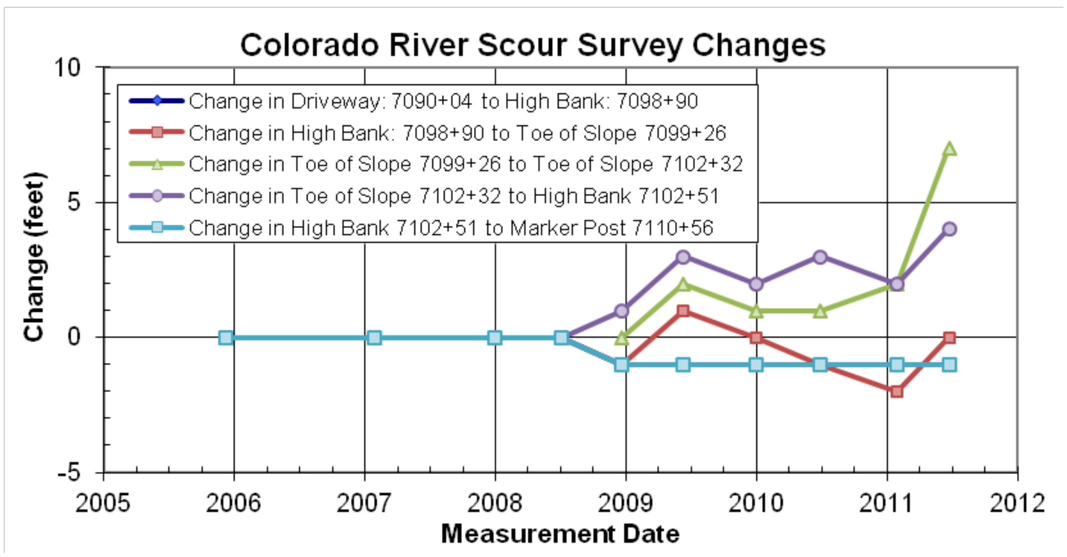

Figure 3. Changes in the Scour survey of the Colorado River over 5 ½ years.

These changes in the distance from the High Bank to the Toes of Pin Oak Creek and the distance between the Toes and the distance from the West High Bank to the Toe of the Colorado River are starting to become significant and may warrant a survey of the depth of burial of the pipeline below the Toes of the two bodies of water to determine how much depth of cover loss is acceptable.

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 2011 TPD Annual Assessment we conclude:

- There were 4 near misses reported.
  - o Of the 4 near misses, one appears to be an encroachment that was not required to be documented because it was not a One-Call violation and as a result was neither an authorized nor unauthorized encroachment.
  - o 2 of the 4 near misses in 2011were documented as hits to the pipeline, one damaged the coating by spinning wheels in the mud on top of the pipeline and the other during trenching operations while laying a conduit. This is the first documented contact to the pipeline since startup.

- There was 1 One-Call violation reported in 2011. This is fewer than any previous year except for 2006 where 0 One-Call violations occurred.
- The TPD Annual Assessment shows a 29-percent decline of unique aerial patrol observations, with a 52-percent drop in third-party activity or non-company aerial-patrol-observations.
- Total One-Call tickets as tabulated in the 2011 TPD Annual Assessment are up 6-percent from the total from 2010.

For further detail see Appendix B, Section 4.11 One-Call Violations and Third-Party Damage Prevention 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. No new repairs were implemented in 2011 as a result of this survey.

The UT survey results were examined for potential third party damage. ILI and maintenance reports documented one geometrical anomaly at MP 105.42 associated with metal loss that turned out to be mechanical damage. Although it is not uncommon for ILI tools to miss mechanical damage, because this is the third set of ILI tools run in the pipeline, mechanical damage found by ILI should be reconciled with previous runs by re-examining raw data from these earlier ILI runs. For mechanical damage to be found by ILI it must either have been missed by previous ILI runs or have been a recent hit to the pipeline. A review of previous ILI vendor reports did not indicate an anomaly at this location, however it could not be said for certain this was a recent hit to the pipeline, especially because of the aggressive above ground patrol monitoring that occurs. In response Magellan had the MFL vendor review both the previous MFL run and the aerial patrol data.

