Magellan Pipeline Company

Final Report No. 16-039

2014 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Harvey Haines, Adam Steiner,
Benjamin Wright, Fan Zhang, and Dennis Johnston

March 31, 2016

Kiefner

0010-1511

Intentionally blank

Final Report No. 16-039

Final Report

on

2014 Operational Reliability Assessment of the Longhorn Pipeline System

to

Magellan Pipeline Company

March 31, 2016

Prepared by

Susan Rose
Principal Engineer

Approved by

Carolyn E. Kolovich
Vice President, Pipeline

Kiefner and Associates, Inc.
4480 Bridgeway Avenue, Suite D
Columbus, OH 43219

0010-1511

DISCLAIMER

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Intentionally blank

TERMS, DEFINITIONS AND ACRONYMS

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

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

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

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

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

AC – Alternating Current

API – American Petroleum Institute

ASME – American Society of Mechanical Engineers

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

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

d – Defect depth

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

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

DOC – Depth of cover

DOT – Department of Transportation

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

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

EPA – Environmental Protection Agency

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

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

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

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

GPS – Global Positioning System – a method for locating a point on the earth using the GPS

HAZOP – Hazard and Operability (Study)

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

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

HIC – Hydrogen-induced Cracking

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

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

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

Incident – An event defined in the Incident Investigation Program of the LMP: Includes accidents, near-miss cases, or repairs, and/or any combination thereof. Incidents are divided into three categories, Major Incidents, Significant Incidents, and Minor Incidents.

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

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

L – Defect length

LFM – Low Field Magnetization

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

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

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

MASP – Maximum Allowable Surge Pressure

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

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

mil – One thousandth of an inch (0.001 in)

MOCR – Management of Change Recommendation

MOP – Maximum Operating Pressure

MP – Mile Post

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

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

New Pipeline – In 1998 extensions were added to the Existing Pipeline to make the current Longhorn pipeline. Extensions were added from Galena Park to MP 9 and Crane to El Paso Terminal. Laterals were added from Crane to Odessa, and from El Paso Terminal to Diamond Junction. In 2010 a 7-mile loop (3 ½ miles each way) was added, connecting Magellan's East Houston terminal to MP 6.

OD – Outside nominal diameter of line pipe.

One-Call – Texas 811 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 811 System can be reached at toll free number 811 or website http://www.texas811.org/.

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}.

Positive Material Identification Field Services – A process and procedure developed by T. D. Williamson to determine tensile strength, yield strength, and chemical composition on pipe in the field. The process includes mobile automated ball indention for mechanical properties and optical emission spectrometry for chemical composition.

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

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

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

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

RBDA – Reliability based design analysis

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 maximum defect depth (d) and overall 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

2014 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Harvey Haines, Adam Steiner, Benjamin Wright, Fan Zhang, and Dennis Johnston

1. INTRODUCTION

Objective

This report presents the annual operational reliability assessment (ORA) of the Longhorn Pipeline System for the 2014 operating year. Kiefner and Associates, Inc. (Kiefner) has carried out the ORA which is intended to provide Magellan with a technical assessment of the effectiveness of the Longhorn Pipeline System Integrity Plan (LPSIP). The technical assessment incorporates the results of all elements of the LPSIP as attributes and data to consider regarding the mechanical condition of the Longhorn assets. Recommendations are provided 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 U.S. Environmental Protection Agency (EPA) and the 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 conduct 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 start-up.

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

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

The activities of the ORA contractor consist of assessing pipeline operating data and the results of integrity assessments, surveys, and inspections, and making appropriate recommendations with respect to seven potential threats to pipeline integrity. Managing these threats and preserving the integrity of the Longhorn system assets are among the goals of the LPSIP being carried out by Magellan. The seven pipeline integrity threats are:

1. Pressure-Cycle-Induced Fatigue
2. Corrosion
3. Laminations and Hydrogen Blisters
4. Earth Movement and Water Forces
5. Third-Party Damage
6. Stress-Corrosion Cracking (SCC)
7. Threats to Facilities Other than Line Pipe

The sixth threat, SCC, has not been identified as a threat of concern to the Longhorn pipeline, but was added as SCC has been an unexpected problem for some pipelines, even though these pipelines had not recognized SCC as a threat in the past.

ORA Interaction with the LPSIP

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

The twelve elements of the LPSIP are:

1. Corrosion Management Plan
2. In-Line Inspection and Rehabilitation Program

3. Key Risk Areas Identification and Assessment
4. Damage Prevention Program
5. Encroachment Procedures
6. Incident Investigation Program
7. Management of Change
8. Depth of Cover Program
9. Fatigue Analysis & Monitoring Program
10. Scenario Based Risk Mitigation Analysis
11. Incorrect Operations Mitigation
12. System Integrity Plan Scorecarding and Performance Metrics Plan

Longhorn Pipeline System Description

During 2012 and 2013 the Longhorn system was split and a portion of the pipeline was reversed to begin shipping crude oil from Crane, TX to East Houston, TX. The flow reversal and displacement started on July 30, 2012 and was completed to Crane on August 17, 2012. The Longhorn systems went into service in April 2013 and are described below. The Longhorn System Map is presented in Figure 1 with a detailed map of the Houston area shown in Figure 2.

The first Longhorn system transports refined products from Odessa to El Paso, TX. The refined product system is made up of 29 miles of 8-inch pipe from Odessa to Crane Station, a 237-mile segment of 18-inch pipe from Crane Station to the El Paso Terminal in West Texas, and four 9.4-mile lateral pipelines connecting the El Paso Terminal to El Paso Junction (also known as the El Paso Laterals). Most of this pipe system was built in 1998.

The second Longhorn system transports crude oil over 424 miles of 18-inch pipeline from Crane Station to Satsuma Station with intermediate pumping stations at Texon, Barnhart, Cartman, Kimble, James River, Eckert, Cedar Valley, Bastrop, Warda, and Buckhorn. The crude system continues with 32 miles of 20-inch pipeline from Satsuma Station to the East Houston Terminal and nine miles of 20-inch pipeline from East Houston Terminal to 9th Street Junction. This second system contains all of the Existing Pipeline built in 1949-1950, with some replacements and extensions in the Houston area.

The only operational change in 2014 was an increase in flowrate from 225,000 bpd to 292,000 bpd from Crane to East Houston and an increase to 2,100 bph on the Western refinery connection at El Paso.

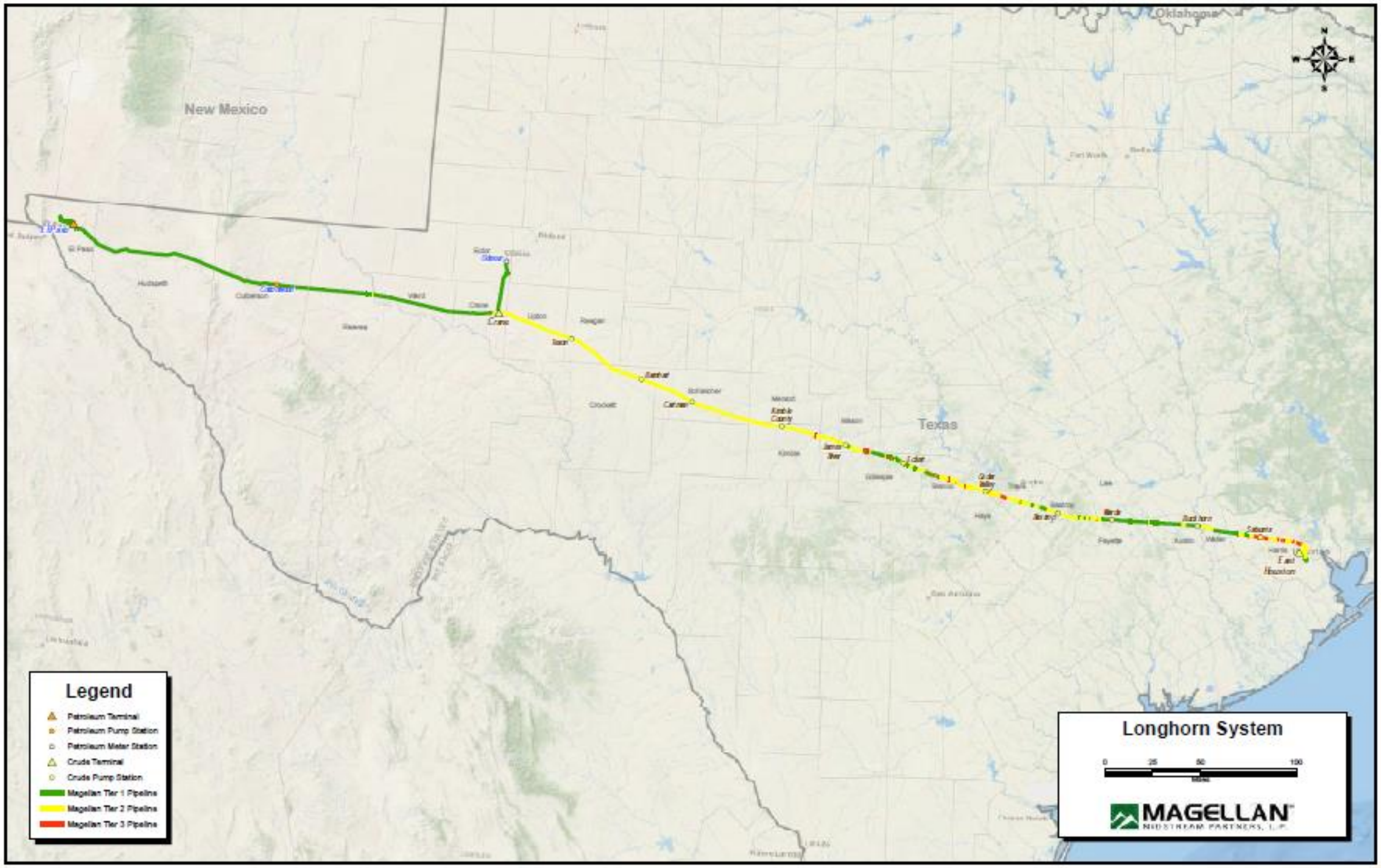

Figure 1. Longhorn System Map 2014

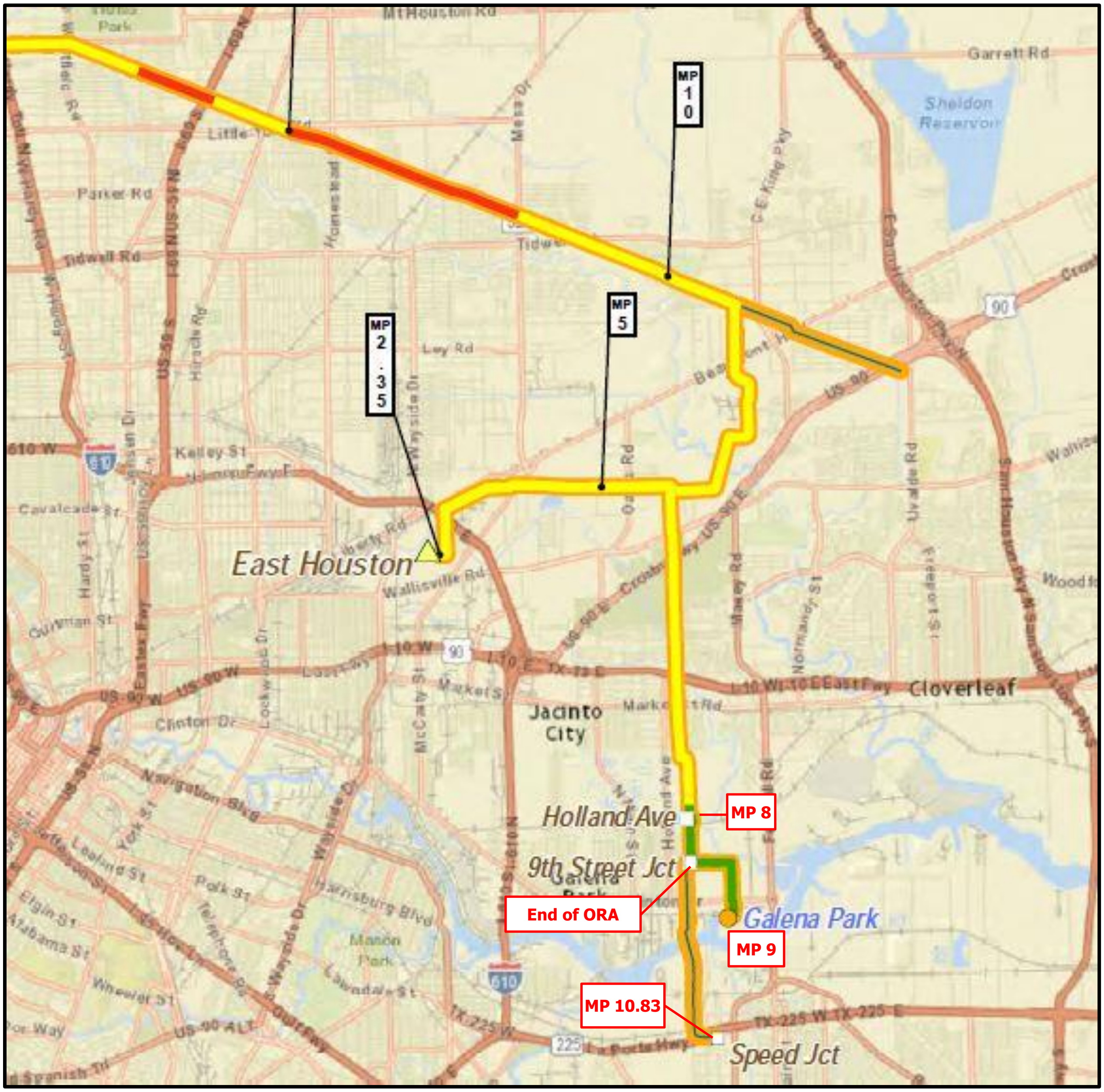

Figure 2. Map of Longhorn System within Houston Area

Time Scope

This report presents the annual assessment for 2014 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 2014 annual ORA report of the Longhorn system assets addresses the following subjects:

- Threats and Potential Threats to the Pipeline:
    1. Pressure-Cycle-Induced Fatigue
    2. Corrosion
    3. Laminations and Hydrogen Blisters
    4. Hard Spots
    5. Earth Movement and Water Forces
    6. Third-Party Damage
    7. Stress-Corrosion Cracking
    8. 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 aggressive in comparison to benchmark cycles 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 be necessary in the year 2019 for the Warda to Cedar Valley and Ft McKavett to Crane segments as discussed in section 5.1 of this report. A transverse field inspection (TFI) tool run, completed in 2007 and early 2008, was used to define a flaw size that determined the reassessment interval. Seventy-five (75) seam weld features were identified and remediated during the 2007 and 2008 program. Therefore, the reassessment interval used the seam weld feature detection threshold value from the TFI tool vendor.

Corrosion is a time dependent threat that is periodically monitored using in-line inspection (ILI), annual corrosion surveys, and close interval surveys (CIS). Ultrasonic (UT) wall measurement tools have been run from Galena Park to Crane and were completed in 2010. The next round of ILI assessments continued with the completion of one SpirALL magnetic flux leakage (SMFL) tool run in October 2014 for the 20-inch Satsuma to Speed Junction segment and one MFL tool run in December 2014 for the 18-inch Satsuma to Warda segment. Satsuma to Speed Junction was broken into two inspections: Satsuma to East Houston and East Houston to Speed Junction. (Note: Speed Junction to 9th Street Junction is not part of the ORA.) Satsuma to Warda was also broken into two inspections: Warda to Buckhorn and Buckhorn to Satsuma.

From the standpoint of earth movement and water forces, the primary integrity concerns are ground movement from aseismic faults and soil erosion caused by scouring from floods at specific points along the pipeline. As of 2014, 10.5 years of data of aseismic fault movements have been taken at four faults on Longhorn Partners Pipeline. The results show that fault movement on three of the faults continues to be so small that ground movement will not be a threat to the pipeline. The fourth fault at the Hockley site is a moderate threat based on the conservative estimation. An updated analysis of allowable fault displacement at the Hockley fault and recommended practices was conducted. Two and half years of data have been taken at three faults in East Houston Connection Pipeline. No movement above the measurement tolerance is detected. The allowable fault displacements at the three faults are also conducted. Semi-annual scour surveys of the crossings at the Colorado River and its tributary Pin Oak Creek are starting to show some evidence of soil erosion or scouring. These surveys need to be related to the remaining amount of cover for these two pipelines. The recommendation of conducting surveys of remaining depth of cover was made in March 2014 and should be completed in 2015. The remaining river crossings are inspected visually once every five years and were last inspected in 2010.

