Magellan Pipeline Company

Final Report No. 11-128

Final Report

2010 Operational Reliability Assessment of the Longhorn Pipeline System

Harvey Haines, Carolyn Kolovich, and Dennis Johnston

December 30, 2011

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on

2010 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

December 30, 2011

by

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TERMS, DEFINITIONS AND ACRONYMS

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

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

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

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

AC – Alternating Current.

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

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

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

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

d – defect depth.

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

***DOC* –** Depth of cover.

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

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

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

EPA – Environmental Protection Agency.

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

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

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

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

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

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

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

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

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

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

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

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

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

L – defect length.

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

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

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

MASP – Maximum Allowable Surge Pressure

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

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

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

MOCR – Management of Change Recommendation

MOP – Maximum Operating Pressure

MP – Mile Post.

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

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

OD – Outside nominal diameter of line pipe.

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

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

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

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

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

ORAPM – The ORA Process Manual.

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

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

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

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

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

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

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

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

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

ROW – Right-of-way.

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

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

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

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

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

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

TFI – Transverse Field Inspection – an MFL Inspection tool with the field oriented in the circumferential direction. The tool differs from conventional MFL 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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2010 Operational Reliability Assessment of the Longhorn Pipeline System

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1. INTRODUCTION

Objective

This report presents the annual assessment of the operational reliability of the Longhorn Pipeline System for the 2010 operating year. Kiefner and Associates, Inc. (KAI) has carried out the operational reliability assessment (ORA) which is intended to provide Magellan with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP), incorporate the results of all elements of the LPSIP as attributes and data to consider in the overall assessment of the mechanical condition of the Longhorn assets, and provide recommendations to preserve the long term integrity or mitigate areas of potential concern before they result in a breach of the pipeline system.

Background

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

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

The LMP stipulates specific and general requirements of the ORA. Those requirements were extracted from the LMP and used to develop the Operational Reliability Assessment Process Manual (ORAPM). The ORA is carried out according to the ORAPM, revised as of April, 2011. Additional guidance for the ORA is provided by the "Mock ORA for Longhorn Pipeline" that was performed by KAI prior to commissioning of the pipeline. Among other things, the ORAPM requires the ORA contractor to provide periodic reports to Magellan and DOT/PHMSA.

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

ORA Interaction with the LPSIP

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

The twelve elements of the LPSIP are:

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

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

Longhorn Pipeline System Description

The Longhorn Pipeline is comprised of 18 and 20-inch diameter pipe, which extends 694 miles from Galena Park, Texas to a terminal located 3 miles east of El Paso, Texas, plus an 8-inch lateral which extends 29 miles from Crane to Odessa, Texas, and 4 laterals which extend 8.5 miles from El Paso Terminal to Diamond Junction. 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 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.

The original 1950 Exxon pipeline is described in the EA as the Existing Pipeline to differentiate it from the New Pipeline extensions installed in 1998. The currently operating pipeline does not include the J-1 Valve because the 9 mile extension from Galena Park to MP 9 was connected with the Existing Pipeline approximately 2 miles downstream of the J-1 Valve. In addition, there is also no pig launcher at this junction at MP 9, so effectively when commitments for the Existing Pipeline (Valve J-1 to Crane) are performed, they are required on the active Existing Pipeline (MP 9 to Crane) and performed from Galena Park (MP 0) to Crane (MP 457.5). And since the loop to East Houston Station was added in 2010, these commitments for the Existing Pipeline will apply from East Houston Station to Crane.

Time Scope

This report presents the annual assessment for 2010 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 2010 annual ORA report of the Longhorn system assets addresses the following subjects:

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

The analyses of operational pressure cycles to date show that the intensity of pressure cycles is relatively nonaggressive in relation to benchmarks established on the basis of typical liquid petroleum products and crude oil pipelines. If this continues to be the mode of operation, integrity reassessment from the standpoint of electric-resistance weld (ERW) seam anomalies will not be necessary until the year 2048. 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. The UT data was used in conjunction with the previous MFL metal loss tools to assess corrosion growth on the pipeline. In addition, excavations were completed in 2010 for the ILI UT tool runs from Galena Park to Satsuma and Satsuma to Warda.

The condition of any laminations and blisters using UT ILI data was performed on the Galena Park to Satsuma and Satsuma to Warda pipeline segments. From 2,777 laminations identified in these two segments, 46 excavations were selected and no blistering of the laminations was identified.

From the standpoint of earth movement, the primary integrity concerns are soil erosion and scouring from floods and the ground movement from aseismic faults at specific points along the pipeline. Scour surveys on the Colorado River and its tributary Pin Oak Creek show little to no evidence of soil erosion or scouring. The remaining river crossings were inspected in 2010, as part of their 5-year reinspection requirement. As of 2010, 6 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. In our opinion, the damage prevention program is a major contributing reason why no hits occurred on the pipeline in 2010. Two near-misses occurred and were caused by third parties erecting fences who did not use the One-Call system. Both were found by aerial patrols, showing their value and demonstrating the need to perform ground patrols when the required aerial patrol frequency cannot be met.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. In accordance with the ORAPM, Longhorn performed investigative digs each year for the three years from 2005-2007 in areas potentially susceptible to SCC. No SCC was found. Magellan continues to carry out 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 2010, one can conclude that pump station and terminal facilities had no adverse impact on public safety. Only one small reportable release of product occurred which was contained onsite so there was no risk to public safety.

The technical assessment of the LPSIP indicates that Magellan is achieving the goal of the LPSIP, namely, to prevent incidents that would threaten human health or safety or cause environmental harm. In terms of activity measures, Magellan exceeded the goals of aerial surveillance and ground patrol frequency. In addition, public-awareness meetings were held, an equipment rental/farm store public education program was conducted, and right-of-way markers and signs were repaired or replaced where necessary. From the standpoint of deterioration measures, the number of anomalies found per mile requiring excavation is decreasing with the second and third ILI tool inspection. In terms of failure measures, there was one DOT-reportable incident and there were no known third-party hits.