The aerial patrol observations did indicate some activity in the area, but it was correlated to known crossings. The MFL vendor did find a mechanical damage anomaly that was not reported because the measured depth of 1.8 percent deep fell below the reporting threshold. As a result it was clear that this anomaly found from the UT ILI run existed prior to the MFL ILI run. In the future an incident investigation needs to be performed for any new mechanical damage anomaly found by ILI to determine whether the anomaly is new and missed by above ground patrols or old and missed by previous ILI runs.

One-Call Violation Analysis

Out of 11,090 One-Calls in 2011, it appears that 10.1-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”, and the likely encroachments from the “no locates” (One-Call locations that are 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 two counties. Harris County accounted for 6,124 (55-percent) of the One-Call tickets. Travis County accounted for 1,485 (13-percent) of the One-Call tickets. Thus, fully 68-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 275 tickets (2.5-percent). Given that there was minor contact from two of the near misses on the pipeline, Kiefner agrees with a Magellan recommendation that temporary fencing should be used where appropriate for authorized encroachments into the ROW going forward.

Figure 2 below shows a flow chart analysis of the One-Calls. Out of 11,090 One-Calls, 4 resulted in a near miss to the pipeline. In addition, there was one case where a third-party did not, but should have used One-Call to notify Magellan of activity in the ROW resulting in a One-Call violation. Exemptions from using One-Call are allowed if the excavation is shallower than 16 inches and no mechanized equipment is used. The flow chart has been changed slightly from previous years to remove the term “near miss”. The LMP defines a near miss as an undesired event which, under slightly different circumstances, could have resulted in harm to people of damage to property. This is the first year where minor damage to the pipeline has occurred and classified as a near miss. 2 of the 4 near misses can be classified as “major” near misses and minor accidents as described in the LMP Section 3.5.6 subpart 5 on classifying incidents. The fact that two major near misses occurred indicates some additional prevention activity is warranted.