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. There were no cases of third-party contact with the pipeline and no right-of-way (ROW) near-misses during 2014. The absence of reportable incidents involving mainline pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial surveillance frequency) have been effective and are functioning as intended.

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

From the standpoint of facilities data acquired in 2014, one can conclude that pump station and terminal facilities had no adverse impact on public safety.

The technical assessment of the LPSIP indicates that Magellan is achieving the goal of the LPSIP, namely, to prevent incidents that would threaten human health or safety or cause environmental harm. In terms of activity measures, Magellan exceeded the goals of aerial surveillance and ground patrol in the total number of miles patrolled. In addition, public-awareness meetings were held, and right-of-way markers and signs were repaired or replaced where necessary. From the standpoint of metal loss deterioration measures, the number of anomalies requiring immediate repair was zero for the 2014 ILI runs. The number of metal loss anomalies found per mile requiring excavation is similar to previous UT ILI runs. In terms of failure measures, there were two DOT-reportable incidents; both releases occurred at pumping stations and the product was recovered. There was no third party contact with the pipe or facilities.

3. RECOMMENDATIONS

3.1. Technical Assessment of LPSIP Effectiveness

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

Longhorn Corrosion Management Plan

Internal corrosion is monitored using internal corrosion coupons. The coupon results have shown little change but monitoring should continue. One internal corrosion coupon was observed with a low corrosion rate (<0.06 mpy) on the 8-inch Crane refined line (see Table B-4). The cathodic protection system is monitored to look for areas where external corrosion could be occurring. The corrosion management plan, in combination with the ILI program, has been effective at preventing and monitoring corrosion degradation in 2014.

In-Line-Inspection and Rehabilitation Program

Two ILI assessments were conducted in 2014; one SMFL assessment on the 20-inch Satsuma to Speed Junction segment in October and one MFL assessment on the 18-inch Satsuma to Warda segment in December. Hard spot assessments using the MFL data occurred in 2013 and resulting inspection digs were made in 2014 at two locations located on the Eckert to Cedar Valley segment.

In general, the ILI surveys have been effective and have shown a decrease in the number of required repairs and thus an improvement in the condition of the pipe with each successive ILI run.

Damage Prevention Program

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. No events resulted in contact with the pipeline during 2014.

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

Encroachment Procedures

There were 88 encroachments recorded in 2014, none of which were unauthorized. The encroachment procedures, when followed by the encroaching party, have been effective at preventing TPD to the pipeline.

Incident Investigation Program

Magellan is performing incident investigations on all DOT reportable incidents as well as smaller non-reportable incidents. During 2014 there were 11 incident data reports filed; two were DOT Reportable (0.48 bbls refined product, 5.0 bbls diesel). Additional information is provided in Sections 4.10 and 4.11 (Appendix B).

Depth of Cover Program

One new exposure was identified in 2014 by the ROW maintenance crew. The location was found on a landowner's pasture where heavy water runoff had cut a channel and crossed the pipeline. The line was backfilled and grass seeded. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the SIP were repaired after additional erosion was found. Additionally, five road crossings were remediated with additional gravel cover, and one line lowering was completed on shallow pipe.

Thirteen (13) no-till agreements were renewed between Magellan and the landowners. As ongoing monitoring, landowners are contacted annually to reaffirm that cultivation techniques and land use has not changed. Magellan monitors this on a regular basis to ensure the landowner's farming practices do not jeopardize the integrity of the pipeline.

Fatigue Analysis and Monitoring Program

The 2014 fatigue analysis 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 2019 for the segment with the shortest time to failure was calculated based on the pressure cycles for 2008 through 2014 and using the results from the 2007-2008 TFI tool runs. The next assessments are as follows:

- East Houston to Satsuma (MP 0 to MP 34.1): 2031
- Satsuma to Warda (MP 34.1 to MP 112.9): 2020
- Warda to Cedar Valley (MP 112.9 to MP 181.6): 2019
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 2023
- Eckert to Ft McKavett (MP 227.9 to MP 321.9): 2022
- Ft McKavett to Crane (MP 321.9 to MP 457.5): 2019
- Crane to Cottonwood (MP 457.5 to MP 576.3): 2238

Corrosion

For the threat of corrosion, UT inspections for the Existing Pipeline were completed in 2010. Remediation was completed in 2010 and 2011. Four ILI runs occurred in 2014 over two Longhorn segments; the two segments were the 18-inch Satsuma to Warda and the 20-inch Satsuma to Speed Junction. The 18-inch Satsuma to Warda segment was broken into two runs: Satsuma to East Houston and East Houston to Speed Junction, using SMFL technology. The next required ILI assessments are as follows:

- Speed Junction to East Houston (MP 10.83 to MP 2.35): 2-Oct-2019
- East Houston to Satsuma (MP 2.35 to MP 34.1): 1-Oct-2019
- Satsuma to Warda (MP 34.1 to MP 112.9):
  - Satsuma to Buckhorn (MP 34.1 to MP 68.0): 18-Dec-2019
  - Buckhorn to Warda (MP 68.0 to MP 112.9): 16-Dec-2019
- Warda to Cedar Valley (MP 112.9 to MP 181.6): 24-Jan-2015
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 20-Feb-2015
- Eckert to Ft McKavett (MP 227.9 to MP 321.9): 25-Jun-2015
- Ft McKavett to Crane (MP 321.9 to MP 457.5): 8-Jul-2015
- Crane to Cottonwood (MP 457.5 to MP 576.3): 19-Nov-2018
- Cottonwood to El Paso (MP 576.3 to MP 694.4): 19-May-2017
- Crane to Odessa: 28-Jun-2016
- El Paso to Chevron 8-in (Line ID 6650): 23-Feb-2017
- Kinder Morgan 8-in Flush Line (Line ID 6652): 21-Feb-2017

- El Paso to Kinder Morgan 12-in (Line ID 6651): 22-Feb-2017

Laminations and Hydrogen Blisters

The change in the transported commodity from refined products to crude oil could potentially lead to an increased threat of hydrogen blistering. Managing internal corrosion will provide mitigation of this threat by minimizing the production of hydrogen that is produced by anaerobic corrosion. Blisters can form at laminations in the pipe wall. All injurious laminations identified in the 2010 UT tool run were repaired. As a future intervention method to prevent any existing non-injurious laminations from becoming injurious, Electronic Geometry (EGP) runs will be used to inspect for the formation of blisters at a lamination. These EGP tools are required to be run every three years in accordance with the LMP.

A review of the 2014 maintenance reports showed no lamination anomalies were excavated. Magellan should continue to monitor for blister formation or growth, or both, at laminations with ILI tools. Per Longhorn EA section 9.3.2.3 the monitoring frequency recommended should coincide with the electronic geometry pig (EGP) tool assessment schedule. Section 9.3.2.3 requires an EGP assessment every 3 years in accordance with the LMP. The deformations identified from these assessments will be correlated with the existing laminations found from the UT assessments.

- East Houston to Satsuma (MP0 to MP 34.1):
  - Speed Junction to East Houston (MP 10.83 to MP 2.35):
    - Speed Junction to 9th Street Junction is not part of the ORA (MP 10.83 to MP); a map of the Houston area is shown in Figure 2.
  - East Houston to Satsuma (MP 2.35 to MP 34.1)
- Satsuma to Warda (MP 34.1 to MP 112.9):
  - Satsuma to Buckhorn (MP 34.1 to MP 68.0)
  - Buckhorn to Warda (MP 68.0 to MP 112.9)
- Warda to Cedar Valley (MP 112.9 to MP 181.6)
- Cedar Valley to Eckert (MP 181.6 to MP 227.9)
- Eckert to Ft McKavett (MP 227.9 to MP 321.9)
- Ft McKavett to Crane (MP 321.9 to MP 457.5)

Earth Movement and Water Forces

The earth movement analysis continues to show that any movement on the seven faults that are monitored is an order of magnitude less than the assumptions used to justify the required monitoring program in the EA. Because of this slow rate of fault movement, Kiefner continues to recommend a five-year reassessment program for these seven faults rather than the current semi-annual program. If the faults appear to become more active, then more frequent measurements can be implemented. The movement at Hockley Fault is sufficiently active to raise some concern, in part because of the original assessment performed by Kiefner in 2004 which from reanalysis appears conservative, and in part because of the uncertainty of fault movement between 1950 and 2004 caused by a lack of fault displacement data. Remediation of additional studies is recommended within five years. Three potential paths for remediation are as follows.

Option 1: Excavate and expose the pipeline segment including three joints at each side of the fault within five years. From the distribution of longitudinal stress resulting from fault movement shown in Figure 11, the recommended excavation length is enough to release the majority of accumulated longitudinal stress. The pipe will then be restored to a state free of stress caused by fault movement. The pipe can resist an additional 1.25 inches of fault movement before the next excavation. It is also recommended to examine the quality of girth welds in the exposed segment using this opportunity.

Option 2: If there is an existing inertial pigging record or an internal pigging is scheduled in near future, the level of current accumulated stresses in the pipe can be estimated. It will then be used to determine an accurate value of the additional fault displacement that can be accommodated by pipe before failure.

Option 3: If no inertial pigging record is available and no dig is scheduled in the near future, a literature review should be conducted to determine the fault movement history at the location since the installation of the pipeline.

Scour inspections were completed in December 2014 on the Colorado River and Pin Oak Creek. Data from semi-annual scour inspections for the Colorado River and Pin Oak Creek were inconclusive because of water level fluctuations that were used for measurement. These measurements need to be related to the remaining depth of burial on the pipeline in the waterway so that Magellan can plan for any remediation that may be needed once an erosion threshold is reached (see Stream Crossings in Section 5.5). The scour inspection on these two crossings should continue 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 2014. Inspection activities include ILI assessments required per the ORA; using "Smart Geometry" tools and High Resolution MFL or UT tools. LMC 12A requires ILI assessments for TPD detection between Valve J1 and Crane Station be carried out within three years of a previous inspection. Two ILI assessments were conducted in 2014; one SMFL assessment on the 20" Satsuma to Speed Junction segment in October and one MFL assessment on the 18" Satsuma to Warda segment in December. For specific inspection dates to fulfill the requirement for each of the six intervals spanning the Existing Pipeline from East Houston to Crane see Table 11 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

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance. Process Hazards Analyses (PHAs) and Layer of Protection (LOPA) studies were conducted for the injection of DRA (drag reducing agent) at Satsuma and Bastrop Stations. PHAs were also conducted for the El Paso Terminal Revalidation and the Longhorn Expansion Project.

During 2014 there were eleven internal incident data reports filed; nine of the incidents occurred at facilities. Two of the eleven incidents were DOT Reportable, both of which occurred at facilities. One incident involved a release of approximately five barrels of diesel due to a combination of incorrect operation, faulty control logic, and inadequate operating procedures. The other involved in a release of approximately 20 gallons (.48 bbls) of refined product due to valves left open during pigging operations. Four of the nine facility incidents were due to incorrect operation; four were due to equipment failures; one was due to abnormal operations that required a procedure revision.

Although these incidents had no adverse impact on public safety, it is recommended that Magellan continue its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

3.3. Implementation of New Mechanical Integrity Technologies

During 2013, T. D. Williamson developed processes and procedures for the field determination of pipeline mechanical properties and chemical composition. The mechanical properties include pipe yield strength and pipe tensile strength. A detailed procedure and process manual developed by T. D. Williamson was reviewed. The process is termed "Positive Material Identification Field Services". The process includes mobile automated ball indention for mechanical properties and optical emissions spectrometry for chemical composition. The procedure is thorough and provides a guide for technicians to field test pipe without having to remove samples for laboratory testing. Verification testing was performed at Kiefner on 11 pipe samples that had been removed from the Longhorn Pipeline. Enhancements to the field process were made and tested during additional validation tests. The test results were presented to PHMSA by Magellan and T. D. Williamson.

Magellan has committed to conducting non-destructive or destructive strength tests for 50 percent of all annual pipe excavations associated with in-line inspection anomaly evaluations or remediation. The strength tests are only required where material documentation is not available. In 2014, two excavations associated with ILI anomaly investigations on the Eckert to Cedar Valley segment occurred. Strength testing was completed at one of the investigation locations to meet this requirement.

3.4. ORA Process Improvements

Longhorn should consider using a reliability-based design analysis (RBDA) to calculate the probability that a corrosion feature may fail by either perforation leak or plastic collapse, often simply referred to as leak or rupture. A leak failure is driven by a corrosion feature's depth while a rupture failure is driven by a corrosion feature's burst pressure. Currently Longhorn uses a probability of exceedance (POE) calculation. The ORAPM requires Longhorn to further analyze features with a POE equal to or greater than 1 x 10^{-7} for leak and rupture and grow those for five years with a best estimate of corrosion growth rate. Kiefner reports corrosion features with a POE greater than or equal to 1 x 10^{-5} for leak and rupture; these features are then inspected by bell hole excavations.

RBDA and POE calculations are two different approaches to calculating a corrosion feature's probabilistic integrity threat. POE assumes only one variation or error when calculating uncertainty of exceeding a safe threshold, i.e. feature depth ILI measurement error, whether the depth uncertainty is used in leak-failure or rupture-failure uncertainty. The ILI depth error is captured as a bias and tolerance when used in the POE calculation. Other parameters are fixed to be nominal or lower-bound values and the actual uncertainty or variability in these parameters is ignored. The RBDA calculation considers these uncertainties, including feature length, material strength, burst pressure or perforation leak model error, and corrosion growth rate uncertainty. For example, X42 grade pipe typically has strength values that fall in a range between 42,500 and 61,000 psi.

Kiefner has completed some preliminary comparisons between RBDA and POE, and RBDA appears to be a better risk model than POE. Our findings are that the RBDA calculation removes some conservatism inherent in the POE calculation and produces a more accurate probability that a feature could fail. The advantage of RBDA is that it incorporates the measurement uncertainty addressed by POE in addition to other uncertainties and provides a more comprehensive understanding about the various factors that can affect an integrity threat to the pipeline, whether those factors increase the probability of failure or provide additional protection mitigating the probability of failure. Our recommendation is to perform both RBDA and POE calculations on corrosion features for current ILI assessments in the 2015 ORA as a comparison and to consider using RBDA for other threat types in the future where feasible.

4. New Data Used in This Analysis

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

5. Results and Discussion of Data Analysis

This section presents an analysis of the data collected in Section 4 for the ongoing integrity threats monitored by the LMP: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, hard spots, earth movement, 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 flaws is recognized to be a potential threat to the integrity of the Longhorn Pipeline. Manufacturing flaws 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 flaw 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 potentially growing cracks before they become large enough to cause a failure of the pipeline. Although the likelihood of such flaws being present in the newer 1998, 2010, 2012 and 2013 pipe material is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses were considered for the New Pipeline (MP 9 to East Houston, Crane to El Paso, and piping added for the 2012 and 2013 reversal project) 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 flaw 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 flaw size. In this case, toughness is a factor for establishing starting flaw sizes and it is more conservative to use a higher value of toughness as it allows for a larger flaw to remain after the hydrotest. Note that toughness is not a factor in establishing either starting defect size using the ILI detection threshold or the N10 notch. Toughness is needed to calculate the size of the flaw 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 flaws. With a longer flaw, 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]), a readily available technical publication.

Pressure-cycle data is provided to us by Magellan. 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 flaw 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 1947 to 1953 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 flaw has a shorter life than a 25-percent through wall flaw. In the Existing Pipe, we assume the flaw 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 flaws detected by the TFI tool, we use a starting flaw size that is the largest flaw that could have escaped detection in the manufacturer's ultrasonic seam inspection. That would be the size of the "calibration" flaw 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 flaws 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 flaw 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.