3. RECOMMENDATIONS

3.1 Technical Assessment of LPSIP Effectiveness

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

Longhorn Corrosion Management Plan

The corrosion management plan has been effective at preventing corrosion degradation in 2010. Internal corrosion coupon results show little to no corrosion. Although some inspections of the CP system were missed because of poor performance by the employee responsible, no stations fell below criterion when inspections were resumed.

In-Line-Inspection and Rehabilitation Program

Magellan completed the inspection of the existing pipeline (Valve J-1 to Crane) in 2010 completing the requirement of LMC 12. Other than the delay of completing this commitment by January 26, 2010, Magellan continues to meet its ILI commitments and the program has been effective at fulfilling the integrity requirements in the LMP.

Damage Prevention Program

The absence of reportable incidents involving mainline pipe and the absence of third party contact with the pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended.

Encroachment Procedures

There were 106 encroachments recorded in 2010 of which 1 was unauthorized. The program's encroachment agreements have been effective at keeping authorized encroachments from damaging the pipeline. This is demonstrated because none of the authorized encroachments resulted in contact with the pipeline, while the unauthorized encroachment did result in a near-miss. In addition, the absence of third party damage also support that the program has been effective.

Incident Investigation Program

Magellan is performing incident investigations on all DOT reportable incidents and on many more non-reportable incidents. Incident investigations were reviewed on all near-misses. KAI finds these incident investigations sufficient. This program is effective in helping Magellan determine the root cause of incidents on the pipeline in an effort to prevent future incidents.

Depth of Cover Program

A Depth of Cover (DOC) survey was last performed in 2007. The November 2010 aerial patrol for earth movement found 3 areas of exposed pipe that need to be integrated into the Depth of Cover Program in 2011. Section 5.4 and Section 7 cover this in more detail. The program has been effective in that no damage has resulted to the pipe because of exposed or shallowly buried pipe.

Fatigue Analysis and Monitoring Program

The 2010 fatigue analysis performed by KAI incorporated results from the 2007-2008 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. The analysis for this program is covered under Section 5.1 of this report.

3.2 Recommended Intervention Measures and Timing

Pressure-Cycle-Induced Fatigue

For the threat of pressure-cycle-induced fatigue, a reassessment in the year 2048 was calculated based on the pressure cycles for 2008 through 2010 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 and the remaining six sections should be complete in 2011.

Laminations and Hydrogen Blisters

No instances of blistered laminations have been discovered to date from the excavations of anomalies on the Galena Park to Satsuma or the Satsuma to Warda pipeline segments. Magellan should monitor the lamination locations with ILI tools to verify that no blisters are forming. The monitoring frequency recommended would coincide with the metal loss reassessment schedule.

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

Third-Party Damage

For the threat of TPD, Magellan should continue both prevention and inspection activities. Prevention activities include ROW surveillance and public-awareness activities that continued to be successful in 2010. 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 are occurring more frequently because they also fulfill other Longhorn Mitigation Commitments. For specific inspection dates (to fulfill the requirement for each of the six intervals spanning the Existing Pipeline from Galena Park to Crane) see Table 9 in Section 7 on Integration of Intervention Requirements.

Stress-Corrosion Cracking

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

Threats to Facilities Other than Line Pipe

Magellan should continue to carry out inspections and maintenance of facilities with the same diligence and frequency as performed in 2010.

3.3 Implementation of New Mechanical Integrity Technologies

No new technologies were implemented in 2010.

3.4 ORA Process Improvements

The ORAPM provides a method for determining corrosion rates by comparing two consecutive ILI runs. This method has not been effective for determining a corrosion rate because two different technologies were used to assess the metal loss. The average difference in external metal loss readings between the UT and MFL tool data divided by the difference in years was generally less than the default corrosion rate of 6 mils per year (from ASME B31.8S), however it is difficult to discern tool noise from actual corrosion growth. As a result KAI has used a corrosion rate of 6 mils per year. In an attempt to improve this process, Magellan has contracted with Quest to perform an independent study the three ILI runs since startup with the goal of determining an average corrosion growth rate for each segment. Results will be available in 2011.

4. NEW DATA USED IN THIS ANALYSIS

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

5. RESULTS AND DISCUSSION OF DATA ANALYSIS

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

5.1 Pressure-Cycle-Induced Fatigue Cracking

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

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

The failure pressure of each defect is controlled not only by its size, but by the diameter and wall thickness of the pipe, the strength of the pipe, and the toughness of the pipe. Toughness is the ability of the material containing a given-size crack to resist tearing at a particular value of applied tensile stress. Toughness in line-pipe materials has been found to correspond reasonably well to the value of "upper-shelf" energy as determined by means of standard Charpy V-notch impact tests. As noted in Reference[1,] the Charpy V-notch energy levels for samples of the 1950 material ranged from 15 to 26 ft-lb. Prior to completing the TFI tool run, the ORAPM specified a process that used the previous hydrostatic test pressure levels to determine a starting defect size. In this case, toughness is a factor for establishing starting defect sizes and it is more conservative to use a higher value of toughness as it allows for a larger defect to remain after the hydrotest. Note that toughness is not a factor in establishing either starting defect size using the ILI detection threshold or the N10 notch. However, toughness is needed to calculate the size of the defect that will cause failure at the operating pressure. In these cases, a lower toughness value generally leads to more conservative calculated fatigue lives. However, for the specific flaw sizes used in our analysis, the fatigue life does not change whether 15 ft lbs or 25 ft lbs is assumed. This is due in part to the relatively short length of the starting defects. With a longer defect, it would be expected that using a value of 15 ft lbs instead of 25 ft lbs would decrease the fatigue life. We have used a value of 15 ft lbs in our calculations.