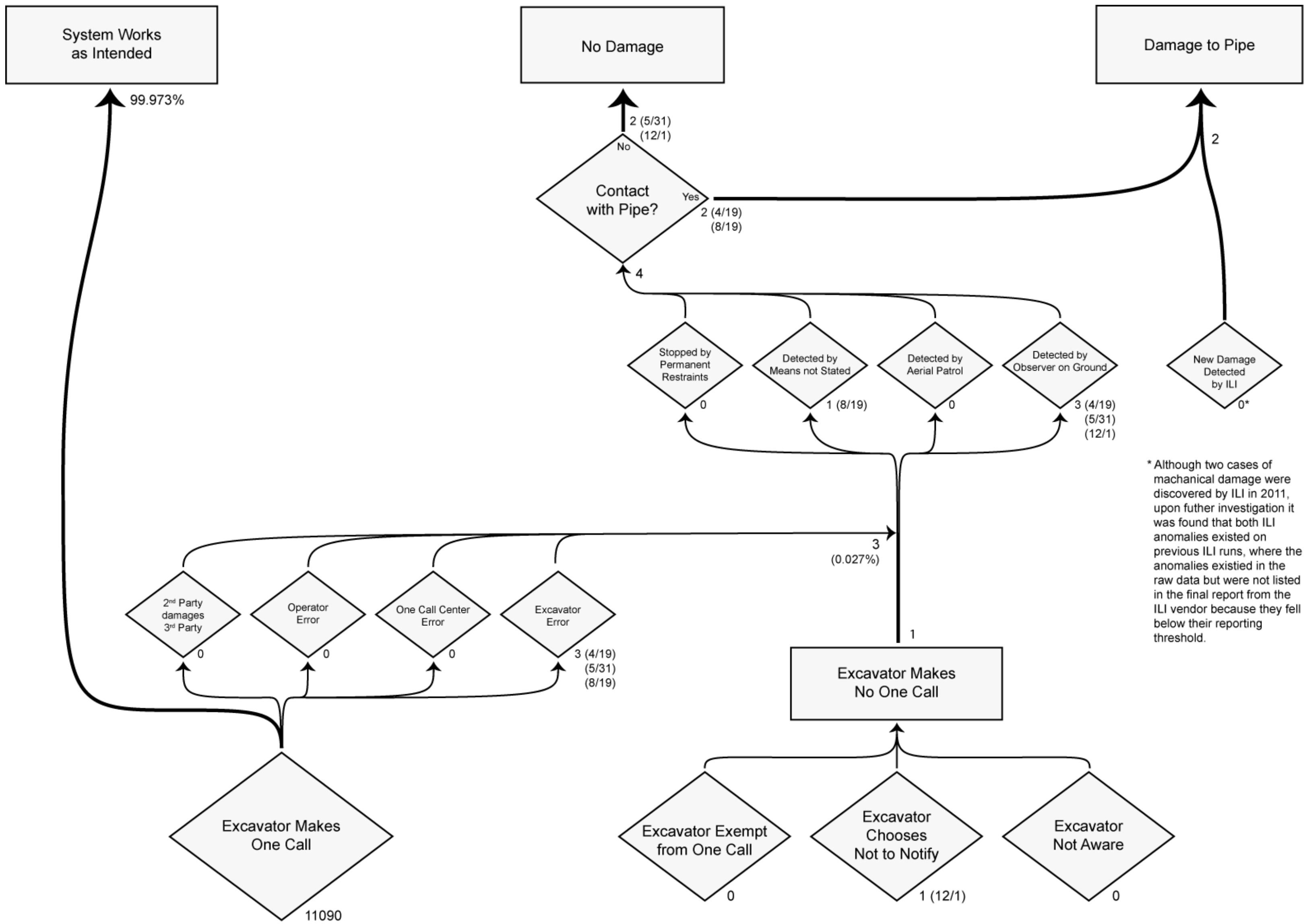

Figure 4. Flow Chart of 2011 One-Calls to the Longhorn System

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 2011, show that Magellan exceeded these requirements in terms of the total mileage patrolled required in order to meet the minimum requirements.

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. There was only a single One-Call violation during 2011. Therefore, there is no requirement to conduct an additional ILI inspection with a geometry tool at this time.

No additional direct examinations are recommended at this time.

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 2011, 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

Five facilities were subjected to a complete inspection addressing 115 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
- Mesa Valve Site
- Crane Pump Station
- El Paso Terminal
- Diamond Junction

Five incident data reports were received which concerned facilities in 2011, one of which was a DOT reportable incident (greater than 5 gallon spill volume). All of these incidents involved a spill of product caused by a pump pipe failure at Satsuma (2 gallons), a valve stem packing leak at Warda (99 gallons), and a filter leak at El Paso (less than 15 gallons).

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 a method 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 2011 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. The goal would be 100-percent of the commitment. Magellan met this commitment in 2011.

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 is no “passing grade”, 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 which 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 is no ”passing grade”, although a comparison of the results of this metric with sign placement, repair and replacement can be used to see if public education is being emphasized in the same geographic region where sign maintenance indicates problems. 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 of 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, there is no “passing grade”. However, this metric can be compared to encroachments allowing an overall measurement of how efficiently the One-Call process is being used.

Table 8. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010	2011
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	180,045	188,564
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	545*	475*	291	76
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17	36	34
No. 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	5,277	5,757
	Tier II	6,881	7,874	7,852	7,059	5,840	4,265	4,415
	Tier III	1,498	1,617	1,653	1,459	1,217	833	918

* 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 still a discernible trend downward in anomalies found per mile. The number of immediate corrosion anomalies predicted based on the reassessments had dropped to zero when compared to the initial corrosion assessments. This indicates that the excavation program is effective at reducing and actually eliminating the number of significant corrosion anomalies.

POE evaluations show a significant decrease of over an order of magnitude between 2005-2007 when the first in-line inspections for corrosion were performed to 2009-2010 when the second set of in-line inspections for corrosion were performed.