The case locations were chosen with reference to the operating direction and pump locations as of November 2013. The analysis was completed in three sets to reflect the configurations of the pipeline during the 2007-2014 time period. The first analysis set used the 2007 to 2012 data to represent the operations since start-up and flow from east to west. The second analysis covered the time period between April 2013 to October 2013 in which the crude portion of the pipeline was operating from Crane to East Houston, and only a limited number of pumps were operating. The final analysis was completed using the November 2013 to December 2014 data, in which the line was operating in its fully reconfigured format and all pumps were in operation.

Our analysis shows that the shortest time to failure for a possible feature that could have been missed by the TFI tool is 11.5 years at the location that is now the Texon Station 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 5.2 years based on the current operating pressures. An assessment would be required in 2019 for the Warda to Cedar Valley and Ft McKavett to Crane segments. Assessments for the other segments would be required between 2020 and 2238, as stated in Section 3.2. The reversal of the pipeline from Crane to East Houston combined with the addition of pumping stations has increased the cycling intensity and frequency.

Table 1 summarizes the locations evaluated. The pressure data from 2007 to October 2013 were applied for a period of 12.4 years to include the actual time of operation multiplied by the factor of safety of 2.22 so that distortions to the remaining fatigue life and reassessment interval would be minimized. The November and December 2013 pressure data were applied to the depths and lengths obtained after applying the 2007 through October 2013 pressure data to determine the remaining life from that point in time. Therefore, the fatigue lives shown in Table 2 are to be taken from the November 2013 date. The factor of safety should be applied to these fatigue lives to determine the reassessment interval. As the Crane to El Paso products segment of the line operates separately from the Crane to East Houston segment, results for that segment may be considered separately. A fatigue life was calculated for the new 1998 pipe at Crane Station on the products line based on the maximum flaw size, described above as an API 5L N10 notch, a 10-percent, 2-inch-long flaw. Our analysis shows that the shortest time to failure for this segment is greater than 500. This would result in a reassessment interval of a minimum of 225 years.

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

Case	Description	Seam Type	Manufacturer	Station	Mile Post	Diameter, inches	Wall Thickness, inch	Pipe Grade
1	1947 Pipe near Satsuma Discharge	ERW-LF	UNKNOWN	1799+54	34.1	20	0.312	Grade B
2	1950 Pipe near Buckhorn Discharge	EFW	A.O. SMITH	3587+73	67.9	18	0.281	X45
3	1950 Pipe near Warda Discharge	EFW	A.O. SMITH	5960+75	112.9	18	0.281	X45
4	1950 Pipe near Bastrop Discharge	EFW	A.O. SMITH	7487+53	141.8	18	0.281	X45
5	1950 Pipe near Cedar Valley Discharge	EFW	A.O. SMITH	8402+75	159.1	18	0.312	X45
6	1950 Pipe near Eckert Discharge	EFW	A.O. SMITH	12032+98	227.9	18	0.281	X45
7	1950 Pipe near James River Discharge	EFW	A.O. SMITH	13736+94	260.2	18	0.281	X45
8	1950 Pipe near Kimble Discharge	EFW	A.O. SMITH	15585+45	295.2	18	0.281	X45
9	1950 Pipe near Cartman Discharge	EFW	A.O. SMITH	18212+02	344.9	18	0.281	X45
10	1950 Pipe near Barnhart Discharge	EFW	A.O. SMITH	19354+32	366.6	18	0.312	X45
11	1953 Pipe near Texon Discharge	EFW	A.O. SMITH	21998+56	416.6	18	0.250	X52
12	1953 Pipe near Crane Crude Discharge	EFW	A.O. SMITH	24060+69	455.7	18	0.250	X52
13	1998 Pipe near Crane Products Discharge	ERW-HF	U.S. STEEL	24160+18	457.6	18	0.281	X65
14	1947 Pipe at Cedar Valley Discharge	EFW	A.O. SMITH	8963+66	169.8	18	0.281	X45

Table 2 depicts the fatigue life for each of the above locations. The reassessment interval is based on the remediation of all cracks detectable by the TFI, a high probability of detection for TFI finding all features greater than 50-percent deep and 2-inches long, and no feature greater than 10 percent of the wall thickness existing in the new pipe and the factor of safety of 2.22.

Table 2. Fatigue Lives and Re-assessment Intervals for Analysis Locations

Case	Cycles per Year	Calculated Time to Failure since Nov 2013, years	Re-assessment Interval, years	Re-assessment Interval Safety Factor	Re-assessment Year
1	3,707	38.5	17.3	2.22	2031
2	3,521	30.3	13.7	2.22	2027
3	3,602	14.7	6.6	2.22	2020
4	7,704	11.9	5.3	2.22	2019
5	2,776	49.6	22.4	2.22	2036
6	3,318	21.7	9.8	2.22	2023
7	3,409	18.6	8.4	2.22	2022
8	1,234	53.0	23.9	2.22	2037
9	3,134	14.7	6.6	2.22	2020
10	2,696	33.8	15.2	2.22	2029
11	***2,863***	***11.5***	***5.2***	***2.22***	***2019***
12	2,366	13.1	5.9	2.22	2019
13	2,452	23.7	225.2	2.22	2238
14	2,994	30.2	13.6	2.22	2027

5.2. Corrosion

Monitoring the Possibility of Corrosion-Related Leaks using ILI

ILI results are commonly used by pipeline operators as a means for identifying and evaluating corrosion-caused metal loss and planning remediation. This typically involves running an ILI tool to identify and size corrosion features followed by remediation of features that exceed a depth or a pressure threshold as necessary. This generally accepted method is a valid approach for addressing line pipe corrosion. Non-destructive testing of pipe segments in at least 50% of the excavations or remediations required by ILI results started in 2014 for pipe where material documentation is not available, as required by the Material Documentation Plan noted in section 5.5 in the 2013 Self-Audit. In 2014, two excavations associated with ILI anomaly investigations on the Eckert to Cedar Valley segment occurred. Strength testing was completed at one of the investigation locations to meet this requirement. In 2014 MFL tools were run on two pipeline segments from Satsuma to Speed Junction and Satsuma to Warda.

Satsuma to Speed Junction was broken into two inspections; Satsuma to East Houston and East Houston to Speed Junction. Note: Speed Junction to 9th Street Junction is not part of the ORA.

ILI Inspections

Ultrasonic wall measurement tools were run on the six segments from Galena Park through Crane beginning in 2009 with completion in 2010. The 2014 round of inspections were run using MFL and geometry tools, providing information on metal loss (internal and external) and dents. Magellan will be performing validation digs on the 2014 MFL runs in 2015. Table 3 shows, per pipeline segment, the anomalies that were remediated in 2014.

Table 3. Summary of Anomalies Remediated in 2014

Pipeline Segment	Anomalies Excavated	Hard Spots Excavated
20” Galena Park to Satsuma	0	0
18” Satsuma to Warda	0	0
18” Warda to Cedar Valley	0	0
18” Cedar Valley to Eckert	2	2
18” Eckert to Fort McKavett	0	0
18” Fort McKavett to Crane	0	0
18” Crane to Cottonwood	2	0
18” Cottonwood to El Paso	1	0
8” El Paso to Chevron	0	0
8” Kinder Morgan to Flush Line	0	0
12” El Paso Kinder Morgan	0	0

External corrosion growth rates were determined by correlating the 2006 MFL data and the MFL data from the two 2014 ILI assessments, 18-inch Satsuma to Warda and 20-inch Satsuma to East Houston. For the 18-inch Satsuma to Warda segment the observed upper bound corrosion growth rate averaged 6.2 mils per year (mpy). For the 20-inch Satsuma to East Houston segment the observed upper bound corrosion growth rate averaged 3.7 mpy. Data correlation and calculations were done using Kiefner’s LaserSure™ software.

The population distribution of the metal loss (+) or metal gain (-) (ML or MG) used to calculate corrosion growth rates were evaluated as the population frequency histogram shown in Figure 3 for the Satsuma to Warda segment. Assuming a normal distribution for the ML vs MG population the bias in the distribution mean represents either the average corrosion growth rate for the entire ILI run or it may indicate an ILI error. Figure 3 shows the goodness of fit for a normal distribution for features from the 2014 ILI assessment with a depth greater than 12%wt. Metal loss features with depths of 10 and 11%wt from the 2014 ILI assessment were not included in the CGR analysis due to the uncertainty of the accuracy of the 2006 assessment depths for these features.

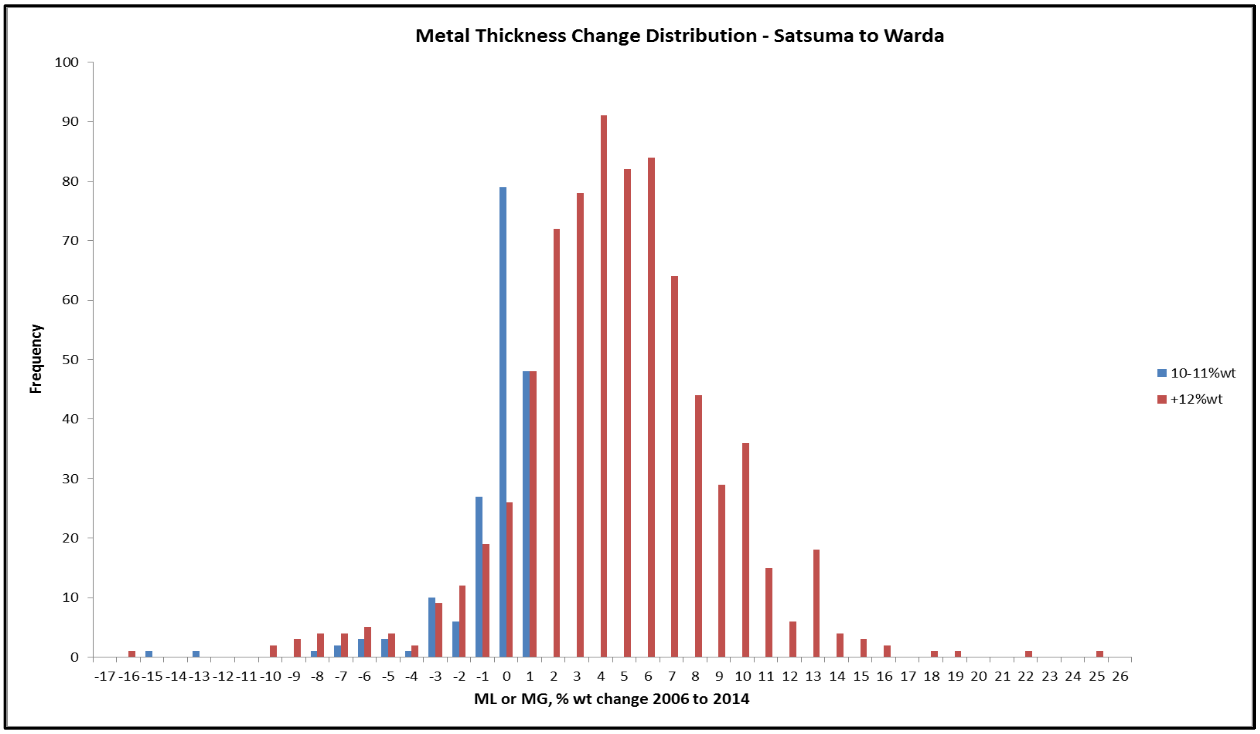

Figure 3. Satsuma to Warda Histogram showing the distribution of metal loss/metal gain obtained from the 2006 to 2014 run comparison (953 data points)

External corrosion growth rates along a pipeline should be expected to have the potential for variability along the length of pipeline due to differences in cathodic protection, coating conditions, pipe age, and environment. A histogram of metal loss frequency (occurrences or count) along the linear distance of the pipeline can give indication where metal loss features are more likely. A comparison of metal loss frequency histograms for the 2006 MFL assessment and the 2014 MFL assessment can be seen in Figure 4 for the Warda to Satsuma segment and in Figure 5 for the Satsuma to East Houston segment. Note, in Figure 4 and Figure 5 external metal loss features with depths less than 12%wt were excluded from the 2014 data. Both segments inspected in 2014 had a large amount of low metal loss features (less than 12%wt); Warda to Satsuma (2,155) and Satsuma to East Houston (1,904). A couple of possible explanations for the large amount of low metal loss features could be due to advancements in tool technology or could be that features were just below the 10%wt threshold in 2006 and are now just above the 10%wt threshold in 2014.

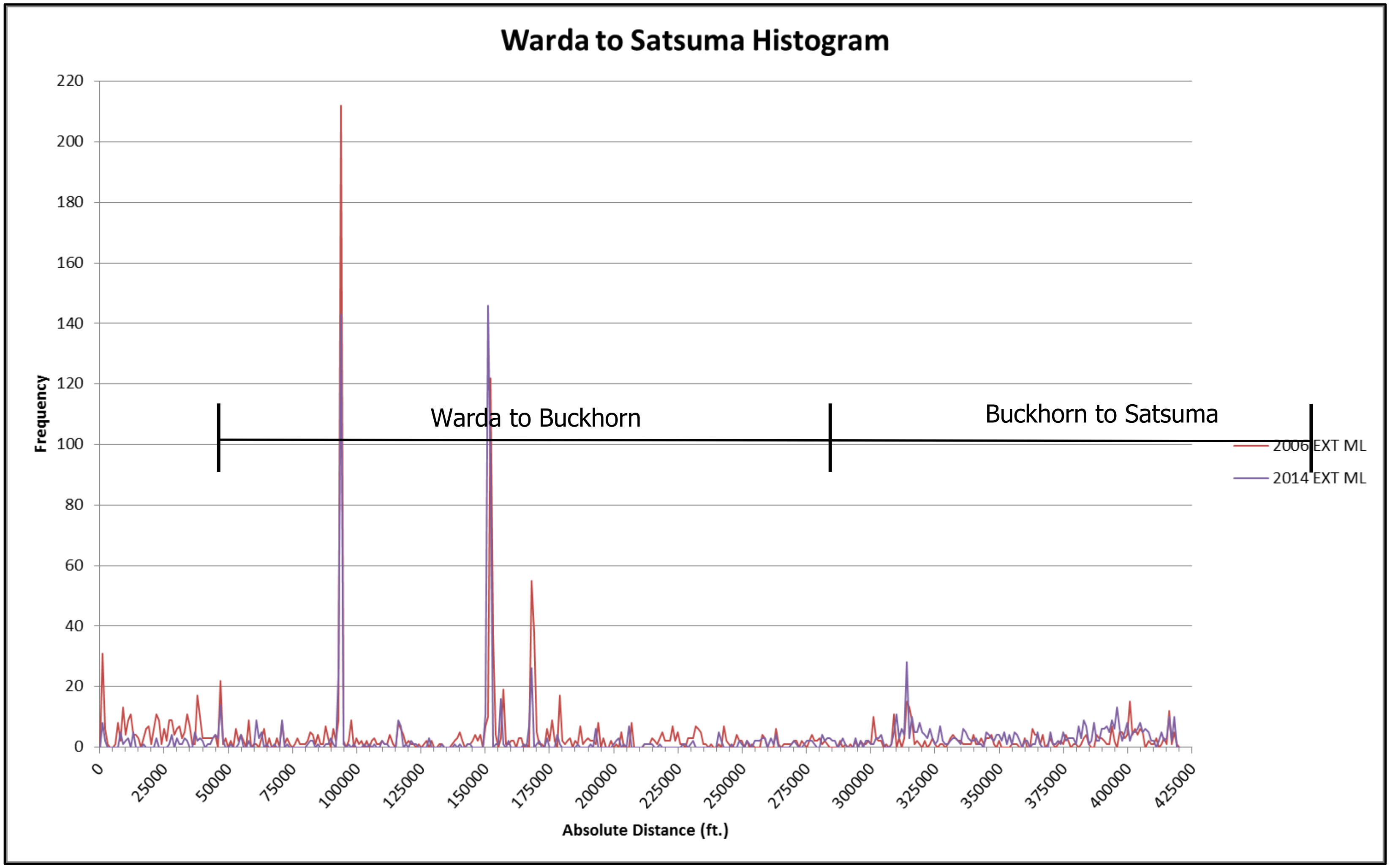

Figure 4. Warda to Satsuma metal loss frequency by linear distance along the pipeline (2006 MFL vs 2014 MFL data)