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 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 92.1 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 45.5 years based on the current operating pressures. An assessment would be required in 2048 as this pipe was inspected in 2007. Again as stated above, the predicted time to failure using Paris Law is based on the crack growth rate given in the Fitness-For-Service API Standard 579-1/ASME FFS-1 for weld-metal material.

A fatigue life was also calculated for the new 1998 pipe material at Galena Park Station, and Crane Station based on the maximum flaw size that could exist as stated by the manufacturer. This flaw is described above as an API 5L N10 notch, a 10-percent, 2-inch-long flaw, and was used to calculate the fatigue life at these locations. Table 1 summarizes the locations evaluated.

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

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

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

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

	Time to Failure for a Defect That May Be Present, Years	Recommended Reassessment Interval (Includes Safety Factor of 2.2)	Year of ILI Tool Run/Installation	Recommended Year of Next Assessment
Case 1	> 500	> 225	2000	> 2225
Case 2	428.6	193.1	2007	2200.1
Case 3	> 500	> 225	2007	> 2232
Case 4	110.9	50.0	2007	2057.0
Case 5	344.0	155.0	2007	2162.0
Case 6	131.9	59.4	2007	2066.4
Case 7	***92.1***	***41.5***	***2007***	***2048.5***
Case 8	> 500	> 225	2008	> 2233
Case 9	> 500	> 225	1998	> 2223

5.2 Corrosion

Corrosion Control

Several CP system inspections were not performed within their required intervals, causing Magellan to terminate the employee responsible. Inspections completed outside the required time interval showed no problems with the CP system although some rectifier outputs were increased. We do not expect there will be any significant integrity concerns as a result of this problem and the ORA requires corrosion inspections using ILI between September 2014 and July 2015 which will allow Magellan to correct any degradation which may have occurred.

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

ILI results are commonly used by pipeline operators as a means for identifying and evaluating corrosion-caused metal loss and planning remediation. This typically involves running an ILI tool to identify, size, and excavate corrosion 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.

Corrosion Growth Analysis

The metal loss data from the UT tool were correlated to the previous MFL metal loss data to determine if corrosion growth rates could be calculated. The UT metal loss did not call many of the internal metal loss calls from the previous MFL tool runs. The previous MFL internal metal loss calls are interpreted to be due to surface roughness or magnetic artifacts. Had internal metal loss actually been present on the pipeline, the UT tool would have called them due to a reduction in the pipe thickness and an increase in the stand-off distance between the UT transducer and the inside surface of the pipe. Internal corrosion is not a concern for the pipe between Galena Park and Crane.

The average difference in external metal loss readings between the UT and MFL tool data divided by the difference in years was generally less than the default corrosion rate of 6 mils per year (from ASME B 31.8S). Based on these results and the scatter in the correlation, 6 mils per year was used as the corrosion rate for external metal loss anomalies that have not been addressed.

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. Twenty-two excavations were performed on the Galena Park to Satsuma segment and 24 excavations were performed on the Satsuma to Warda segment. No instances of hydrogen blistering were found on any of these digs.

The probability of adversely affecting the pipe laminations is low due to the refined products transported by the Longhorn pipeline. The only 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.

5.4 Earth Movement (Fault and Stream Crossings)

Fault Crossings

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

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

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

Monitoring stations across the faults were installed in March 2004 in accordance with section 6.2 of the ORAPM. Baseline readings were taken in late May and early June 2004. Eight subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the displacements over time is shown in Figure 1 below. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. With 6½ 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 0.05 inch (1.3 mm) over 6½ years for the Akron fault and -0.06 inch (-1.5 mm) over 6½ years for the Hockley fault.

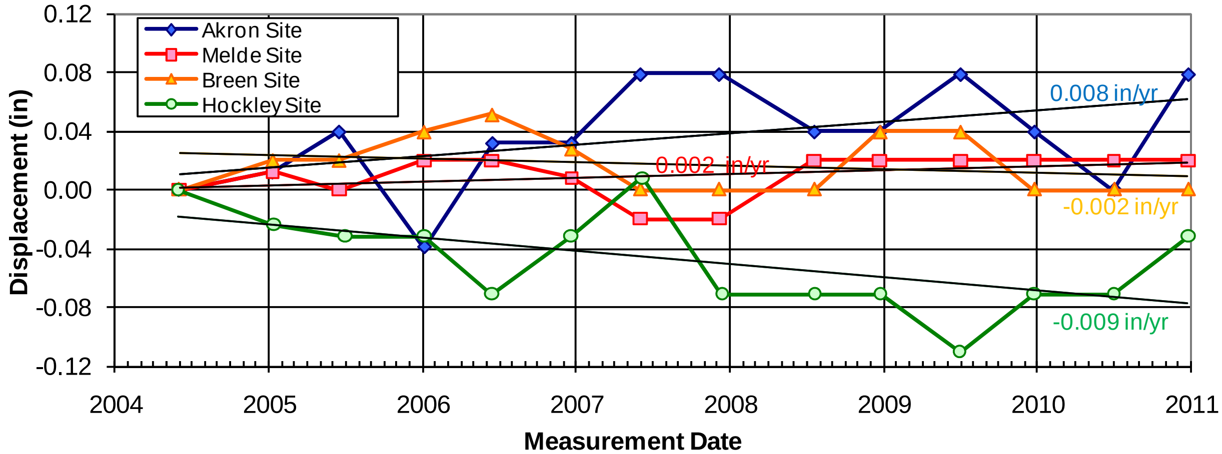

Figure 1. Fault Displacement Over 6½ Year Period

For this year's analysis with 6½ years of data, we used the calculated movement from the best fit trend lines and compared these estimates of fault growth to the KAI stress analysis described in the 2005 ORA Annual Report. Table 4 shows the amount of movement at each fault that can occur before it exceeds the stress levels allowed by ASME B31.4. The differences in allowable fault displacements are caused in large part by differences in the angle of the fault movement.