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

Table 9. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0	0	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	NA	0.0212	0.035	0.006	0	0	0
	Tier II	NA	0.0208	NA	NA	0	0	0
	Tier III	0.192	NA	0.003	NA	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA	NA	NA
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017	0.14	0.035

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 10. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011
Number of leaks (DOT reportable)		2	0	1	3	0	1	2
Average response time in hours for a product release.	Tier I	Immediate	NA	Immediate	Immediate	NA	Immediate	Immediate
	Tier II	NA	NA	NA	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA
Average product volume released per incident	Tier I	5.7 bbls	0	5.7 bbls	0.4 bbls	0	0.4 bbls	1.2 bbls
	Tier II	0	0	0	0	0	0	0
	Tier III	0	0	0	0	0	0	0
Total product vol. released in the 12-month period	Tier I	17 bbls	0	5.7 bbls	1.3 bbls	0	0.4 bbls	2.5 bbls
	Tier II	0	0	0	0	0	0	0
	Tier III	0	0	0	0	0	0	0
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50k	< $50k
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50k	< $25k
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	0	1	3	3	1	1
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0	0	2
Number of near misses to the pipeline by third parties		7	1	7	5	6	2	4
Number of service interruptions		115	165	155	74	16*	17	9

* 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 2009-2010 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 required Magellan to use an MFL tool for corrosion inspection in the first three months of operation, a TFI tool for seam inspection (which includes hook cracks and seam corrosion) 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 MFL 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.

Table 11a and 11b are a compilation of the tools run to date, and required reassessments as specified by the ORAPM. Reinspection requirements for pressure-cycle-fatigue crack growth reinspection intervals were extended based on the analysis performed in section 5.1 of this report. All other reinspection requirements have not changed from the 2010 ORA. Earth movement, the fifth component for threat integration, is not included in Table 9a or 9b because it is currently addressed using surface surveys rather than ILI technology. The *Aerial Inspection and Photo-Documentation of "Areas of Concern"* report conducted in 2010 for the threat of earth movement showed exposed pipe in a few areas. Between mile posts (MPs) 599.62 and 599.95 there appeared to be two sections of exposed pipe. The gully located at MP 668.33 shows an exposed portion of the pipeline. The 2010 ORA recommended that new exposures identified in the "Areas of Concern" report be integrated with the 2007 Depth of Cover investigation to determine if these exposures were new or warranted further investigations. The 2011 TPD Annual Report identified 11 new exposures, 1 exposure that was inspected in 2011 and was recommended for repair in 2012. The other 10 included: 9 that were inspected as part of the DOC program in prior years, and 1 that continues to be monitored.

Table 11a. 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***	***2200***		***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***	***2057***		***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***	***2162***		***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***	***2066***		***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***	***2048***		***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***	***2049***		***8-Jul-13***

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

** The MFL tool run in Dec-05 was used to complete the Oct-04 MFL 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 11b. Existing ILI Runs and Planned Future Inspections

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Pressure-Cycle Induced Fatigue	Laminations and Hydrogen Blisters	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
	HRMFL/Deformation	28-Jun-11	X			X
	Next Required Assessment		***28-Jun-16***	*Not susceptible*	*Not susceptible*	***28-Jun-16***
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 of 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. For the three new pipeline extensions the HCA requirement (49 CFR 195.452) requires 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 MFL-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 in the LMP 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.

Final tie in points were refined in the field and agreed to by Magellan and LCRA. 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 completed prior to startup (prior to June 10, 2002). Replacement of the other four segments was completed by January 26, 2012.

Other Pipe Replacements

None noted in 2011.

8. RECOMMENDED IMPROVEMENTS TO THE ORA PROCESS

Table 12. Summary of 2011 Recommendations

Topic	Recommendation	ORA Ref Page
Hydrogen Blistering	With the conversion of the pipeline back to crude oil service and the reintroduction of hydrogen sulfide, monitoring of the laminations anomalies for the possibility of blister growth with ILI tools is recommended per the EA of the proposed Longhorn Pipeline Reversal Section 6.2.1.2. These inspections should be coordinated with ILI runs for corrosion and mechanical damage.	15
Aseismic faults	We continue to 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	15-17
Stream Monitoring	Recorded changes in the distance from the High Bank to the Toes of Pin Oak Creek and the Colorado River warrant a survey of depth of burial of the pipeline near the toes of the banks of these two bodies of water.	18
Damage Prevention	The minor incidents where contact with the pipe was recorded indicate additional preventative actions are needed to ensure that no significant release will occur in the pipeline ROW. We concur with Magellan's own internal recommendation that the next step needs to include the use of temporary fencing where appropriate in areas where an encroachment agreement has been obtained. In addition we recommend that unauthorized encroachment needs to be added to the incident investigation form.	21
Aerial Patrol Documentation	Record keeping practices for aerial patrols have become less precise than in previous years and need some improvements. See the discussion for Item 56 Miles of Pipe Inspected by Aerial Survey by Month in Appendix B for details.	46