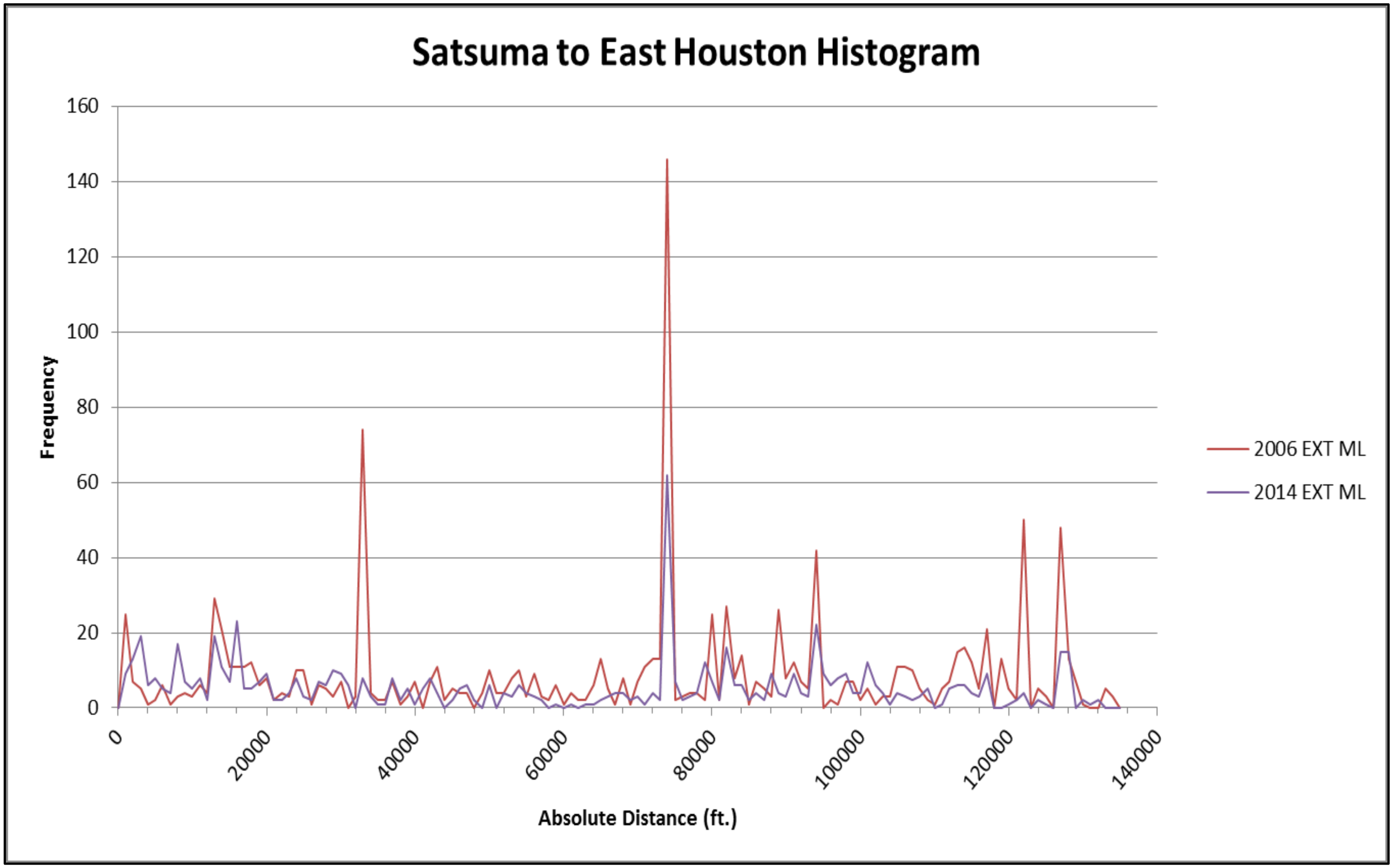

Figure 5. Satsuma to East Houston metal loss frequency by linear distance along the pipeline (2006 MFL vs 2014 MFL data)

5.3. Pipe Laminations and Hydrogen Blistering

No laminations or hydrogen blisters were excavated in 2014. The conversion of the pipeline to crude oil service in 2013 re-introduced trace amounts of hydrogen sulfide to the pipeline, similar to the crude oil that was transported from the early 1950's until 1995. Monitoring of the lamination anomalies for the possibility of blister growth with ILI tools is recommended per the proposed Longhorn Pipeline Reversal EA Section 6.2.1.2. Deformation results from the ILI tool runs were compared to the locations of laminations identified by the 2009-2010 UT runs. No deformations and laminations were correlated between the MFL and the UT runs. Deformations that form at the location of laminations may be an indication of blister formation.

5.4. Hard Spots

Magellan has committed to running a hard spot tool and remediating indications where pipe is susceptible to hard spots (over 325 Brinell hardness) based upon known pipe information (i.e. manufacturing vintage and has had a past leak or failure due to a pipe hard spot in the pipeline) as soon as practical but not later than one year after the hard spot tool run. Hard spots are formed during the manufacturing process due to local rapid cooling of the steel plate surface in the hot rolling mill that creates metallurgical changes. The conversion of the pipeline to crude oil service in 2013 re-introduced trace amounts of hydrogen sulfide into the pipeline which could be detrimental, as hard spots (particularly those with hardness exceeding 35 on the Rockwell C scale) can be susceptible to hydrogen induced cracking (HIC).

In 2013 a combination MFL and Low Field Magnetization (LFM) tool was run from Crane to East Houston to identify possible hard spot features in the pipe body (see Table 4 for 2013 inspection results). The Eckert to Cedar Valley segment results reported two hard spots that were both rated 1 on a scale from 1 to 5; 5 being most likely and 1 being improbable. Both hard spots on the Eckert to Cedar Valley segment were investigated in 2014; no anomaly was found in either location and both locations were recoated and backfilled.

Table 4. Summary of Hard Spots Detected

			Hard Spot Scale				
Pipeline Segment	**Date**	**Possible Hard Spots Identified**	**5 Most Likely**	**4**	**3**	**2 Questionable**	**1 Improbable**
Crane to Texon	10/15/2013	0	0	0	0	0	0
Texon to Barnhart	10/16/2013	0	0	0	0	0	0
Barnhart to Cartman	10/18/2013	0	0	0	0	0	0
Cartman to Kimble	10/22/2013	0	0	0	0	0	0

			Hard Spot Scale				
Pipeline Segment	**Date**	**Possible Hard Spots Identified**	**5 Most Likely**	**4**	**3**	**2 Questionable**	**1 Improbable**
Kimble to James River	10/23/2013	0	0	0	0	0	0
James River to Eckert	10/24/2013	0	0	0	0	0	0
Eckert to Cedar Valley	11/11/2013	2	0	0	0	0	2
Cedar Valley to Bastrop	12/3/2013	0	0	0	0	0	0
Bastrop to Warda	10/30/2013	0	0	0	0	0	0
Warda to Buckhorn	11/1/2013	0	0	0	0	0	0
Buckhorn to Satsuma	12/4/2013	0	0	0	0	0	0
Satsuma to East Houston	8/28/2013	0	0	0	0	0	0

5.5. Earth Movement (Fault and Stream Crossings)

Fault Crossings

The Longhorn Pipeline System crosses several aseismic faults between Harris County and El Paso, TX. None of the faults west of Harris County are known to be active. Within Harris County, the pipeline crosses seven aseismic faults that are considered to be active. The location and geologic data concerning Akron, Melde, Breen, and Hockley are summarized in Table 5.

Table 5. Fault Location and Geologic Data for Akron, Melde, Breen and Hockley Aseismic Faults in Harris County, TX

	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 four 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. Twenty-one subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the vertical displacements over time is shown in Figure 6 below. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. Using 11 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 0.014 in/yr (0.36 mm/yr) over 10½ years for the Akron Fault and -0.022 in/yr (-0.56 mm/yr) over 10½ years for the Hockley Fault.

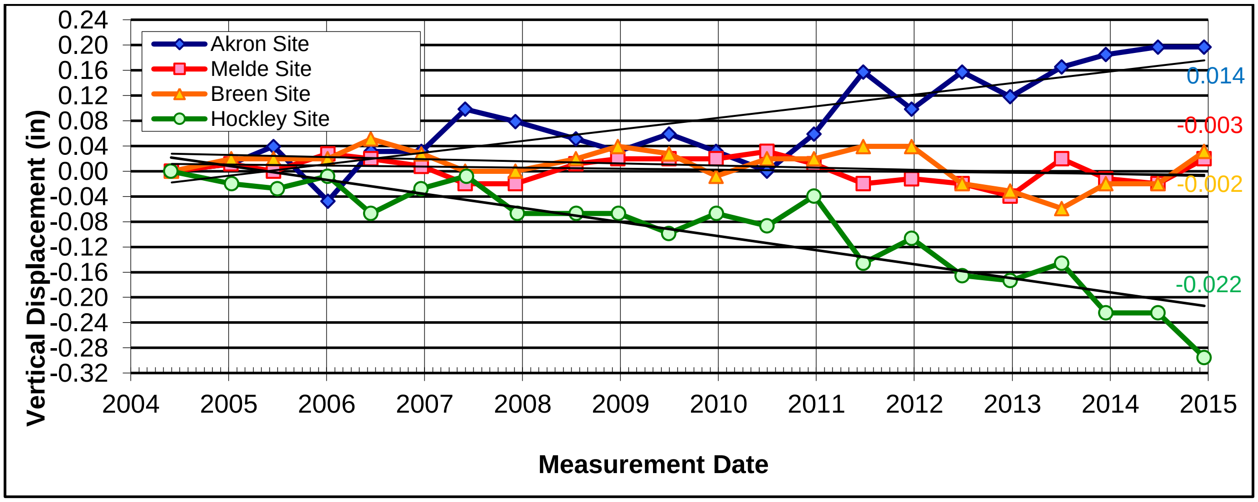

Figure 6. Fault Displacement over 11-Year Period at Akron, Melde, Breen and Hockley Faults

For this year's analysis of 11 years of data, we used the calculated movement from the best fit trend lines and compared these estimates of fault growth to the Kiefner stress analysis described in the 2005 ORA Annual Report. Assumptions used in the 2005 analysis included: the allowable stress levels based on the latest version of ASME B31.4 available at that time; the stress resulting from regular operation (instead of fault movement) in the pipeline was determined by ASME B31.4 stress analysis; the soil properties were from our best estimate for representative values of properties obtainable and the fault movement rates were represented by linear trend lines fit to the data. Table 7 shows the amount of movement at each fault that can occur before it exceeds the stress levels determined by the 2005 analysis. The differences in allowable fault displacements are caused in a large part by differences in the angles of the fault movement. The calculated rate of displacement has accelerated and reduced the number of years to reach the allowed displacement from the amount reported in the first half of 2013 Report (Table 6). It should be noted that the "time to reach displacement (yrs)" in the last column is the total time from when the pipe is free of stress resulting from fault movement to the final failure. The limited number of years for Hockley Fault fell below the life of the pipeline segment at the region which was installed in the 1950s. If the fault has moved at an average rate of 0.022 in/yr since the installation, the stress should have failed according to the criterion from 2005 analysis. An updated analysis, criterion, and recommendations at Hockley Fault are provided at the end of this section. The other three faults have reinspection times of 250+ years. Such long times to reach a displacement that could result in failure would normally not warrant any monitoring. However, according to the U.S. Geological Survey of September 2005 (Reference [4]) there are documented cases of fault movement reinitiating, so monitoring every five years for these three faults is also appropriate.

Table 6. Summary of Estimated Allowable Fault Displacement at Akron, Melde, Breen and Hockley Faults

	Allowable Displacement (in)	Ave. Rate of Movement (in/yr)	Time to Reach Allowable Displacement (yrs)
Akron	4.17	0.014	298
Melde	4.13	-0.003	> 1000
Breen	1.50	-0.002	750
Hockley	0.63	-0.022	29

Section 6.4 on Aseismic Faulting/Subsidence Hazards in Appendix 9E of the Environmental Assessment (Reference [5]) estimated the rates of vertical movement on the order of 0.20 inch per year based on field observations. Actual measurements over the past 11 years show rates that are more than an order of magnitude less than the 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 high enough that semi-annual monitoring is much more often than needed.

Three additional faults have been instrumented for the lines that were constructed to connect the existing Longhorn line to East Houston in 2012. The three faults include the McCarty Fault near Station 35+80, Negyev Fault near Station 140+00, and Oates Fault near Station 147+00. Baseline readings were taken for the McCarty, Negyev, and Oates faults in September 2012. After the baseline readings there have been five readings performed within approximately one year as shown in Figure 7. The trend line for Negyev and Oates show no movements. At the McCarty Fault, there is a significant jump of about ½ inch between the baseline reading and the first reading point; no movement was observed from the readings after the first reading point. As a result, the jump at the first reading point is very likely due to the false baseline reading. The allowable fault displacement at the three faults was determined as described below which would provide monitoring references as those listed in Table 4 for the other four faults.

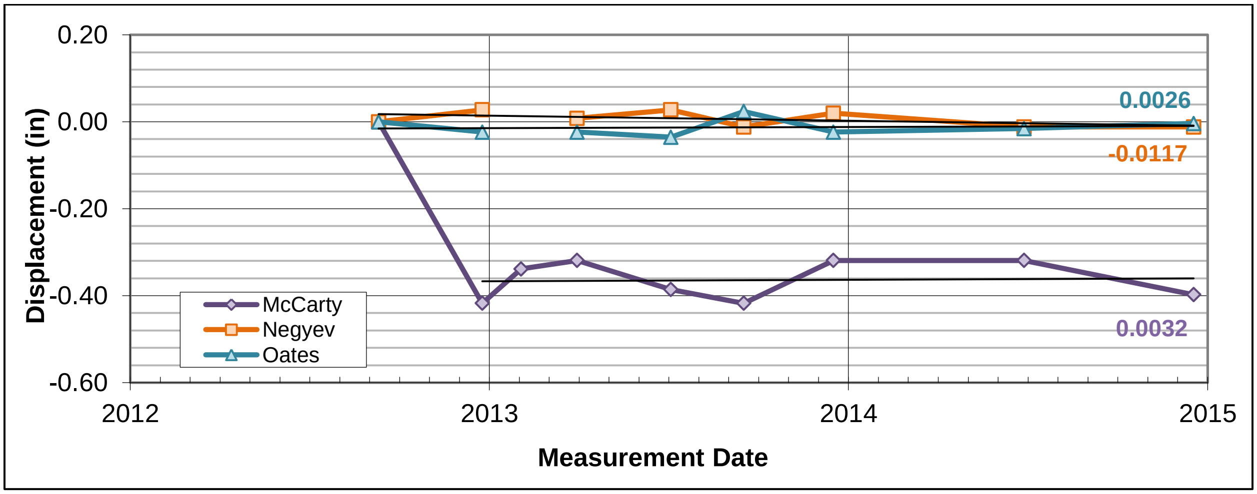

Figure 7. Fault Displacement over 1-Year Period for McCarty, Negyev and Oates

Finite element analysis (FEA) was conducted to determine the allowable fault displacement at Hockley, McCarty, Negyev, and Oates faults. FEA software ABAQUS v6.14 was used for the analysis. The soil properties at the four faults followed those used in the analysis for 2005 ORA and listed in Table 7. The pipe dimensions and buried depth used in the analysis are also provided in Table 8. At the McCarty, Negyev and Oates faults, there are two parallel 20-inch diameter lines sharing the same ROW. One line has a wall thickness of 0.25 inch and the other has a wall thickness of 0.375 inch. The 0.25-inch thick line which experienced larger stresses and limited the allowance of fault displacement was analyzed. The pipeline was buried about 10 feet below the ground surface at the McCarty Fault. The line immediately crossed State 610 Highway through HDD near the fault. The maximum depth of HDD is about 92.2 feet. The soil provided a higher restraint to the pipe with the increase of buried depth, which resulted in larger stresses. Therefore, a uniform 92.2 feet buried depth was used to analyze the allowable displacement at McCarty for conservative purposes. When the monitored displacement at the location is near the future allowable value, updated analyses should be conducted using more detailed profiles of the pipeline and buried depths. The pipe soil interaction elements in ABAQUS were used to simulate the soil force on the buried pipes.