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

	Displacement (in)	Years to Reach Displacement
Akron	4.17	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 4 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 6½ 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.

Even though the shortest time to failure for the other three faults is over 500 years, according to the U.S. Geological Survey, September 2005[4] there are documented cases of fault movement reinitiating, so monitoring every five years is 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 inspected once in 2010 on June 25. Results show some small changes in the toes on the banks of the Colorado River and Pin Oak Creek, but do not indicate any significant scouring. The other crossings were last inspected as part of the Aerial Inspection below.

Every 5 year Aerial Inspection

An aerial survey of the pipeline is required every five years to examine areas of concern such as stream crossings and areas of potential land movement. The survey was completed in November 2010 and no areas of immediate concern were identified, although the survey identified 3 areas that appeared to have changed since the last survey and added 13 locations that were not previously documented. The report concluded that areas showing exposed, or potentially exposed, pipeline sections should have more detailed inspections conducted.

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 2010 TPD Annual Assessment we conclude:

- There were 2 near misses reported.
- Of the 2 near misses, 1 was documented as an unauthorized ROW encroachment.
- No documented physical hits to the pipeline occurred in 2010, the same as in 2006 through 2009.
- There were 2 One-Call violations reported in 2010. This is fewer than any previous year except for 2006 where 0 One-Call violations occurred.
- The TPD Annual Assessment shows a 7-percent decline of unique aerial patrol observations, with a 12-percent drop in third-party activity or non-company aerial-patrol-observations.
- Total One-Call tickets as tabulated in the 2010 TPD Annual Assessment are 21-percent lower than the total from 2009.

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 2010 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. Because this is the third set of ILI tools run in the pipeline, mechanical damage found by ILI should be a rare occurrence. 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 data 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 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 it 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.

One-Call Violation Analysis

Out of 10,425 One-Calls in 2010, it appears that 12.3-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 6,034 (58-percent) of the One-Call tickets. Travis County accounted for 1,413 (14-percent) of the One-Call tickets. Thus, fully 72-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 290 tickets (2.8-percent). Given that there were no known hits on the pipeline, one could reasonably conclude the One-Call system and Magellan's surveillance plans are working well.

Figure 2 below shows a flow chart analysis of the One-Calls. Out of 10,425 One-Calls, none resulted in a near miss to the pipeline. In addition, there were two cases where a third-party landowner did not, but should have used One-Call to notify Magellan of activity in the ROW resulting in One-Call violations. Exemptions from using One-Call are allowed if the excavation is shallower than 16 inches and no mechanized equipment is used. Both violations were caused by a landowner installing a fence across the ROW.