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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

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Appendix A: Mitigation Commitments

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 (MFL) 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, MFL, 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 regard 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)

Alignment sheets were received for the tie in to the Magellan tank farm in Houston.

Pump Stations (Item 15)

Facility diagrams were received for the tie in to the Magellan tank farm in Houston.

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, Kiefner received pressure and flow data for Galena Park, East Houston, 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 evaluations completed in 2011.

Table B-1a. Excavations Completed in 2011

Line Segment	18" Satsuma to Warda	18" Warda to Cedar Valley	18" Cedar Valley to Eckert	18" Eckert to Ft McKavett	18" Ft McKavett to Crane
ILI Date	11/24/2009	1/24/2010	2/20/2010	6/25/10	8/5/10
Maintenance Report	yes	yes		yes	yes
Tier 1	6	3	2	37	35
Tier 2	0	3	8	1	1
Tier3	0	0	0	1	5
Total Digs	6	6	10	39	41
HCA	1	5	4	9	0
Non-HCA	5	1	6	30	41

Table B-1b. Anomalies called that were addressed in the above Excavations

ILI Anomaly Called	Number of Anomalies Addressed	Satsuma to Warda	Warda to Cedar Valley	Cedar Valley to Eckert	Eckert to Ft McKavett	Ft McKavett to Crane
Ext Metal Loss	111	16	19	21	36	40
Int Metal Loss	3	1	1	0	1	0
Lamination Intermittent	20	0	0	0	9	11
Lamination Intermittent Associated With Metal Loss	2	0	1	0	1	0
Lamination Sloping	19	0	0	0	11	8
Lamination Variable Depth	2	0	0	0	1	1
Lamination Bulging	9	0	0	0	1	8
Lamination Bulging Intermittent	3	0	0	0	1	2
Lamination	6	0	0	0	3	3
ID Reduction - Sharp - Dent on Weld	3	0	0	0	3	0
ID Reduction L<1.5D	1	0	0	0	0	1
ID Reduction L>1.5D	1	0	0	0	0	1
ID Reduction on Weld	1	0	0	1	0	0
ID Reduction	2	0	0	2	0	0
Geometric Anomaly Associated With Metal Loss	4	0	0	0	2	2
Area Of Bulge	10	0	0	0	2	8
Surface Irregularity	11	0	0	0	9	2
Weld Irregularity	6	0	0	0	1	5
Ext Metal Loss Associated With Brc Dent	4	0	0	0	2	2
Ext Metal Loss Associated With Lamination	1	0	0	0	1	0
Ext Metal Loss Crosses Girth Weld	1	0	0	0	0	1
Ext Metal Loss Crosses Long Seam	1	0	1	0	0	0

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)

Based on the 2011 excavation reports, no confirmed blisters have been found on the original Longhorn segments. The maintenance reports classified the laminations as mid-wall without reference to separation.

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 2011.

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

See section 4.3 above.

External Corrosion Growth Rate Data (Item 36)

The UT data and the MFL data were correlated to determine external corrosion growth rates for anomalies detected by each tool. The observed growth rate averages 5 mils per year using the 95-percent upper bound, based on the 2011 study performed by Quest Integrity Group.

Internal Corrosion Coupon Results (Item 37)

Three internal corrosion coupon reports were reviewed for the 2011 annual report. Four lines were sampled with coupons placed in the 8-inch Odessa lateral at Crane, the Plains 8-inch lateral at El Paso, the 18-inch main line at El Paso, and the 20-inch line between Galena Park and East Houston at East Houston. Little to no corrosion was observed with measured corrosion rates all much less than 1 mil per year. The Quest Integrity Group did not find strong evidence of overall internal metal loss growth when they performed their ILI data comparisons. An internal corrosion growth rate of 1 mil per year is considered to be appropriate for ILI data.