In addition to the stress generated by fault movement, there are also stresses resulting from regular operational conditions in buried pipes that are known as operational stresses. These stresses can be determined following the equations in ASME B31.4. Operational stresses include the hoop stresses due to internal pressure and the longitudinal stresses due to internal pressure and thermal deformation. The operational hoop stress, $\sigma_{\mathrm{H\_o}}$, is calculated from Barlow's formula as

$$\sigma_{\mathrm{H\_o}} = \frac{p_{\mathrm{i}} D}{2t} \qquad (1)$$

where

p_i is the internal pressure, psig,

D is the outside diameter of the pipe, in, and

t is the wall thickness of the pipe, in.

The operational longitudinal stress, $\sigma_{\mathrm{L\_o}}$, which results from internal pressure and thermal expansion is given by

$$\sigma_{\mathrm{L\_o}} = \nu \cdot \sigma_{\mathrm{H\_o}} - \alpha E \Delta T \tag{2}$$

where

ν is the Poisson's ratio of steel, 0.3,

α is the coefficient of thermal expansion for steel, 6.5×10^{-6} in/in/°F,

ΔT is the difference between current operating pressure and installation temperature, °F, and

E is the elastic modulus of steel

The installation temperature was determined from the statistical climate data at the sites and the operating temperatures were determined from operation records. To be conservative, the MOP at each segment, as listed in Table 7, was used in calculating the operational stress.

The total stresses in the pipe were then derived by summing the stresses resulting from fault movements via FEA and operational stress via Equations (1) and (2). The combined biaxial stress, σ_{e}, can then be calculated from the total hoop stress, σ_{H}, and total longitudinal stress, σ_{L}, using the following equation:

$$\sigma_{\mathrm{e}} = \sqrt{\sigma_{\mathrm{L}}^2 + \sigma_{\mathrm{H}}^2 - \sigma_{\mathrm{L}}\sigma_{\mathrm{H}}} \tag{3}$$

ASME B31.4 updated the allowable longitudinal stress value in 2012. The allowed longitudinal stress of 54% of SMYS in ASME B31.4 before 2012 which was three quarters of the maximum hoop stress, which was 72% of SMYS. The new allowed longitudinal stress according to ASME B31.4 after 2012 increases to 90% of SMYS, which has been used for a long time in ASME B31.8 covering gas pipelines. The segment of Longhorn Pipeline at Hockley Fault was constructed in the 1950s. The quality of girth welds may not be as good as modern girth welds. The inspection requirement for girth welds after installation was not as strict as the current practice. On the other hand, there have been no failures in the Longhorn Pipeline related to girth welds during its operation history. This indicated that the quality of girth welds in the pipeline was at a reasonable level. As a result, we would recommend using 80% of SMYS (90% SMYS as allowed by B31.4 plus an additional safety factor of 10%, which has been typical of Longhorn practices in managing other threats on the existing 1950 pipeline) as the allowable longitudinal stress at Hockley Fault. The 90% of SMYS can be used for pipeline segments at McCarty, Negyev and Oates faults. These segments were installed in 2010. The allowable combined biaxial stress was still 90% of SMYS as shown in ASME B31.4.

Table 7. Soil Properties used in FEA for Fault Analysis

Property	Value	Units, notes
Density (ɣ)	125	lbs/ft^3
Cohesion (c)	1195.2	psf
Friction angle (φ)	23.6	degrees
Soil Poisson's ration	0.25	Unsaturated clay
Coating friction factor (f)	0.9, 0.6	Coal tar, FBE
Horizontal displacement at failure (Δ_t)	0.3	in.
Type of soil	Cohesive	

Table 8. Pipe Information Used for Stress Analysis at the Sites

Fault	Diameter (in)	Wall Thickness (in)	Buried Depth (feet)	MOP (psig)
Hockley	18	0.281	2.25	1012
McCarty	20	0.25	92.2*	936
Negyev	20	0.25	4	936
Oates	20	0.25	4	936

* This is the maximum buried depth in the adjacent segment installed through HDD. The buried depth just at the fault location is about 10 feet. The 92.2 feet was used in the analysis to provide conservatively estimated allowable displacement at the fault.

Figure 8 shows the total stress variations with the increase of displacement at Hockley Fault. The blue line represents the total longitudinal stress and the red line represents the combined biaxial stress. From the figure it can be seen that the longitudinal stress reaches 54% of SMYS around the 0.6 inch of fault displacement, which agrees with the 0.63 inch allowable displacement determined by 2015 analysis following the same longitudinal stress level. According to the discussion in the previous paragraph, ASME B31.4 revised this overly conservative limit for longitudinal stress. By increasing the allowable longitudinal stress to 80% of SMYS, the allowable displacement at the Hockley Fault is 1.25 inches. The combined biaxial stress reaches the limit of 90% of SMYS at 1.80 inches of fault displacement. Therefore, the allowable displacement at Hockley Fault is 1.25 inches controlled by longitudinal stress.

Figure 9 shows the total stress variations with the increase of displacement at the McCarty Fault. Unlike the Hockley Fault, the allowable displacement at the McCarty fault is controlled by combined biaxial stress. This is because the Hockley Fault is moving along a plane with a 67-degree dip angle. The other three faults were normal ones moving along vertical planes. The allowable displacement at the McCarty Fault is 0.95 inch as shown in Figure 9. It should be repeated that this value was determined with a very conservative buried depth. More detailed analysis should be conducted; the displacement at fault is close to the future allowable value.

Figure 10 shows the total stress variations with the increase of displacement at Negyev Fault and Oates Fault. The two faults are close to each other and the pipe dimensions and buried depth are also identical. Therefore, the same stress variation was estimated at the two faults. The allowable fault displacement at the two faults is 2.65 inches.

Table 9 summarizes the updated allowable displacement at Hockley Fault and the newly estimated allowable displacement at McCarty, Negyev and Oates faults. The years from no stress resulting from fault movement to failure was also provided based on the average fault movement rate as determined from Figure 6 and Figure 7.

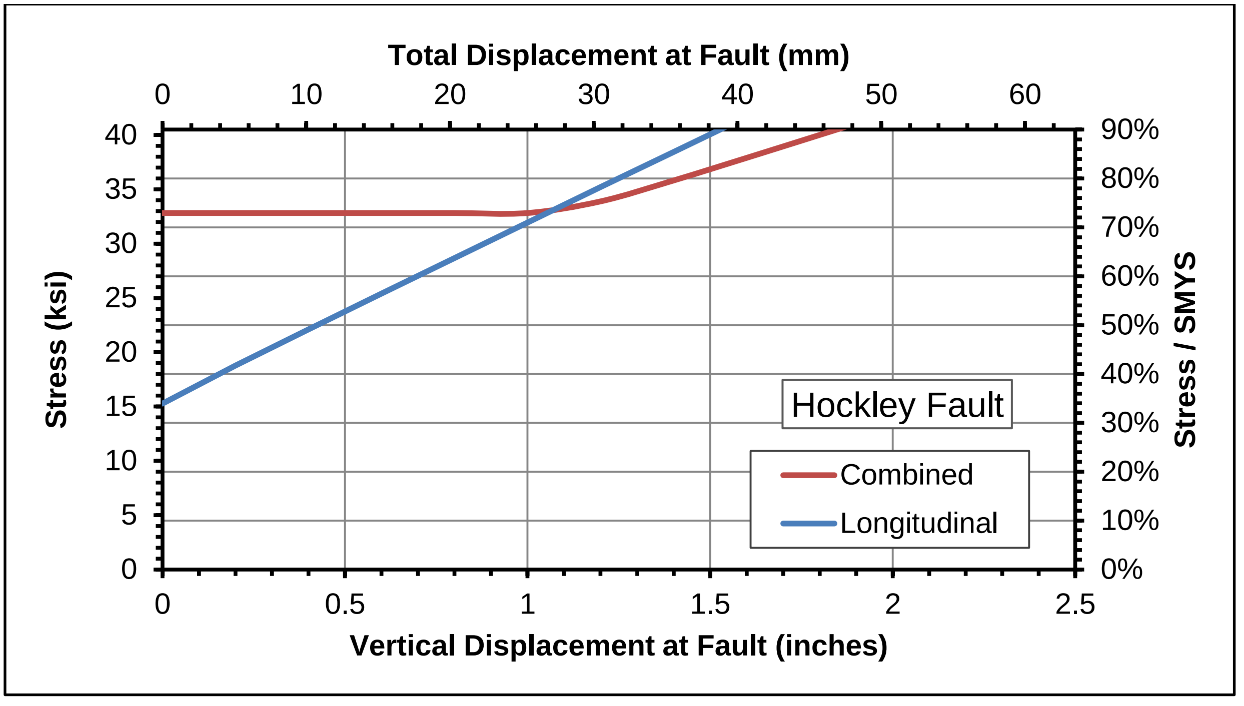

Figure 8. Longitudinal Stress and Combined Biaxial Stress in Pipes at Hockley Fault with Different Fault Displacement

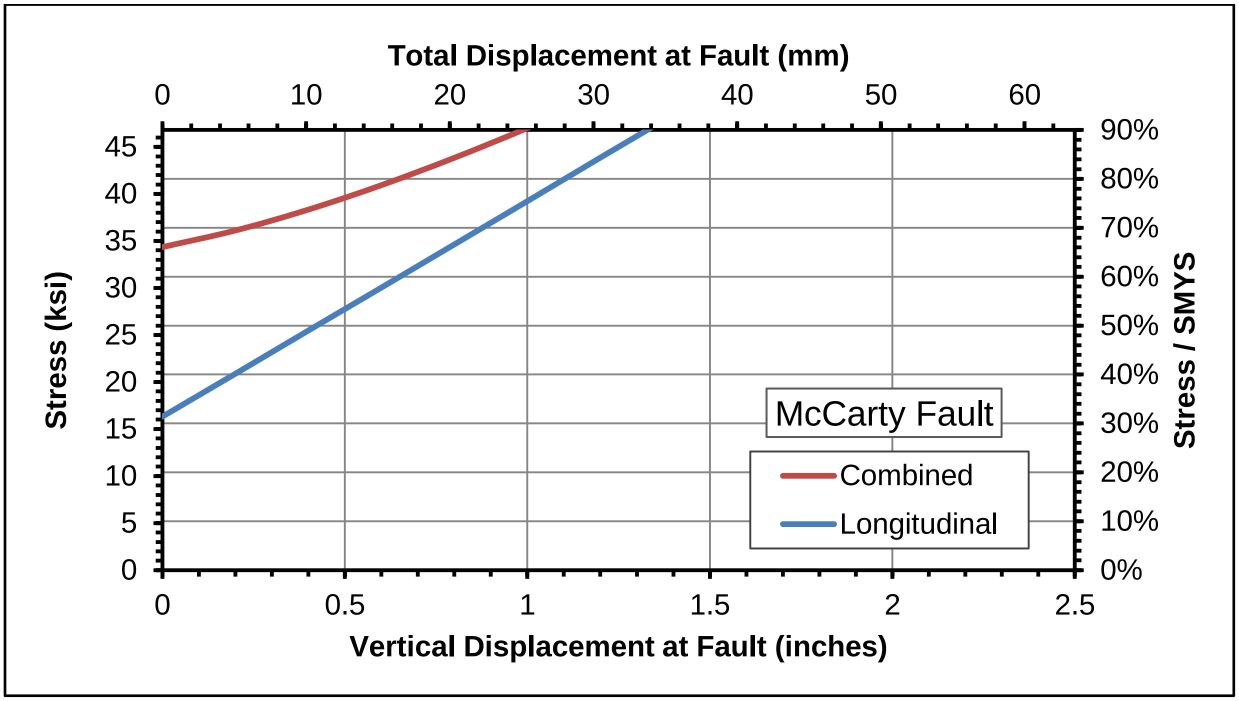

Figure 9. Longitudinal Stress and Combined Biaxial Stress in Pipes at McCarty Fault with Different Fault Displacement

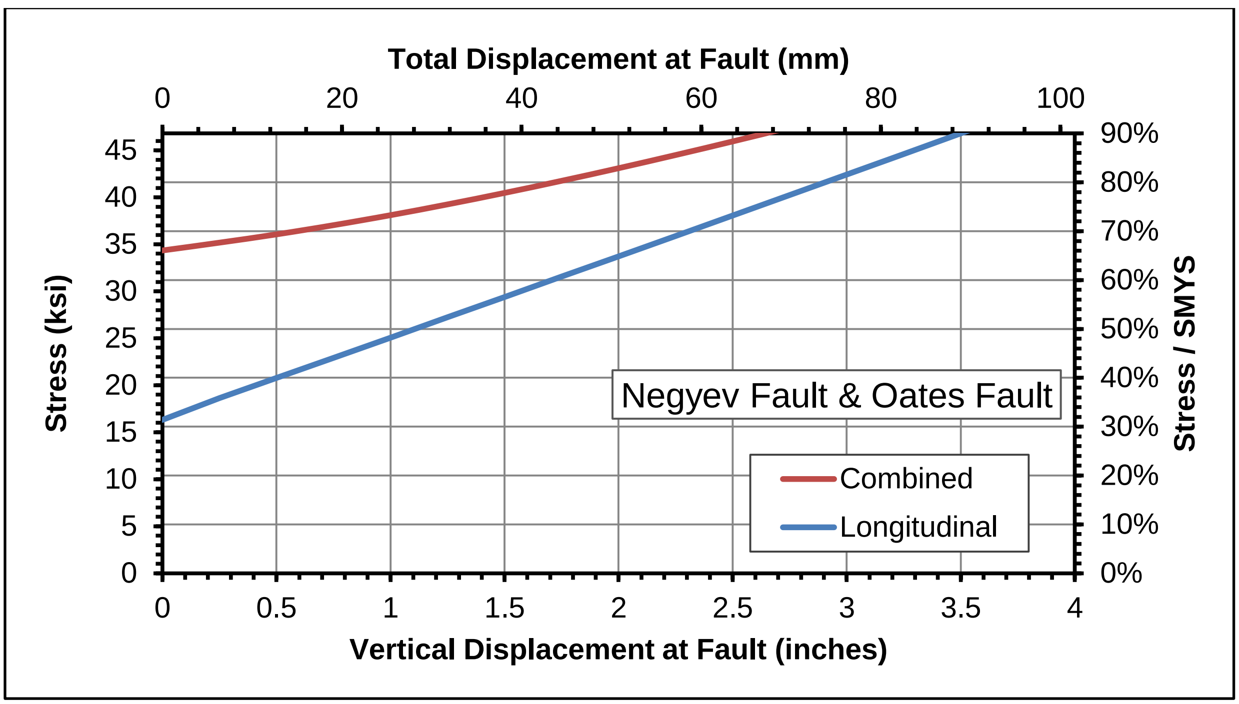

Figure 10. Longitudinal Stress and Combined Biaxial Stress in Pipes at Negyev Fault and Oates Fault with Different Fault Displacement

Table 9. Summary of Updated Allowable Fault Displacement at Hockley Fault and New Estimated Allowable Fault Displacement at McCarty, Negyev and Oates Faults

	Allowable Displacement (in)	Ave. Rate of Movement (in/yr)	Time to Reach Allowable Displacement (yrs)
Hockley	1.25	0.022	57
McCarty	0.95	0.0032*	> 297
Negyev	2.65	0.0017	> 226
Oates	2.65	0.0026	> 1000

* Ignoring the jump of ½ inch between the baseline point and the first reading point

Table 9 shows that the average moving rate at Hockley Fault is 0.022 inch/yr. It requires 57 years from a status of free to the stress due to fault movement to final failure of the pipe. The segment of the Longhorn Pipeline was installed in the 1950s. The life has just exceeded the 57-year limit. It should be noted that the calculated 57 years includes several conservative simplifications. For example, the actual fault has a fault zone width between several feet on the low end up to a hundred feet on the high end. In the finite element analysis (FEA), the fault movement was assumed to occur along a discontinuous plane without width, which conservatively overestimated the stress in pipe. Because no information about the season of installation of the segment is known, the worst temperature difference was assumed to determine the operational stress. Because of the conservative assumption used in the calculation and the lower stress limit selected for the longitudinal stress (80% instead of 90% in ASME B31.4), the risk of immediate failure is low. However, as the estimated 57 years is shorter than the life of the segment, it is recommended to use one of the following three practices to release the accumulated stress in the segment or conduct further investigation:

Option 1: Excavate and expose the pipeline segment including three joints at each side of the fault within five years. From the distribution of longitudinal stress resulting from fault movement shown in Figure 11, the recommended excavation length is enough to release the majority of accumulated longitudinal stress. The pipe will then be restored to a state free of stress caused by fault movement. The pipe can resist an additional 1.25 inches of fault movement before the next excavation. It is also recommended to examine the quality of girth welds in the exposed segment using this opportunity.