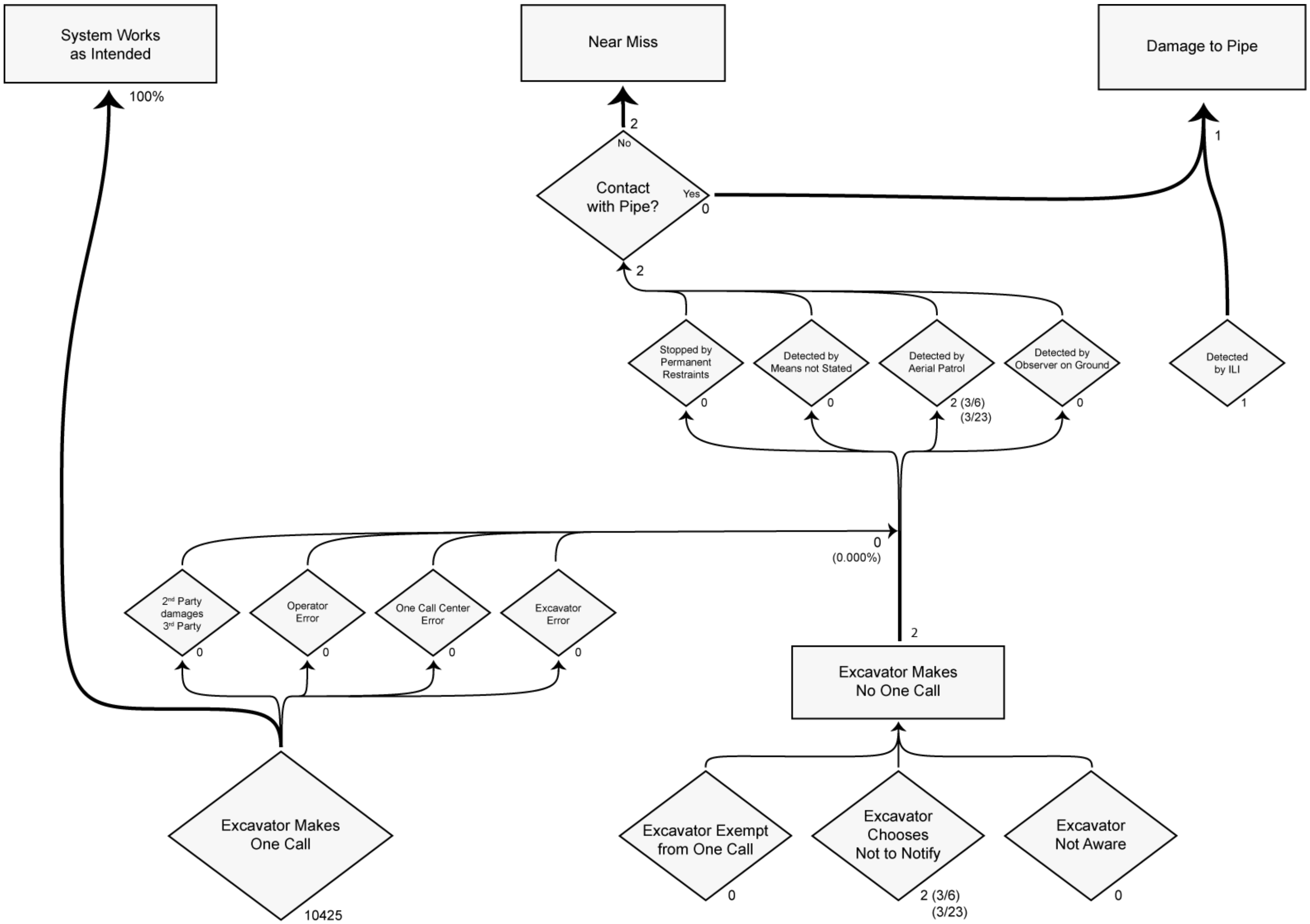

Figure 2. Flow Chart of 2010 One-Calls to the Longhorn System

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 2010, show that Magellan exceeded these requirements in terms of the number of aerial and ground patrols. Magellan implemented a process improvement after the 2008 ORA Annual Report was issued to perform ground patrols to supplement aerial patrols when poor weather prevents them. It appears that this process improvement has prevented instances where aerial patrols were unable to inspect Tier II & III areas within 72-hours of the previous patrol.

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 were only two One-Call violations during 2010. Therefore, there is no requirement to conduct an additional ILI inspection with a geometry tool at this time even though one had been run in conjunction with the LMC 12 and 12A requirements. LMC 12A, requires that a “smart” geometry tool (a tool capable of detecting third party damage, such as TFI, MFL, or geometry tool) should be run no more than every three years after startup. Magellan ran a geometry tool in conjunction with LMC 12 (the requirement to run a UT within five years of startup).

No additional direct examinations are recommended at this time. Magellan should continue to carry out the same level of aerial surveillance and the same level of One-Call response that has occurred in 2010. Magellan should continue to carry out One-Call response in 2011 as specified in the LMP.

5.6 Stress-Corrosion Cracking

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

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

5.7 Facilities Other than Line Pipe

From the standpoint of facilities data acquired in 2010, 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

Ten 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
- Satsuma Pump Station
- Eckert Pump Station
- Ft. McKavett Pump Station
- Kimble County Pump Station
- Crane Pump Station
- Cottonwood Pump Station
- El Paso Terminal

Three facilities incident data reports were received which concerned facilities in 2010, none of which were DOT reportable incidents. All of these incidents involved a spill of product (2 to 10 gallons) which were caused by a pump seal at El Paso, a prover valve stem at Crane, and a filter vessel flange at El Paso.

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 2010 is evaluated below.

Activity Measures

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

Number of miles of pipelines inspected by aerial survey and by ground survey (by pipeline segment) in a 12-month period. Compare to the previous 12-month periods. This measure will be used to compare Longhorn Pipeline surveillance performance to previous year's surveillance of the same system. The goal would be 100-percent of the commitment. Magellan met this commitment in 2010.

Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric will be compared to previous Magellan performance. This metric will be used to measure consistent effort by Magellan to protect the ROW and to prevent TPD. There will not be a "passing grade" established, because proper placement and maintenance of signs may lead to fewer signs replaced or repaired in future years, and this decline will not indicate any failing on the part of Magellan. On the other hand, tracking the replacement or repair of signs by pipeline segment may indicate third party vandalism or carelessness in certain segments of the system. This could be used as a leading indicator that additional public education might be needed in that region of the pipeline route.

Number of outreach or training meetings (listed with locations and dates) to educate and train the public and third parties about pipeline safety. This metric will be used to gauge consistent effort by Magellan to educate the public regarding pipeline safety, with the goal of preventing TPD to the pipeline. There will not be a "passing grade" established, although the ORA contractor will review and compare the results of this metric with the results of the previous metric (sign placement, repair and replacement) to see if the effort at public education is being emphasized in the same geographic region where sign maintenance indicates problems. See Appendix B Item 58 for details.

Number of calls ([sorted by Tier I, Tier II or Tier III) through the One-Call system to mark or flag the Longhorn Pipeline. This will help measure the effectiveness in the One-Call system in preventing TPD. The measure will be compared to previous years of Magellan records. Since this is a metric that is not subject to control by Magellan, a "passing grade" will not be established. However, this metric will also be compared to a failure metric described below (report of encroachments into the ROW that were not preceded by a One-Call contact). This comparison will allow overall measurement of how efficiently the One-Call process is being used.

Table 5. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010
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
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	545*	475*	291
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17	36
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	5277
	Tier II	6,881	7,874	7,852	7,059	5,840	4265
	Tier III	1,498	1,617	1,653	1,459	1,217	833

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

Deterioration Measures

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

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

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

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

Table 6. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	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
	Tier II	NA	0.0208	NA	NA	0	0
	Tier III	0.192	NA	0.003	NA	0	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA	NA
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017	0.14

Failure Measures

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

Table 7. LPSIP Failure Measures

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

* 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.

Tables 8a and 8b 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 2009 ORA. Earth movement, the fifth component for threat integration, is not included in Table 8a or 8b because it is currently addressed using surface surveys rather than ILI technology. Because of slow throughput on the pipeline Magellan was unable to meet LMC 12 for two segments of the pipeline, LMC 12 is the requirement to run a UT tool within five years of startup (January 26, 2010) for addressing the threat of hydrogen blisters. Eckert to Ft. McKavett was five months late and Ft. McKavett to Crane was seven months late. Magellan continues to meet its commitments for Corrosion, Third Party Damage, and Pressure-Cycle Induced Fatigue.