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
12/30/2010	5/1/2011	122	0.00	None	None	
5/1/2011	9/1/2011	123	0.07	<5%	Light	
8/30/2011	12/30/2011	122	0.00	None	None	

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
1/3/2011	4/28/2011	115	0.00	None	None	
4/28/2011	8/31/2011	125	0.00	None	None	
8/31/2011	12/30/2011	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
1/3/2011	4/28/2011	115	0.00	None	None	
4/28/2011	8/31/2010	125	0.09	25% to 50%	Medium	
9/1/2011	12/31/2011	121	0.00	None	None	

Table B-2d. Internal Corrosion Coupon Results 20-inch Galena Park (6645) at Houston Terminal

Inserted	Removed	Exposure (days)	Rate (MPY)	Portion of Test Surface Rusted	Under Holder Attack	Comments
4/14/2011	9/13/2011	152	-0.02	None	None	
9/13/2011	12/30/2011	108	0.01	<5%	Light	

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)

No maintenance reports were received covering the fault crossings in 2011.

Periodic fault benchmark elevation data (Item 31)

Semi-Annual Fault Displacement Monitoring was performed June 24, 2011 and December 22, 2011 which covers semi-annual fault measurements at the four fault monitoring sites since inception in mid-2004 through December 2011.

Pipeline Maintenance Reports for Stream Crossings (no item number)

Scour reports were received for the two stream crossings, the Colorado River and its tributary Pin Oak Creek, which were last monitored June 21, 2011.

Flood Monitoring (no item number)

Flood monitoring spreadsheets were received for Colorado River, Pin Oak Creek, and the Pedernales River. None of these rivers exceeded flood stage in 2011.

4.7 Maintenance and Inspection Reports

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

No new surveys were made in 2011.

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

None found.

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	Ja n	Fe b	Ma r	Ap r	Ma y	Ju n	Ju l	Au g	Sep *	Oc t	No v	De c	Tota l
New	4	2	4	0	2	2	0	0	0	0	5	0	**19**
Close d	1	4	2*	1	1	0	0	0	3	0	3	0	**15**
Open at End of Month	3	1	3	2	2	4	4	4	1	1	3	3	

*1 closed action item appears to be a duplicate whereas another action item (MOCR to be initiated to add local display for relief flow alarms or hi/low relief tanks levels on HMI screens at Crane) was dropped

4.9 Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-4. Service Interruptions per Month

	Ja n	Fe b	Ma r	Ap r	Ma y	Ju n	Ju l	Au g	Se p	Oc t	No v	De c	Total *
No./Mont h	1	5	2	1	0	0	0	0	0	0	0	0	9

* From the Daily Ops Report ending Dec 31.

4.10 Incorrect Operations and Near miss Reports

Incorrect operations were documented in internal incident investigation reports of minor incidents, but the 2 DOT-reportable incidents in 2011 were not caused by incorrect operations.

There were 4 ROW near misses reported in 2011 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 Kiefner 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 2011 there was a single One-Call violation, the same as 2010.

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

The number of TPD near misses for 2011 was four. These were taken from the 2011 TPD Annual Assessment and Incident 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				1	3
Tier 2					1								1
Tier 3													0
Total	0	0	0	1	1	0	0	1	0	0	0	1	4

Unauthorized ROW Encroachments (Item 52)

There were no unauthorized encroachments in 2011. There were four (4) near misses documented in the 2011 TPD Annual Assessment, one of which was located in a Tier 2 Risk Zone. One of these near misses was neither an authorized nor unauthorized encroachment, and was not documented in the Encroachment report. (See 3.1 in the main report for discussion.)

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 2011 TPD Annual Assessment. Of the four near misses on the pipeline in 2011 one was classified as a One-Call violation on the Incident Investigation Reports and in the TPD Annual Assessment.

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

The 2011 TPD Annual Assessment shows a 52-percent drop in Non-Company activity level from unique aerial patrol observations. This is primarily due to a decrease in housing development, and miscellaneous TP activity.