Option 2: If there is an existing inertial pigging record or an internal pigging is scheduled in near future, the level of current accumulated stresses in the pipe can be estimated. It will then be used to determine an accurate value of the additional fault displacement that can be accommodated by pipe before failure.

Option 3: If no inertial pigging record is available and no dig is scheduled in the near future, a literature review should be conducted to determine the fault movement history at the location since the installation of the pipeline.

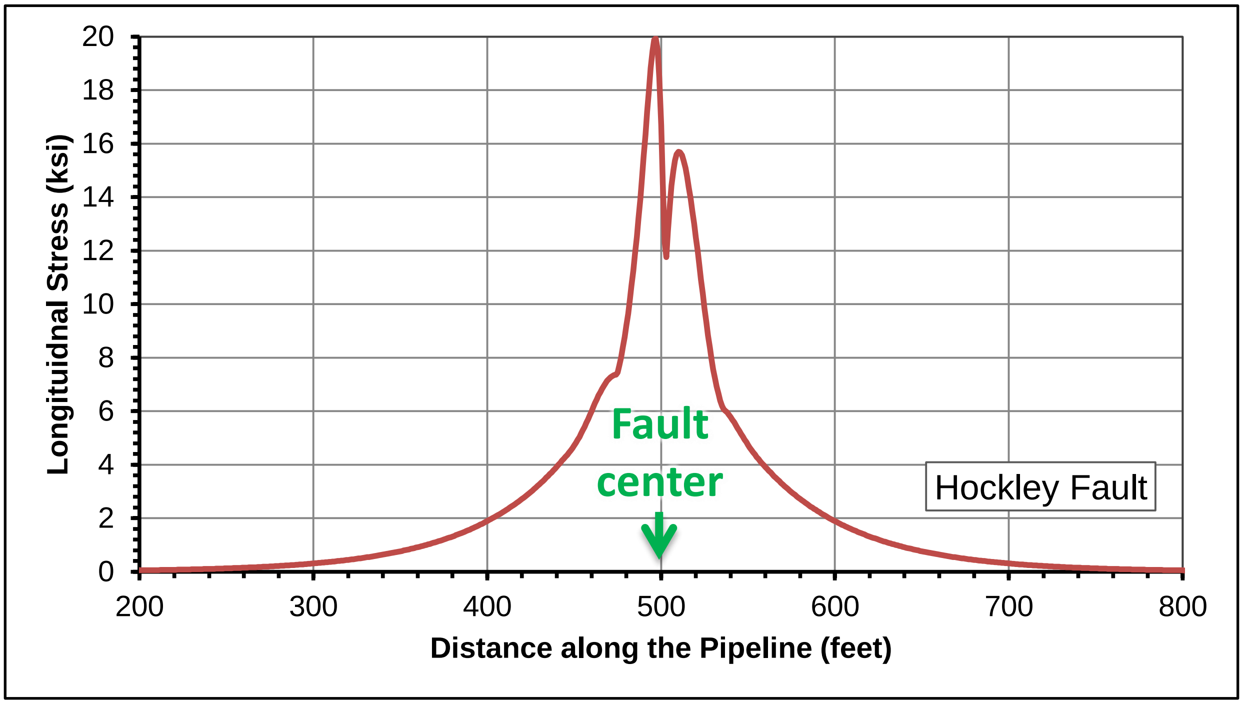

Figure 11. Distribution of the amplitude of longitudinal stress resulting from fault movement at Hockley Fault

Stream Crossings

There are many stream crossings on the Longhorn system, with all but two needing inspections once every five years according to studies generated by LMC 19(b) and covered in the ORA by section 6.3 of the ORAPM. The potential for failure was summarized in Appendix 9E of the original 2000 EA. The Colorado River (Figure 12) and its tributary Pin Oak Creek (Figure 13) were last surveyed in December 2014. The results show changes in the High Bank to the Toes on Pin Oak Creek of 6.0 feet and changes on the west Bank of Colorado River between Toe and High Bank of 2.0 feet. Both of them kept the same level as those in 2013 ORA.

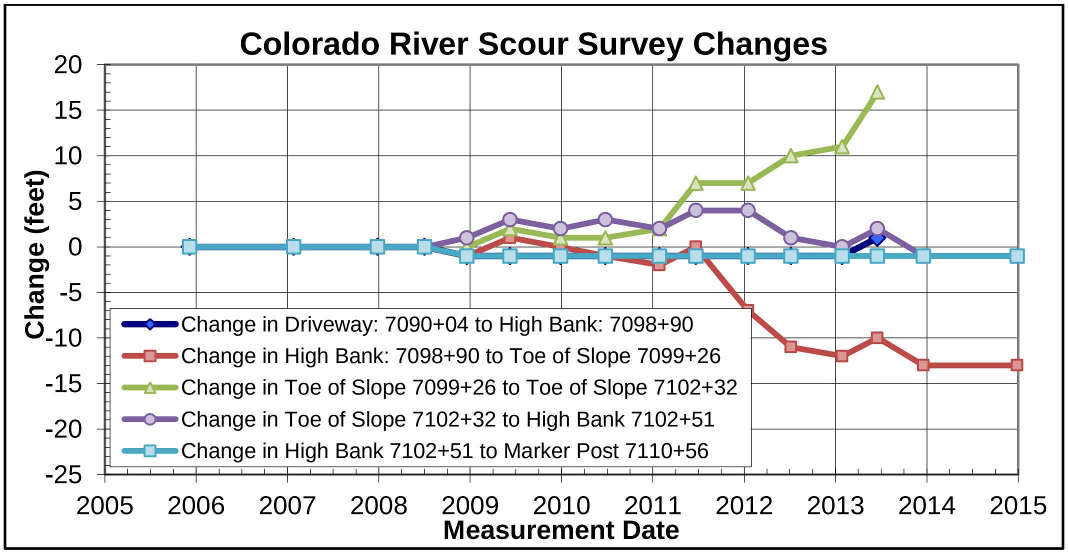

Figure 12. Changes in the Scour Survey of the Colorado River over 8 Years

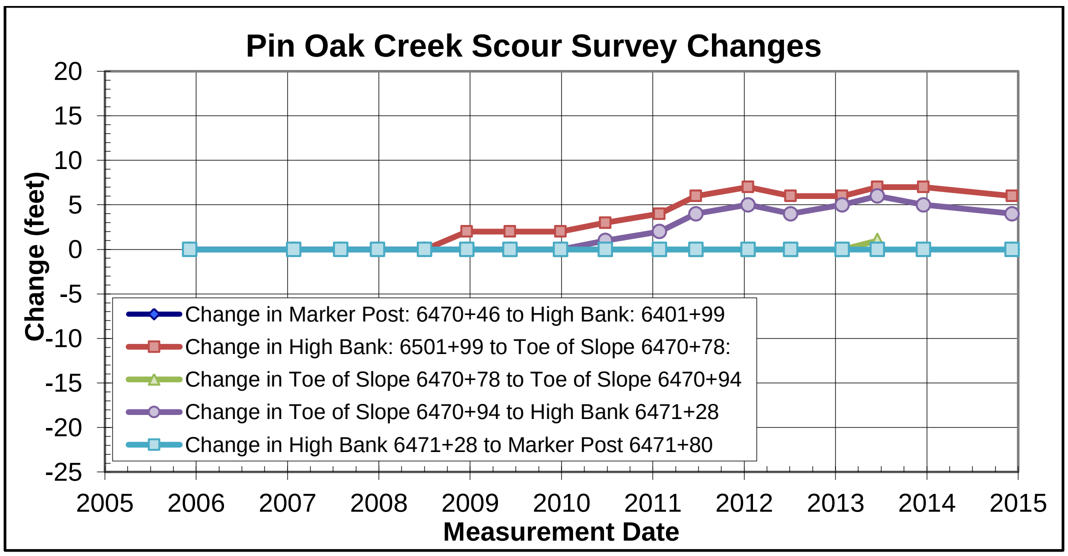

Figure 13. Changes in the Scour Survey of Pin Oak Creek over 8 Years

These changes in the distance from the High Bank to the Toes of Pin Oak Creek and the distance between the Toes and the distance from the West High Bank to the Toe of the Colorado River warrant a more accurate survey of the depth of burial of the pipeline in the river bed between the Toes of the two bodies of water to determine how much depth of cover loss is acceptable.

The Toe is apparently where the bank meets the water and can be affected by whether an upstream dam is open or closed. The measurements have also been affected by recent drought conditions. Such changes can also be an indication of erosion of cover over the pipeline. Based on the measurements of changes of 6.0 to 17 feet from 2013 ORA (no data provided in 2014), a better measurement is still recommended to determine if erosion is occurring and the pipeline is being exposed in the river bed. From discussions with Magellan it is understood a survey was conducted in 2015 and will be included in the 2015 ORA.

5.6. 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 1, Tier Classification
- Item 2, HCA pipeline sections
- Item 3, Date of pipeline installation
- Item 4, Hydrostatic test pressure achieved on last test
- Item 5, Current MOP
- Item 6, Current MASP
- Item 7, Outside pipe diameter
- Item 8, Pipe wall thickness
- Item 9, Pipe SMYS
- Item 17, Type of ILI tool data
- Item 18, Location and type of repair
- Item 19, Depth of Cover surveys
- Item 24, Corrosion control survey data
- Item 43, Maintenance Reports on line pipe anomalies
- Item 46, Facility Inspection and Compliance Audits
- Item 49, Action Item Tracking and Resolution
- 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 2014 TPD Annual Assessment we conclude:

- In 2014 there were zero third-party near misses.
- There were no One-Call violations in 2014.
- The 2014 TPD Annual Assessment shows a decrease of approximately 38 percent in the number of aerial patrol observations. One-Call frequency increased by 19 percent.
- There was an approximate 26.7 percent decline in unique aerial patrol observations, with a 25.7 percent drop in third-party activity or non-company aerial-patrol-observations.
- One-Call frequency increased approximately 19.3 percent and the number of tickets sent to Field Operations for clearing/locating increased by approximately 5.3 percent.

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

One new exposure was identified in 2014 by the ROW maintenance crew. The location was found on the landowner's pasture where heavy water runoff had cut a channel and crossed the pipeline. The line was backfilled and grass seeded. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the System Integrity Process (SIP) were repaired after additional erosion was found. Additionally, five road crossings were remediated with additional gravel cover, and one line lowering was completed on shallow pipe.

One-Call Violation Analysis

Out of 19,463 One-Calls in 2014, it appears that 15.4 percent required field locates and were potential ROW encroachments. Magellan 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). There were no One-Call violations during 2014.

Most One-Call tickets continue to occur in two counties. Harris County accounted for 12,856 (66 percent) of the One-Call tickets. Travis County accounted for 1,347 (7.0 percent) of the One-Call tickets. Thus, 76 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. El Paso has the next highest number with 992 tickets (5.0 percent).

Magellan should continue to ensure all relevant data is recorded on the incident data reports, including how the ROW near-misses were detected, to help improve the overall effectiveness of the third-party damage program.

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 2014 show that Magellan exceeded these requirements in terms of the total mileage patrolled.

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 no One-Call violations during 2014; therefore there is no requirement to conduct an additional ILI inspection with a geometry tool at this time.

No additional direct examinations are recommended at this time.

5.7. Stress-Corrosion Cracking

In the 64 years the Existing Pipeline has been in operation, 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.

5.8. Facilities Other than Line Pipe

During 2014 there were 11 internal incident data reports filed. Nine of the incidents occurred at facilities, two of which were DOT Reportable. One incident involved a release of approximately five barrels of diesel due to a combination of incorrect operation, faulty control logic, and inadequate operating procedures. The other involved in a release of approximately 20 gallons of refined product due to valves left open during pigging operations.

From the standpoint of facility data acquired for 2014, 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.

The Management of Change process requires that all changes be evaluated using an appropriate hazard analysis (HAZOP, what if, etc.) and that the change be risk assessed to ensure that the appropriate risk mitigation levels are maintained on the system.

ORA Review of LPSIP Facility Integrity Program Results

The LPSIP Mechanical Integrity Program focuses on maintaining the integrity of all equipment within the Longhorn system (e.g., station pumps, tanks, valves, and controls systems). The program includes the following activities:

- Identification and categorization of equipment and instrumentation
- Inspection and testing methods and procedures
- Testing acceptance criteria and documentation of test results
- Maintenance procedures and training of maintenance personnel
- Documentation of specific manufacturer's recommendations.

A Preventive Maintenance Program has been established under the Mechanical Integrity Program through the use of a software database system called Enviance/CMS. The software system establishes a unique inspection and maintenance schedule for major equipment items in the Longhorn system that can be adjusted on the basis of risk level.

An Action Item Tracking and Resolution Initiative (database) provides a method to track mechanical integrity recommendations.

Facility safety review inspections addressing items related to safety, security, and environmental compliance were completed for two of the pipeline facilities during 2014. No major problems were identified based on a review of the inspection forms extracted from the database.

Additionally, a Facility Risk Management Program is in place to manage the risks at above ground facilities.

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, however, it is recommended that Magellan investigate ways to improve training to reduce operational errors.

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 2014 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. This metric is compared to the previous 12-month periods. The goal would be 100 percent of the commitment. Magellan met this commitment in 2014.

- Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric is compared to previous Magellan performance. This metric is used to measure consistent effort by Magellan to protect the ROW and to prevent TPD. There is no "passing grade", because proper placement and maintenance of signs may lead to fewer signs replaced or repaired in future years, and this decline will not indicate any failing on the part of Magellan. On the other hand, tracking the replacement or repair of signs by pipeline segment may indicate third party vandalism or carelessness in certain segments of the system which could be used as a leading indicator that additional public education might be needed in that region of the pipeline route.

- Number of outreach or training meetings (listed with locations and dates) to educate and train the public and third parties about pipeline safety. This metric is used to gauge consistent effort by Magellan to educate the public regarding pipeline safety, with the goal of preventing TPD to the pipeline. There is no "passing grade", although a comparison of the results of this metric with sign placement, repair and replacement can be used to see if public education is being emphasized in the same geographic region where sign maintenance indicates problems. See Appendix B Item 58 for details.

- Number of calls (sorted by Tier I, Tier II or Tier III) through the One-Call system to mark or flag the Longhorn Pipeline. This is completed to measure the effectiveness of the One-Call system in preventing TPD. The measure is compared to previous years of Magellan records. Since this is a metric that is not subject to control by Magellan, there is no "passing grade". However, this metric can be compared to encroachments allowing an overall measurement of how efficiently the One-Call process is being used.

Table 10 provides a summary of the LPSIP Activity Measures from 2005 through 2014.

Table 10. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		203,081	197,234	188,884	187,931	181,308
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	536	460
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17
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
	Tier II	6,881	7,874	7,852	7,059	5,840
	Tier III	1,498	1,617	1,653	1,459	1,217

Measure		2010	2011	2012	2013	2014
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		180,045	188,564	188,772	179,107	176,884
No. of warning or ROW identification signs installed, replaced, or repaired		291	76	66	539	266
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		22	20	22	17	30
No. of calls through the One-Call system to mark or flag Longhorn's pipeline	Tier I	5,277	5,757	7,707	8,637	10,268
	Tier II	4,265	4,415	5,354	6,370	7,641
	Tier III	833	918	1,072	1,312	1,554

Deterioration Measures

Deterioration measures are metrics that evaluate maintenance trends to indicate when the integrity of the system could be foreseen as potentially declining despite preventive actions. A summary of the deterioration measures from 2005 through 2014 are presented in Table 11.

Although the ILI runs are not being performed on the same segments from year to year nor is the same inspection tool being used, there is still a discernible trend downward in anomalies found per mile. The number of immediate corrosion anomalies predicted based on the reassessments had dropped to zero when compared to the initial corrosion assessments. This indicates that the excavation program is effective at reducing and actually eliminating the number of significant corrosion anomalies.

POE evaluations show a significant decrease of over an order of magnitude between 2005-2007 when the first in-line inspections for corrosion were performed to 2009-2010 when the second set of in-line inspections for corrosion were performed. The 2014 POE evaluations are showing a similar trend to the 2009-2010 in-line inspections for corrosion.