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. As of this writing of results from the "Areas of Concern" report are being integrated with the 2007 Depth of Cover investigation to determine if these are new areas of exposure that should be integrated into the Third Party Damage prevention program. Results should be reported in the 2011 ORA.

Table 8a. Existing ILI Runs and Planned Future Inspections

			Threats Addressed			
	Tool	Date of Tool Run	Corrosion	Pressure-Cycle Induced Fatigue	Laminations and Hydrogen Blisters	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 8b. 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
	Next Required Assessment		***4-Nov-11***	*Not susceptible*	*Not susceptible*	***4-Nov-11***
El Paso to Diamond Jct. (4 Lines)	HRMFL/Deformation	7-Mar-07	X			X
	Next Required Assessment		***7-Mar-12***	*Not susceptible*	*Not susceptible*	***7-Mar-12***

Integration of DOT HCA and TRRC Inspection Requirements

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

The HCA rule states that an operator must establish five-year intervals, not to exceed 68 months, for continually assessing the pipeline's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the HCA to determine the priority for assessing the pipe. At this time, corrosion has proven to be the higher priority risk of the five threats to the pipeline integrity. Because of the requirements of the LMP and the multiple capabilities of each of the required tools, the HCA line pipe between Galena Park and Crane is being inspected in intervals 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 to be completed prior to startup (prior to June 10, 2002). Replacement of the other four segments is to be completed no later than seven years after startup (must be completed by January 26, 2012). Construction of these replacements was ongoing at the time of this report.

Other Pipe Replacements

None noted in 2010.

8. RECOMMENDED IMPROVEMENTS TO THE ORA PROCESS

Table 9. Summary of 2009 Recommendations

Topic	Recommendation	ORA Ref Page
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	16-18
Exposed pipe	The 2010 *Aerial Inspection and Photo-documentation of "Areas of Concern"* report should be integrated with the Depth of Cover program in 2011 to determine if these are new areas of exposure that should be integrated into the Third Party Damage prevention program.	16 & 27
Damage Prevention	Because fence contractors were responsible for two of the near misses to the pipeline in 2010, Magellan should implement an appropriate measure to increase fence contractors' awareness of One-Call and the potential damages that can result from TPD to the pipeline.	18-19
Mechanical Damage discovered by ILI or anomaly investigation	Mechanical damage discovered by ILI anomaly investigations should have incident investigation performed to determine if possible the time and cause of the damage for all future mechanical damage anomalies. This particular incident will be reviewed in the 2012 annual SIP review.	18

REFERENCES

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

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

4.3 ILI Inspection and Anomaly Investigation Reports

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

Data was received from the following evaluations completed in 2010.

Table B-1a. Excavations Completed in 2010

Line Segment	20" Galena Park to Satsuma	18" Satsuma to Warda
ILI Date	9/22/2009	11/24/2009
Maintenance Report	yes	yes
Tier 1	2	24
Tier 2	17	0
Tier3	3	0
Total Digs	22	24
HCA	20	0
Non-HCA	2	24

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

Line Segment	20" Galena Park to Satsuma	18" Satsuma to Warda
Ext ML & Laminations	1	0
Weld Inhomogeneity, possible sliver	5	0
Lamination & Dent	1	0
Lamination associated with BRC metal loss	0	1
Lamination	6	7
Surface Irregularity, possible sliver	2	2
Geometrical anomaly with metal loss	0	1
Weld irregularity	0	1
Possible Sliver	4	0
Dent adjacent to girth weld	0	1
Dent	1	2
Metal loss possible weld defect	0	1
Metal loss possible surface breaking laminations	0	1
Ext ML	2	7

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 2010 excavation reports, no blisters have been found on either the Galena Park to Satsuma or the Satsuma to Warda segments.

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 2010.

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 corrosion growth rates for anomalies detected by each tool. The average change in the predicted depths predicted by the UT and MFL tools divided by the time between runs was less than 6 mils per year. Six mils per year is considered to be a conservative estimated external corrosion growth rate for the majority of soil resistivity's from ASME B 31.8S.

Internal Corrosion Coupon Results (Item 37)

Three internal corrosion coupon reports were reviewed for the 2010 annual report. Three lines were sampled with coupons placed in the 8-inch Odessa lateral at Crane, the Plains 8-inch lateral at El Paso, and the 18-inch main line at El Paso. Little to no corrosion was observed with measured corrosion rates all much less than 1 mil per year.

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

Inserted	Removed	Exposure (days)	Rate (MPY)	Portion of Test Surface Rusted	Under Holder Attack	Comments
1/4/2010	5/3/2010	119	0.00	None	none	
5/3/2010	9/1/2010	121	0.00	None	none	
9/1/2010	12/30/2010	120	0.00	< 0.1%	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
12/31/2009	5/1/2010	121	0.00	None	none	
5/1/2010	9/1/2010	123	0.00	<0.1%	none	
9/1/2010	1/3/2011	124	0.00	<0.1%	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
12/31/2009	5/1/2010	121	0.00	None	none	
5/1/2010	9/1/2010	123	0.00	None	none	
9/1/2010	1/3/2011	124	0.00	None	none	

Line Pipe Anomalies/Repairs (Item 43)

See section 4.3 above.

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

See section 4.3 above.

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

See section 4.3 above.

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

See section 4.3 above.

4.6 Fault Movement Surveys and Natural Disaster Reports

Pipeline Maintenance Reports at fault crossings (Item 30)

No maintenance reports were received covering the fault crossings in 2010.

Periodic fault benchmark elevation data (Item 31)

Semi-Annual Fault Displacement Monitoring Reports dated July 23, 2010 and January 17, 2011 were received which covers semi-annual fault measurements at the four fault monitoring sites since inception in mid 2004 through December 2010.

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 monitored June 25, 2010.