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

Total possible mileage includes the 694-mile main line plus the 29-mile lateral from Crane to Odessa, and the laterals from El Paso Terminal to Diamond Junction. This year the 3.5-mile double lateral from East Houston to MP 6 was added to the patrol mileage. 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 the Edwards Aquifer recharge zone (Milepost 170.5 to Milepost 173.5). The cumulative miles of patrols for these three 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	22	25	14	8	11	14	11	14	11	14	14	25	185
Galena Park to Crane	13,785	11,660	14,890	15,107	14,797	15,736	16,120	15,698	15,494	15,807	14,174	11,615	174,883
Crane to El Paso	1,320	1,056	1,056	969	1,175	1,056	1,056	1,320	1,056	1,056	1,320	1,056	13,496
Total	**15,127**	**12,741**	**15,960**	**16,084**	**15,983**	**16,806**	**17,187**	**17,032**	**16,561**	**16,877**	**15,508**	**12,696**	**188,564**

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.

There were episodes of bad weather prohibiting aerial patrols, where ground patrols were organized to complete (or in an attempt to complete) the required right-of-way patrols.

In addition there were examples of poor record keeping practices that should be corrected in future years. These practices affect the mileage tally reported in table B-6 above which is a performance metric of the Annual ORA. Occasionally these poor record keeping practices might affect the ability to determine whether the LMP patrol requirements are being met, although it could not be documented for the records reported for 2011.

- In many of the reports the additional 3.5 miles of inspection for the lateral to East Houston were not included in the reported ROW miles inspected. The reporting of these miles needs to be consistent. In counting the miles, it was assumed these 3.5 miles were inspected as long as the pipeline was inspected at MP 6 were the double pipeline ties into the 9 mile extension from Galena Park to the original 1950 pipeline.
- There was one instance on December 26, 2011 where an aerial patrol and ground patrol were documented. Both were counted, but the double inspection seams peculiar. From discussions this can sometimes happen when the weather is poor, but documentation of deliberate double inspections would help alleviate any suspicion of poor record keeping.
- On October 8-9, 2011 partial patrols were documented, but the mileage documented included the entire 532 miles normally inspection from Galena Park to the Pecos River. Because the reduced mileage was not documented the entire 532 miles was included in the tally.
- In several instances where a patrol was performed between Crane and El Paso, the patrol record between Galena Park and the Pecos River double counted the miles between MP 457 and MP 528. A consistent accounting method for this interval is needed on days when the Crane to El Paso patrol is performed. For the tally above it was assumed this was a double count and the Galena Park to MP 528 interval was reduced to 461 (457 + 4) miles.

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

The number of pipeline markers repaired or replaced is 298 and comes from the TPD Annual Assessment. This is a 2-percent increase from 2010. The 2010 Mitigation Plan Scorecard lists the monthly sign replacements as follows.

Table B-7. Markers Repaired or Replaced

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	35	3	5	7	62	3	1	158	21	1	2	0	298

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

EVENT	2005	2006	2007	2008	2009	2010	2011
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11
School Program:							
School Program - Houston	2	2	3	4		6	5
School Program - Austin	3	2	7	3	4	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	2	
TOTAL	**28**	**18**	**25**	**21**	**17**	**22**	**20**

NOTE: Public meetings were tallied for the years 2005-2010 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, home shows, 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 2011 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	416	426	675	505	460	505	491	516	438	515	486	324	5757
II	278	314	520	431	371	408	375	405	373	374	342	224	4415
III	59	66	108	91	79	87	78	85	75	77	69	44	918
Total	**753**	**806**	**1303**	**1027**	**910**	**1000**	**944**	**1006**	**886**	**966**	**897**	**592**	**11090**

Public Awareness Summary Annual Report (Item 60)

- The Public Awareness Summary Report for 2011 was received covering information related to public education and damage prevention ads