Hydrostatic test leaks per mile have not been an indicator of performance because no hydrostatic re-inspection tests have been performed for pipeline integrity purposes.

Table 11. LPSIP Deterioration Measures

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

Measure		2010	2011	2012	2013	2014
Number of immediate ILI anomalies per mile pigged		0	0	0	0	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	0	0	0	0	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA*	NA*	NA**
Number of POE Evaluations per mile pigged		0.14	0.035	0.025	0.033	0.017

* Hydrostatic tests were performed for pipeline commissioning purposes.
**No hydrotests were performed during 2014.

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 in Table 12. Response times, volumes, and costs are for DOT reportable leaks.

Table 12. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009
Number of leaks (DOT reportable)		2	0	1	3	0
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA
	Tier II	NA	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA
Average product volume released per incident	Tier I	5.7 bbls	0	5.7 bbls	0.4 bbls	0
	Tier II	0	0	0	0	0
	Tier III	0	0	0	0	0
Total product vol. released in the 12-month period	Tier I	17 bbls	0	5.7 bbls	1.3 bbls	0
	Tier II	0	0	0	0	0

Measure		2005	2006	2007	2008	2009
	Tier III	0	0	0	0	0
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	0	1	3	3
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0
Number of near-misses to the pipeline by third parties		7	1	7	5	6
Number of service interruptions		115	165	155	74	16*

* Service interruptions counting changed between 2008 and 2009. In 2005-2008 service interruptions included all system stoppages including those related to business reasons, such as lack of throughput. In 2009-2010 service interruptions only includes stoppages related to safety.

Measure		2010	2011	2012	2013	2014
Number of leaks (DOT reportable)		1	2	0	2	2
Average response time in hours for a product release.	Tier I	Immed.	Immed.	NA	Immed.	Immed.
	Tier II	NA	NA	NA	Immed.	Immed.
	Tier III	NA	NA	NA	Immed.	Immed.
Average product volume released per incident	Tier I	0.4 bbls	1.2 bbls	NA	0.47 bbl	2.74 bbl
	Tier II	0	0	NA	0	0
	Tier III	0	0	NA	4 bbls	0
Total product vol. released in the 12-month period	Tier I	0.4 bbls	2.5 bbls	NA	0.47 bbl	5.48 bbl
	Tier II	0	0	NA	0	0
	Tier III	0	0	NA	4 bbls	0
Cleanup cost totals per year		< $50k	< $50k	NA	> $100k	<$25k
Cleanup cost per incident		< $50k	< $25k	NA	< $25 < $50k > $100k	< $25k
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper One-Call		1	1	2	2	0
Number of known physical hits (contacts with pipeline) by third-party activities		0	2	0	0	0
Number of near-misses to the pipeline by third parties		2	4	3	2	0
Number of service interruptions		17	9	8	15	15

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/H_2S 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 preferential 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 detection of 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 interval procedures 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 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 these technologies to maximize the effectiveness of activities that are required by the ORAPM or recommended by the ORA Contractor.

Table 13 is a compilation of the tools run to date, and required reassessments as specified by the ORAPM. Reassessment requirements for pressure-cycle-fatigue crack growth reassessment intervals were based on the analysis performed in Section 5.1 of this report. Reassessment requirements for corrosion, laminations/hydrogen blisters, and third party damage are based on the most recent inspection date; corrosion and lamination/hydrogen blister inspections are required to be run every five years while third party damage inspections are required every three years. Earth movement, the fifth component for threat integration, is not included in Table 13 because it is currently addressed using surface surveys rather than ILI technology.

Table 13. Existing ILI Runs and Planned Future Inspections

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Threats Addressed: Pressure-Cycle Induced Fatigue	Threats Addressed: Laminations and Hydrogen Blisters	Threats Addressed: Third-Party Damage
Speed Junction to East Houston MP 10.83 to MP 2.35	Deformation	2-Oct-14				X
	SMFL	2-Oct-14	X			X
	Next Required Assessment		***2-Oct-19***	*Not susceptible*	*Not susceptible*	***2-Oct-19***
East Houston to Satsuma MP 0 to MP 34.1	Deformation	10-Jun-04				X
	MFL [1]	28-Oct-04	X			X
	MFL [2]	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
	Deformation	7-June-12				X
	Deformation	22-June-13				X
	SMFL	1-Oct-14	X			X
	Deformation	1-Oct-14				X
	Next Required Assessment		***1-Oct-19***	***2032***	***	***1-Oct-17*** [3]
Satsuma to Warda MP 34.1 to MP 112.9	MFL/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
	Deformation	7-Jun-12				X
	MFL [4]	18-Dec-14	X			X
	Deformation	18-Dec-14				X
	Next Required Assessment		***18-Dec-19***	***2020***	***	***18-Dec-17***
Warda to Cedar Valley MP 112.9 to MP 181.6	MFL/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
	Deformation	9-Jun-12				X
	Next Required Assessment		***24-Jan-15***	***2018***	***	***9-Jun-15***

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Pressure-cycle Induced Fatigue	Laminations and Hydrogen Blisters	Third-Party Damage
Cedar Valley to Eckert MP 181.6 to MP 227.9	MFL/Deformation	15-Feb-07	X			X
	TFI	22-Mar-07	‡	X		
	Deformation	25-Jan-10				X
	UT	20-Feb-10	X		X	X
	Deformation	15-Jun-12				X
	Next Required Assessment		***20-Feb-15***	***2022***	*****	***15-Jun-15***
Eckert to Ft McKavett MP 227.9 to MP 321.9	MFL/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
	Deformation	17-Jun-12				X
	Next Required Assessment		***25-Jun-15***	***2021***	*****	***17-Jun-15***
Ft.McKavett to Crane MP 321.9 to MP 457.5	MFL/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
	Deformation	1-Jul-12				X
	Next Required Assessment		***8-Jul-15***	***2226***	*****	***1-Jul-15***
Crane to Cottonwood MP 457.5 to MP 576.3	Deformation	2-May-07				X
	MFL/Deformation	21-Nov-08	X			X
	MFL/Deformation	19-Nov-13	X			X
	Next Required Assessment		***19-Nov-18***	***2226***	***not susceptible***	***21-Nov-18***
Cottonwood to El Paso MP 576.3 to MP 694.4	Deformation	2-May-07				X
	MFL/Deformation	27-Mar-08	X			X
	MFL/Deformation	19-May-12	X			X
	Next Required Assessment		***19-May-17***	***not susceptible***	***not susceptible***	***19-May-17***
Crane to Odessa	MFL/Deformation	4-Nov-06	X			X
	MFL/Deformation	7-Mar-07	X			X
	MFL/Deformation	28-Jun-11	X			X
	Next Required Assessment		***28-Jun-16***	***not susceptible***	***not susceptible***	***28-Jun-16***

	Tool	Date of Tool Run	Threats Addressed: Corrosion	Threats Addressed: Pressure-cycle Induced Fatigue	Threats Addressed: Laminations and Hydrogen Blisters	Threats Addressed: Third-Party Damage
El Paso to Chevron 8" MP 0.0 to 9.4	MFL/Deformation	6-Mar-07	X			X
	MFL/Deformation	23-Feb-12	X			X
	Next Required Assessment		***23-Feb-17***	***not susceptible***	***not susceptible***	***23-Feb-17***
Kinder Morgan 8" Flush Line	MFL/Deformation	6-Mar-07	X			X
	MFL/Deformation	21-Feb-12	X			X
	Next Required Assessment		***21-Feb-17***	***not susceptible***	***not susceptible***	***21-Feb-17***
El Paso to Kinder Morgan 12" MP 0.0 to 9.4	MFL/Deformation	7-Mar-07	X			X
	MFL/Deformation	22-Feb-12	X			X
	Next Required Assessment		***22-Feb-17***	***not susceptible***	***not susceptible***	***22-Feb-17***

1 The MFL tool run in Oct-04 was not a complete run.
2 The MFL tool run in Dec-05 was used to complete the Oct-04 MFL run.
3 Per LMC 12A this portion should be inspected for third party damage every 3 years; however, since an MFL tool run is scheduled to be conducted for corrosion and laminations and hydrogen blisters in September 2014, it will also be inspected for third party damage at that time.
‡ 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.
4 Satsuma to Warda was divided into two segments: Buckhorn to Satsuma and Warda to Buckhorn. Buckhorn to Satsuma was inspected on 18-Dec-14 and Warda to Buckhorn was inspected on 16-Dec-14.
*Per Longhorn EA section 9.3.2.3 Electronic Geometry Pig (EGP) assessments are required every 3 years in accordance with the LMP. Deformations identified from these assessments will be correlated to the existing laminations found from the UT assessments.

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 Junction. 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 has been 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 required five-year interval 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. An MFL-Deformation combination tool run was completed on March 7, 2007 and re-run June 28, 2011 with three digs being completed in 2012. The re-inspection 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

Other Pipe Replacements

A number of pipe replacements were completed in 2013 during the pipeline flow reversal on the original pipe segments. A number of potential integrity threats were removed from the pipeline during the reversal process. These include stopple fittings, weld plus end fittings, split tee fittings, non-pressure containing sleeves, a patch, deformation anomalies, and corrosion anomalies. There were no pipe replacements during 2014.

8. RECOMMENDED IMPROVEMENTS TO THE ORA PROCESS

Table 14. Summary of 2014 Recommendations

Topic	Recommendation	ORA Ref Page
Hydrogen Blistering	With the conversion of the pipeline back to crude oil service and the reintroduction of hydrogen sulfide, monitoring of the lamination anomalies for the possibility of blister growth with ILI tools is recommended per the EA of the proposed Longhorn Pipeline Reversal Section 6.2.1.2. These inspections should be coordinated with ILI runs for corrosion, deformation, and mechanical damage.	12
Aseismic faults	We continue to recommended that 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.	12
Stream Monitoring	Recorded changes in the distance from the High Bank to the Toes of Pin Oak Creek and the Colorado River warrant a survey of depth of burial of the pipeline in the stream beds between the toes of the banks of these two bodies of water.	13
Reliability Based Design Analysis (RBDA)	Longhorn should consider using a reliability-based design analysis (RBDA) to calculate the probability that a corrosion feature may fail by either perforation leak or plastic collapse, often simply referred to as leak or rupture.	15

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.

Intentionally blank

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
Appendix Item 3	Longhorn will replace approximately six miles of Existing Pipeline in the Pedernales River watershed that is characterized as having a time of travel for a spill from Lake Travis of eight hours or less.	Segment 5 crossing the Pedernales River will be completed prior to the date of pipeline startup. Segments 1 through 4 will be replaced as determined by the System Integrity Plan and Operational Reliability Assessment, but in any case no later than seven years from the startup date.	Outside force damage

Intentionally blank

APPENDIX B - NEW DATA USED IN THIS ANALYSIS

This 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)

Kiefner received a listing of pipe replacements and related equipment that were installed during 2013. This listing is provided in Appendix C. There were no new facilities or pipe replacements during 2014.

Pump Stations (Item 15)

Phase 2 of the Longhorn Reversal Project consisted of increasing the flow rate on the pipeline from Crane, TX to Houston, TX from 134,000 bpd to 225,000 bpd. Phase 2 involved changing out the pumps at the three Phase 1 stations (Crane, Kimble County, and Cedar Valley), upgrading and reactivating the Satsuma Station, and adding an additional eight intermediate pump stations (Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn). This was completed in 2013.

The only change in 2014 was an increase in flowrate from 225,000 bpd to 292,000 bpd from East Houston to Crane and an increase to 2,100 bph on the Western refinery connection at El Paso

The following is a current list of the Longhorn pump stations, milepost numbers, and tier levels.

Table B-1. Pump Stations

Milepost	Facility Name	Tier
457.54	CRANE	2
416.64	TEXON	2
373.60	BARNHART	2
344.28	CARTMAN	2
321.95	FT MCKAVETT	2
295.19	KIMBLE COUNTY	2
260.17	JAMES RIVER	1
227.94	ECKERT	1
181.60	CEDAR VALLEY	2
141.78	BASTROP	1
112.90	WARDA	1
67.95	BUCKHORN	1
34.09	SATSUMA	3
2.36	EAST HOUSTON	2

Kiefner received process flow diagrams, a listing of the stations, and the Phase 2 Project Plan, Pump Station Materials and Construction during 2014. No new pump stations were installed during 2014.

Tier Classifications and HCAs (Items 1 and 2)

Kiefner received a listing of tier classifications and HCAs for the Longhorn System.

Charpy V-Notch Impact Energy Data (Item 14)

Charpy data from 16 locations along the Longhorn Pipeline were tested in 2013 as part of the validation of the Positive Material Identification Field Services process developed by T. D. Williamson. The results are listed below:

Table B-2. Charpy V-Notch Impact Energy Data

Pipe Sample	Sample Milepost	Pipe Grade	Measured Upper Shelf Energy (ft-lbs)	Full Size Equivalent Upper Shelf Energy (ft-lbs)	Transition Temperature (deg F at 85% shear)
3	31.86	B	18	26.9	137.9
30	33.43	B	33	49	72.3
37	64.06	X-42	116	116.0	143
6	103.72	X-45	13	26.0	62
13	156.59	X-45	16	32.0	107.3
16	210.57	X-45	18	26.9	103.7
18	227.20	X-45	25.5	38.0	144
20	280.50	X-45	24	48.0	94.6
23	316.57	X-45	16.5	25.0	74
32	43.15	X-45	16	32.0	109.4
33	134.66	X-45	29	38.7	147
34	163.20	X-45	21	31.3	140.3
35	341.65	X-45	18	36.0	93.5
26	419.14	X-52	15	30.0	97
31	35.00	X-52	49	98.0	19.8
36	436.12	X-52	20.5	41.0	109.3

Mill Inspection Defect Detection Threshold (Item 13)

Magellan reviewed the documentation for each pipe segment covered by the Longhorn Mitigation Plan (LMP) to establish whether a mill test report (MTR) exists to confirm that the pipe meets the code or industry standard such as API 5L, 5LX, or 5LS. The results were summarized and submitted to PHMSA on January 14, 2013.

4.2. Operating Pressure Data

For Items 21, 22, and 23, Kiefner has received pressure and flow data for Galena Park, East Houston, Satsuma, Cedar Valley, Kimble County, Crane, and El Paso Pump Station since September 17, 2004. From November 1, 2013 to December 31, 2014 pressure and flow data has also been received for Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn Pump Stations. The data is collected in 1-minute intervals and sent on a monthly basis.

4.3. ILI Inspection and Anomaly Investigation Reports

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

Data was received from a total of 24 maintenance reports for evaluations completed in 2014. Table B-3a shows the breakdown of where the maintenance reports occurred (segment and tier) while Table B-3b shows a breakdown of what reported anomalies were excavated per segment.