Flood Monitoring (no item number)

Flood monitoring spreadsheets were received for Colorado River, Pin Oak Creek, and the Pedernales River. The Pedernales River is the only one of these three that entered flood stage and it did so on September 8, 2010.

Other Earth Movement Monitoring (no item number)

A December 2010 report covering Aerial Inspection and Photo-documentation of potential earth movement that could be caused by landslides or stream scouring was received.

4.7 Maintenance and Inspection Reports

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

No new surveys were made in 2010.

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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep*	Oct	Nov	Dec	Total
New	0	0	0	0	0	0	0	1	0	0	0	2	**3**
Closed	0	2	2	0	0	0	0	1	0	0	0	0	**41**
Open at End of Month	4	0	0	0	0	0	0	0	0	0	0	2	

4.9 Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-4. Service Interruptions per Month

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total*
No./Month	2	2	2	2	2	0	1	1	3	1	1	0	17

* 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 sole DOT reportable incident in 2010 was not caused by incorrect operations.

There were 2 ROW near misses reported in 2010 as part of the TPD Annual Assessment and as individual internal incident investigations.

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

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

The number of One-Call violations is also summarized as part of the TPD Annual Assessment. In 2010 there was a single One-Call violation, the same as 2009.

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

The number of TPD near misses for 2010 was two. These were taken from the 2010 TPD Annual Assessment and Annual Scorecard. 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
Tier 2			1										1
Tier 3													0
Total	0	0	2	0	0	0	0	0	0	0	0	0	2

Unauthorized ROW Encroachments (Item 52)

There was one (1) unauthorized ROW encroachments documented in the 2010 TPD Annual Assessment, which was located in a Tier 2 Risk Zone

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

One-Call violations are defined on a state-by-state basis. For the Longhorn ORA they are defined by the Texas Underground Facility Damage Prevention and Safety Act as referenced in the 2009 TPD Annual Assessment. Of the two near misses on the pipeline in 2010 both were classified as One-Call violations 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 2009 TPD Annual Assessment shows an 12-percent drop in Non-Company activity level from unique aerial patrol observations. This is primarily due to a decrease in housing development, and misc TP activity.

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

Total possible mileage includes the 694 mile main line plus the 29-mile lateral from Crane to Odessa and the lateral from El Paso Terminal to Diamond Junction. Tier III and Tier II areas must be inspected every 2½ days not to exceed 72 hours. The Tier I area from the Pecos River to El Paso only needs to be inspected once per week (not to exceed 12 days). Daily patrols are also required over the Edwards Aquifer Recharge Zone with one patrol per week to be a ground-level patrol. In an attempt to meet this requirement through aerial patrols, the pipeline ROW was flown daily from the Pecos River to Galena Park. Regular ground patrols were made in 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	31	34	17	25	17	14	14	14	14	11	14	20	224
Galena Park to Crane	11,954	11,021	12,638	12,887	14,646	14,719	13,375	16,085	14,571	14,779	15,006	14,604	166,285
Crane to El Paso	1,056	1,056	1,056	1,215	940	1,056	1,320	1,056	1,320	1,056	1,056	1,349	13,536
Total	**13,044**	**12,111**	**13,716**	**14,130**	**15,603**	**15,789**	**14,709**	**17,155**	**15,905**	**15,846**	**16,076**	**15,973**	**180,045**

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas from the Galena Park to Pecos River at least every 72 hours for almost the entire year. There were episodes of bad aerial patrol weather where ground patrols were organized to complete or in an attempt to complete the necessary patrols.

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

The number of pipeline markers repaired or replaced is 291 and comes from the TPD Annual Assessment. This is a 37-percent decrease from 2009. 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	39	6	43	62	73	32	22	11	1	0	1	1	291

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
Emergency Responder / Excavator Meetings	14	12	11	11	11	11
School Program:						
School Program - Houston	2	2	3	4		6
School Program - Austin	3	2	7	3	4	3
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**	**36**

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 2010 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	356	354	514	477	435	505	428	458	531	463	408	348	5277
II	333	315	428	454	353	384	343	362	343	331	337	282	4265
III	71	66	91	93	72	80	72	75	70	67	66	60	883
Total	**760**	**735**	**1033**	**1024**	**860**	**969**	**843**	**895**	**944**	**861**	**811**	**690**	**10,425**

Public Awareness Summary Annual Report (Item 60)

- The Public Awareness Summary Report for 2010 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	132	118	128	97	87	79	95	73	87	112	77	67	1152
– Call Before You Dig	35	46	53	25	39	29	44	26	48	47	39	78	509
– Pipeline Safety	81	100	74	54	59	69	9	40	93	98	67	46	790
– System Integrity Plan	67	68	61	61	51	55	63	53	65	68	53	42	707
– Longhorn Info.	188	317	263	230	311	186	299	234	318	290	267	239	3142
– Pipeline Emergencies	19	41	25	16	21	30	24	18	20	18	18	24	274
– Call Before You Dig Video	0	0	0	0	0	0	0	0	0	0	0	0	0
Home Page – 811 Logo	4	2	6	13	2	1	4	2	1	1	1	4	41
Total	**526**	**692**	**610**	**496**	**570**	**449**	**538**	**446**	**632**	**634**	**522**	**500**	**6615**

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	2	4	23	7	6	23	9	7	6	12	4	4	107
Unauthorized			1										1
Total	**2**	**4**	**24**	**7**	**6**	**23**	**9**	**7**	**6**	**12**	**4**	**4**	**108**

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

No physical hits to the pipeline were reported in 2010, the same as in, 2009, 2008, 2007, and 2006.