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	Total
Safety/Environment	89	124	126	95	97	85	117	93	92	106	77	112	1213
– Call Before You Dig	53	34	57	49	29	44	45	36	71	41	32	112	603
– Pipeline Safety	76	109	99	95	76	63	76	81	104	95	67	106	1047
– System Integrity Plan	61	97	77	77	63	63	67	71	70	84	71	69	870
– Longhorn Info.	158	328	403	412	411	357	290	424	365	374	385	274	4181
– Pipeline Emergencies	21	43	32	23	20	27	25	81	23	28	24	70	417
– Call Before You Dig Video	0	0	3	0	0	0	0	0	2	1	0	3	9
Home Page – 811 Logo	2	3	1	1	1	0	1	0	0	2	0	1	12
Total	**460**	**738**	**798**	**752**	**697**	**639**	**621**	**786**	**727**	**731**	**656**	**747**	**8352**

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	6	2	3	9	9	11	4	12	10	7	0	3	76
Unauthorized													0
Total	**6**	**2**	**3**	**9**	**9**	**11**	**4**	**12**	**10**	**7**	**0**	**3**	**76**

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

Two physical hits to the pipeline requiring coating repair that were reported in 2011, while no physical hits were recorded in the previous 5 years from 2006-2010.

Annual TPD Assessment Report (Item 71)

The Longhorn System 2011 Annual Third Party Damage Prevention Program Assessment (TPD Annual Assessment) was received October 11, 2011. 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 11,090 One-Call notifications were made.

Table B-12. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	237	58	753
Feb	302	41	806
Mar	405	114	1303
Apr	349	102	1027
May	296	113	910
Jun	306	108	1000
Jul	328	75	944
Aug	275	97	1006
Sep	231	112	886
Oct	208	126	966
Nov	221	107	897
Dec	159	69	592
Totals	3317	1122	11090

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, a minor injury which did not require hospitalization, or non-jurisdictional incidents unrelated to the pipeline. There was one incident that required a report to DOT/PHMSA, a seal failure on block valve SE4 at Warda Station caused a spill of 99 gallons.

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

None received in 2011.

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

PHMSA Advisories

DEPARTMENT OF TRANSPORTATION ADB-11-05 September 1, 2011
Pipeline and Hazardous Materials Safety Administration
[Docket No. PHMSA–2011–0183]
Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.
ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to remind owners and operators of gas and hazardous liquid pipelines of the potential for damage to pipeline facilities caused by the passage of hurricanes.
DEPARTMENT OF TRANSPORTATION ADB-11-04 July 11, 2011
Pipeline and Hazardous Materials Safety Administration
[Docket No. PHMSA–2011–0177]
Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.
ACTION: Notice; Issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused
by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in case of flooding.

DEPARTMENT OF TRANSPORTATION ADB-11-07 July 12, 2011
Pipeline and Hazardous Materials Safety Administration 49 CFR Part 190
[Docket No. PHMSA–2011–0161]
Pipeline Safety: Enforcement Proceedings Involving an Informal Hearing
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
ACTION: General policy statement; informal hearing process.

SUMMARY: PHMSA is issuing this document to notify operators of natural gas and hazardous liquid pipeline facilities of the creation of a dedicated ‘‘Presiding Official’’ for informal pipeline enforcement hearings and the process operators can expect when requesting an informal hearing.
Hearings in pipeline safety enforcement cases are conducted by a hearing officer in accordance with certain procedures designed to ensure a fair and impartial decision on the merits. This document explains those procedures and includes a description of the dedicated hearing officer’s roles and responsibilities, the process for requesting a hearing, and the manner in which a case will proceed once a hearing has been requested.

DEPARTMENT OF TRANSPORTATION ADB-11-01 January 10, 2011
Pipeline and Hazardous Materials Safety Administration
[Docket No. PHMSA–2010–0381]
Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
ACTION: Notice; issuance of Advisory Bulletin.

SUMMARY: PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities of their responsibilities, under Federal integrity management (IM) regulations, to perform detailed threat and risk analyses that integrate accurate data and information from their entire pipeline system, especially when calculating Maximum Allowable Operating Pressure (MAOP) or Maximum Operating Pressure (MOP), and to utilize these risk analyses in the identification of appropriate assessment methods, and preventive and mitigative measures.

4.15 DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2011.

4.16 Literature Reviewed

See references.