Annual TPD Assessment Report (Item 71)

The Longhorn System 2010 Annual Third Party Damage Prevention Program Assessment (TPD Annual Assessment) was received June 10, 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 of the 10,811One-Call notifications 12.2 percent required filed locates (marking of the pipeline location in the field). This is a 5.1 percent increase over 2009 when 7.1 percent of the 13,242 One-Call notifications required field locates. Note: the total differs slightly from the total in Item59 (One-Calls by Tier) because 386 One-Calls from the Odessa lateral are included in Table B-12 below.

Table B-12. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	301	73	787
Feb	302	55	763
Mar	410	86	1060
Apr	347	123	1063
May	255	100	888
Jun	230	136	1008
Jul	237	148	886
Aug	165	130	921
Sep	213	158	970
Oct	171	166	905
Nov	202	84	850
Dec	183	59	710
Totals	3016	1318	10811

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 only one incident that required a report to DOT/PHMSA, a leak from an improperly installed stem in a prover valve at Crane station which caused a seal leak and a spill quantity of 10 gallons.

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

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

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

ADB-10-08
Nov 3, 2010
PHMSA-2010-0307

Title: Pipeline Safety: Emergency Preparedness Communications

Summary: PHMSA is issuing an Advisory Bulletin to remind operators of gas and hazardous liquid pipeline facilities that they must make their pipeline emergency response plans available to local emergency response officials. PHMSA recommends that operators provide their emergency response plans to officials through their required liaison and public awareness activities. PHMSA intends to evaluate the extent to which operators have provided their emergency plans to local emergency officials when PHMSA performs future inspections for compliance with liaison and public awareness code requirements.

ADB-10-06
Aug 3, 2010

Title: Pipeline Safety: Personal Electronic Device Related Distractions

Summary: PHMSA is issuing an Advisory Bulletin to remind owners and operators of natural gas and hazardous liquid pipeline facilities of the risks associated with the use of personal electronic devices (PEDs) by individuals performing operations and maintenance activities on a pipeline facility.

ADB-10-05
Jun 23, 2010
PHMSA-2010-0175

Title: Pipeline Safety: Updating Facility Response Plans in Light of the Deepwater Horizon Oil Spill

Summary: PHMSA is issuing an Advisory Bulletin to operators of hazardous liquid pipeline facilities required to prepare and submit an oil spill response plan under 49 CFR part 194. In light of the Deepwater Horizon oil spill in the Gulf of Mexico, which has resulted in the relocation of oil spill response resources to address the oil spill, PHMSA is reminding operators of their responsibilities to review and update their oil spill response plans and to comply with other emergency response requirements to ensure the necessary response to a worst case discharge from their pipeline facility.

ADB-10-04
Apr 29, 2010

Title: Pipeline Safety: Implementation of Electronic Filing for Recently Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems

Summary: This notice advises owners and operators of gas pipeline facilities and hazardous liquid pipeline facilities that the new incident/accident report forms for their pipeline systems are now available for electronic filing.

ADB-10-03
Mar 24, 2010

PHMSA-2010-0078 Pipeline Safety: Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe

Summary: PHMSA is issuing an advisory bulletin to notify owners and operators of recently constructed large diameter natural gas pipeline and hazardous liquid pipeline systems of the potential for girth weld failures due to welding quality issues. Misalignment during welding of large diameter line pipe may cause in-service leaks and ruptures at pressures well below 72 percent specified minimum yield strength (SMYS). PHMSA has reviewed several recent projects constructed in 2008 and 2009 with 20-inch or greater diameter, grade X70 and higher line pipe. Metallurgical testing results of failed girth welds in pipe wall thickness transitions have found pipe segments with line pipe weld misalignment, improper bevel and wall thickness transitions, and other improper welding practices that occurred during construction. A number of the failures were located in pipeline segments with concentrated external loading due to support and backfill issues. Owners and operators of recently constructed large diameter pipelines should evaluate these lines for potential girth weld failures due to misalignment and other issues by reviewing construction and operating records and conducting engineering reviews as necessary.

ADB-10-02
Feb 3, 2010

PHMSA-2008-0211: Pipeline Safety: Implementation of Revised Incident/Accident Report Forms for Distribution Systems, Gas Transmission and Gathering Systems, and Hazardous Liquid Systems

Summary: This notice advises owners and operators of gas pipeline facilities and hazardous liquid pipeline facilities that the incident/accident report forms for their pipeline systems were recently revised and should be used for all incidents and accidents occurring on or after January 1, 2010. Forms are available here: http://phmsa.dot.gov/pipeline/library/forms.

The Incident/Accident Report Forms revisions make the information collected more useful to all those concerned with pipeline safety and provide additional, and in some instances, more detailed data for use in the development and enforcement of its risk-based regulatory regime. The failure cause categories are expanded and there is improved information on other aspects of the incidents.

ADB-10-01
Jan 26, 2010

Summary: The Pipeline and Hazardous Materials Safety Administration (PHMSA) is issuing this Advisory Bulletin to advise and remind hazardous liquid pipeline operators of the importance of prompt and effective leak detection capability in protecting public safety and the environment.

ADB-09-04
Jan 14, 2010

PHMSA-2009-0408; Pipeline Safety: Pipeline Safety: Reporting Drug and Alcohol Test Results for Contractors and Multiple Operator Identification Numbers
ADB-09-04

Summary: This notice advises operators of gas, hazardous liquid, and carbon dioxide pipelines and liquefied natural gas facilities that the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), is modifying the Drug & Alcohol Management Information System (DAMIS) to allow the reporting of contractor data without duplication and will begin collecting annual drug and alcohol testing data for contractor employees with Management Information System (MIS) reports due March 15, 2010. The collection of contractor MIS reports will provide data for the entire pipeline industry to calculate the required minimum annual percent rate for random drug testing. Operators will also identify all OPS issued operator identification numbers (OpID) covered by a MIS report of operator employees.

4.15 DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2010.

4.16 Literature Reviewed

See references.