Table B-3a. Remediations per Maintenance Reports Completed in 2014

Line Segment	18" El Paso to Cottonwood	18″ Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Warda
ILI Date	5/19/2012	11/19/2013	8/5/2010	6/25/2010	2/20/2010	1/24/2010
Maintenance Report	Yes	Yes	Yes	Yes	Yes	Yes
Tier 1	1	1	0	0	2	0
Tier 2	0	1	0	0	0	0
Tier 3	0	0	0	0	0	0
Total Digs	1	2	0	0	2	0
HCA	0	0	0	0	0	0
Non-HCA	1	2	0	0	2	0

Line Segment	18" Warda to Satsuma	20" Satsuma to East Houston	20″ East Houston to Speed Jct	8″ El Paso to Chevron	12″ El Paso to Kinder Morgan	8″ Kinder Morgan to Flush Line
ILI Date	12/18/2014	10/1/2014	10/2/2014			
Maintenance Report	Yes	No	No	No	No	No
Tier 1	0	0	0	0	0	0
Tier 2	0	0	0	0	0	0
Tier 3	0	0	0	0	0	0
Total Digs	0	0	0	0	0	0
HCA	0	0	0	0	0	0
Non-HCA	0	0	0	0	0	0

Table B-3b. Reported Anomalies Excavated per the 2014 Maintenance Reports

ILI Anomaly Called	Number of Anomalies Addressed	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Warda	18" Warda to Satsuma	20" Satsuma to East Houston	20" East Houston to Speed Jct	8" El Paso to Chevron	12" El Paso to Kinder Morgan	8" Kinder Morgan to Flush Line
Ext Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0	0
Int Metal Loss	3	1	2	0	0	0	0	0	0	0	0	0	0
Mill Anomaly w/Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent Associated w/Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Sloping	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Variable Depth	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Bulging	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Bulging Intermittent	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction - Sharp - Dent on Weld	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction L<1.5D	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction L>1.5D	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction on Weld	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction w/associated metal loss	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction affecting pipe curvature at seam weld	0	0	0	0	0	0	0	0	0	0	0	0	0
Girth Weld Anomaly	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard Spot Investigation	2	0	0	0	0	2	0	0	0	0	0	0	0
Expansion	0	0	0	0	0	0	0	0	0	0	0	0	0
Buckle	0	0	0	0	0	0	0	0	0	0	0	0	0
Geometric Anomaly Associated w/Metal Loss	0	0	0	0	0	0	0	0	0	0	0	0	0

ILI Anomaly Called	Number of Anomalies Addressed	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Ft McKavett	18" Ft McKavett to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Warda	18" Warda to Satsuma	20" Satsuma to East Houston	20" East Houston to Speed Jct	8" El Paso to Chevron	12" El Paso to Kinder Morgan	8" Kinder Morgan to Flush Line
Area Of Bulge	0	0	0	0	0	0	0	0	0	0	0	0	0
Surface Irregularity	0	0	0	0	0	0	0	0	0	0	0	0	0
Weld Irregularity	0	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Associated With Brc Dent	0	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Associated With Lamination	0	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Crosses Girth Weld	0	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Crosses Long Seam	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	5	1	2	0	0	2	0	0	0	0	0	0	0

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

See above. Please note that J-1 is no longer in service.

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

Based on the 2014 excavation reports and previous ILI reports, no confirmed blisters have been found on the original Longhorn segments. One lamination was excavated and repaired in 2014 on the Ft. McKavett to Eckert segment.

4.4. Hydrostatic Testing Reports

No hydrostatic tests were conducted during 2014.

Hydrostatic Leaks and Ruptures (Item 75)

No hydrostatic tests of the Existing Pipe were performed during 2014.

4.5. Corrosion Management Surveys and Reports

Corrosion Control Survey Data (Item 24)

Corrosion Control Survey data was received from Magellan covering 2013. The next survey is to be completed in 2018.

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

See section 4.3 above.

External

Corrosion Growth Rate Data (Item 36)

The 2006 MFL data and 2014 MFL data were correlated to determine external corrosion growth rates for anomalies detected by each tool. The observed corrosion growth rate average for the 18-inch Satsuma to Warda segment was 6.2 mils per year (mpy) and for the 20-inch Satsuma to East Houston segment was 3.7 mpy. These corrosion growth rates are consistent with the 5.0 mpy rate found in an external corrosion growth study performed in 2011 by Quest Integrity Group.

Internal Corrosion Coupon Results (Item 37)

Internal corrosion coupon reports were reviewed at 13 locations for the 2014 annual report. The internal corrosion coupons are evaluated three times per year with a not to exceed of 4.5 months between surveys. The 13 locations sampled with coupons were: the 8-inch Odessa lateral at Crane; the 8-inch Plains lateral at El Paso; the 12-inch Centurion Delivery at Crane;

the 16-inch Advantage Delivery at Crane; one each at the 16-inch Plains WTI & WTS Deliveries at Crane; one at each of the following 18-inch stations: Cartman, Cedar Valley, and Satsuma; the 18-inch mainline at El Paso; one each on the 20-inch line at East Houston ML and Speed Junction Manifold; and the 24-inch Tank Manifold at Crane. Little to no corrosion was observed on the internal corrosion coupons. Table B-4 shows the results from the internal corrosion coupons.

Table B-4. Internal Corrosion Coupon Results

Pipe OD (in)	Location	Line Designation	Coupon Number	Inserted	Removed	Exposure (days)	Rate (MPY)	Under Holder Attack	Comments
Crude Line									
12	Crane	Centurion – Delivery to Crane	T0217	12/19/13	4/24/14	126	0.00	None	
12	Crane	Centurion – Delivery to Crane	T0224	4/24/14	9/11/14	140	0.00	None	
12	Crane	Centurion – Delivery to Crane	S9474	9/11/14	12/29/14	109	0.00	None	
16	Crane	Advantage – Delivery to Crane	T0214	12/23/13	4/24/14	122	-0.03	None	
16	Crane	Advantage – Delivery to Crane	T0219	4/24/14	9/11/14	140	0.00	None	
16	Crane	Advantage – Delivery to Crane	S9481	9/11/14	12/29/14	109	0.00	None	
16	Crane	Plains WTI – Delivery to Crane	T0212	12/23/13	4/24/14	122	0.00	None	
16	Crane	Plains WTI – Delivery to Crane	T0221	4/24/14	9/11/14	140	0.00	None	
16	Crane	Plains WTI – Delivery to Crane	S9489	9/11/14	12/29/14	109	0.00	None	
16	Crane	Plains WTS – Delivery to Crane	T0215	12/23/13	4/24/14	122	0.00	None	
16	Crane	Plains WTS – Delivery to Crane	T0223	4/24/14	9/11/14	140	0.00	None	
16	Crane	Plains WTS – Delivery to Crane	S9494	9/11/14	12/29/14	109	0.00	None	
18	Cartman	Cartman Station ML (6645)	E4745	12/16/13	5/12/14	147	0.00	None	
18	Cartman	Cartman Station ML (6645)	F4884	5/12/14	9/10/14	121	0.00	None	
18	Cartman	Cartman Station ML (6645)	E4843	9/10/14	12/19/14	100	0.00	None	
18	Cedar Valley	Cedar Valley Station ML (6645)	E4746	1/2/14	5/2/14	120	0.00	None	
18	Cedar Valley	Cedar Valley Station ML (6645)	F4885	5/2/14	No Data – Coupon lost in mail				
18	Cedar Valley	Cedar Valley Station ML (6645)	E4964	9/22/14	1/2/15	102	0.00	None	
18	Satsuma	Satsuma Station ML (6645)	E4846	9/19/13	1/3/14	106	0.00	None	
18	Satsuma	Satsuma Station ML (6645)	E4749	1/3/14	5/5/14	122	0.00	None	
18	Satsuma	Satsuma Station ML (6645)	F4886	5/5/14	9/3/14	121	No Data – Coupon Broke in system		
18	Satsuma	Satsuma Station ML (6645)	E4923	9/8/14	1/2/15	116	0.00	None	
20	E. Houston	East Houston ML (6645)	T0213	1/2/14	4/28/14	116	0.00	None	
20	E. Houston	East Houston ML (6645)	T0222	4/28/14	9/3/14	128	0.00	None	
20	E. Houston	East Houston ML (6645)	S9475	9/3/14	12/31/14	119	0.00	None	
20	Speed Jct.	Speed Jct. Manifold from E. Houston (6643)	E4744	12/31/13	5/1/14	121	0.00	None	
20	Speed Jct.	Speed Jct. Manifold from E. Houston (6643)	F4883	5/1/14	9/1/14	123	0.00	None	
20	Speed Jct.	Speed Jct. Manifold from E. Houston (6643)	E4928	9/1/14	12/30/14	120	0.00	None	
24	Crane	Tank Manifold at Crane	E4849	12/23/13	4/24/14	122	0.00	None	
24	Crane	Tank Manifold at Crane	F4882	4/24/14	9/11/14	140	0.00	None	
24	Crane	Tank Manifold at Crane	E4899	9/11/14	12/29/14	109	0.00	None	
Refined Line									
8	Crane	Odessa to Crane 8” (6648)	T018	12/23/13	4/24/14	122	0.01	None	
8	Crane	Odessa to Crane 8” (6648)	T0220	4/24/14	9/11/14	140	0.00	None	
8	Crane	Odessa to Crane 8” (6648)	S9483	9/11/14	12/19/14	109	0.00	None	

Pipe OD (in)	Location	Line Designation	Coupon Number	Inserted	Removed	Exposure (days)	Rate (MPY)	Under Holder Attack	Comments
8	El Paso	Plains 8" (6650) - Outbound	AX0095	12/31/13	5/1/14	121	0.00	None	
8	El Paso	Plains 8" (6650) – Outbound	AX0097	5/1/14	9/3/14	125	0.00	None	
8	El Paso	Plains 8" (6650) - Outbound	AX0100	9/3/14	12/30/14	118	0.00	None	
18	El Paso	18" Mainline (6645)	AX0094	12/31/13	5/1/14	121	0.00	None	
18	El Paso	18" Mainline (6645)	AX0096	5/1/14	9/3/14	125	0.00	None	
18	El Paso	18" Mainline (6645)	AX0099	9/3/14	12/30/14	118	0.00	None	

Line Pipe Anomalies/Repairs (Item 43)

See section 4.3 above. A number of potential integrity threats were addressed in 2014. These included investigations (anomaly, POE, and 3rd party), scour study, valve and pipe replacement, wash out repair, adding cover on top of pipeline, line lowering, and addressing exposed pipe. Table B-5 lists the maintenance performed based on the 24 maintenance reports.

Table B-5. Maintenance Report Items

Maintenance Report Items	Number
A-sleeve cut out	0
AC mitigation	0
Anomaly Investigation	3
POE Investigation	2
3rd Party Investigation	4
Scour Study	1
Remove Re-circulation Valve and Replace Piping	1
Repair Washed Out Culvert	1
Add Cover on top of Pipeline	6
Line Lowering	1
B-sleeve recoat	0
Corrosion cut out	0
Dent cut out	0
Address exposed pipe	5
Patch cut out	0
PMIFS	0
Split tee cut out	0
Stopple cut out	0
Install test station	0
Trap upgrade	0
Valve installation	0
Weld plus end cut out	0
Weld misalignment cut out	0
Material grade testing cut out	0

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)

Semi-annual fault displacement monitoring reports were received covering the fault crossings in 2014.

Periodic Fault Benchmark Elevation Data (Item 31)

Semi-Annual Fault Displacement Monitoring was performed June 27, 2014 and December 17, 2014 which covers semi-annual fault measurements at the seven fault monitoring sites since inception in mid-2004 through December 2014.

The 2014 operating temperature record and line fill for the segments from East Houston to Speed JCT were used in the allowable fault displacement analysis.

Pipeline Maintenance Reports for Stream Crossings (no item number)

Scour reports were received for the two stream crossings, the Colorado River, its tributary Pin Oak Creek which were last monitored in December 2014. The reports this year are missing distances for the stream crossing from the toe of the slopes from each side of the stream. This is the first year in many years this data is missing. In addition the data for Pin Oak Creek was reported on a form that stated it was for the Colorado River and the data for the Colorado River was reported on a form that stated it was for Pin Oak Creek.

The 2012 and 2013 ORAs recommended these two crossings be surveyed for exposure in the stream bed for which data is expected in 2015.

Flood Monitoring (no item number)

Flood monitoring spreadsheets were received for Colorado River, Pin Oak Creek, and the Pedernales River. No records exceed the flood stage at any rivers in 2014.

4.7. Maintenance and Inspection Reports

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

One new exposure was identified in 2014 by the ROW maintenance crew. The location was found on the landowner's pasture where heavy water runoff had cut a channel and crossed the pipeline. The line was backfilled and grass seeded. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the SIP were repaired after additional erosion was found. Additionally, five road crossings were remediated with additional gravel cover, and one line lowering on shallow pipe was completed.

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 safety inspections of each facility are made by Magellan personnel using a detailed check list called a Facility Safety Review Form. The multi-page form contains 10 sections, each with a list of 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 action items to bring the item into compliance. The topics covered include:

1. Posting of Notices, Signs, and Posters
2. Exits
3. Ladders
4. Hand Held Tools; Fixed Machinery; and Equipment
5. Electrical/Lighting
6. Vehicles and Equipment
7. Flammable Liquids Storage

8. Compressed Gas Cylinders

9. Pump Rooms

10. Miscellaneous

Kiefner received Facility Safety Reviews for two of the pipeline facilities (El Paso East Facility, Crane Station) completed during 2014.

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-6. Number and Status of Action Items per Month for 2014

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	2	5	5	1	9	2	1	2	5	15	32	27	106
Completed	2	5	4	1	8	1	1	1	5	14	29	25	96
Open at End of Month	0	0	1	0	1	1	0	1	0	1	3	2	10

4.9. Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-7. Service Interruptions per Month for 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total*
No./Month	3	2	0	0	2	0	1	1	1	2	2	1	16

* From the Daily Ops Report ending Dec 31, 2014.

4.10. Incorrect Operations and Near-Miss Reports

During 2014 there were 11 incident reports filed; nine occurred at facilities and two along the pipeline. Four of the incidents involved incorrect operations.

Two were classified as near-misses; one involved an incorrect pressure setting due to miscommunication, the other involved a combination of miscommunication and incorrect procedure / system logic which led to a pipeline segment being without leak detection capability.

Two of the 11 incidents were DOT reportable; one involved a release of approximately five barrels of diesel due to a combination of incorrect operation, faulty control logic, and inadequate operating procedures. The other involved a release of approximately 20 gallons of refined product due to valves left open during pigging operations.

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

A complete log of aerial and ground surveillance data is maintained by Magellan and received by Kiefner. 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.

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

There were no ROW near-misses during 2014.

Unauthorized ROW Encroachments (Item 52)

There were 88 encroachments recorded in 2014, none of which were unauthorized.

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 2014 TPD Annual Assessment. There were no One-Call violations in 2014.

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

The 2014 TPD Annual Assessment shows a 25.7 percent drop in non-company activities level from unique aerial patrol observations. This is primarily due to a decrease in housing development, and miscellaneous TP activity.

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

Total possible mileage includes the 694-mile main line plus the 29-mile lateral from Crane to Odessa, and the four 9.4 laterals from El Paso Terminal to Diamond Junction. The 3.5-mile double lateral from East Houston to MP 6 was added to the patrol mileage in 2011. Tier II and Tier III areas (Segment 301) must be inspected every 2½ days not to exceed 72 hours. The Tier I area from the Pecos River to El Paso (Segment 303) 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 over daily from the Pecos River to Galena Park (weather permitting). 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-8. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Aerial Patrol													
301: MP528 to Galena Park	12,679	9,801	12,074	13,548	12,898	13,896	16,597	16,678	14,070	15,160	12,412	9,380	159,193
303: Crane Station to MP694	1,320	1,320	1,056	1,320	1,056	1,056	1,320	1,056	1,056	1,320	1,056	1,056	13,992
Ground Patrol													
Edwards Aquifer	25.2	33.6	22.4	19.6	25.2	16.8	14	11.2	2.8	16.8	19.6	30.8	238

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas (Segment 301) from the Galena Park to Pecos River at least every 72 hours with the following exceptions:

- MP456 to MP528 (2/9-2/11)
- MP354 to MP528 (2/24-2/26)
- MP0 to MP60 (5/25-5/27)
- MP461 to MP528 (6/25-6/27)
- MP52 to MP149 (9/12-9/15)
- MP458 to MP528 (9/12-9/15)
- MP456 to MP528 (10/11-10/13)
- MP456 to MP528 (11/3-11/6)
- Edwards Aquifer (3/27, 9/12, 9/13, 9/15, 9/18, 12/17)

These exceptions were due to episodes of bad weather which prohibited aerial patrols, so ground patrols were organized to complete (or in an attempt to complete) the required right-of-way patrols.

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from Crane to MP694 with the following exceptions.

- No aerial patrol between 2/27 and 3/9
- No aerial patrol between 9/10 and 9/22

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

Table B-9. Markers Repaired or Replaced

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	25	4	5	6	20	2	24	102	70	7	1	0	266

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-10 shows the number of educational and outreach meetings held in 2014.

Table B-10. Educational and Outreach Meetings

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25
School Program:										
School Program - Houston	2	2	3	4		6	5	6	1	3
School Program - Austin	3	2	7	3	4	3	4	5	5	2
Neighborhood Meetings	2	2								
Misc. Meetings:										
Creekside Nursery	1									
Cy Fair ISD	1									
Region 6 LEPC Conference (Houston)	1									
Public Events	4		4	3	2	2				
TOTAL	28	18	25	21	17	22	20	22	17	30

NOTE: Public meetings were tallied for the years 2005-2014 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 2014 is listed in Table B-11 below.

Table B-11. Number of One-Calls by Tier

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	410	367	447	433	450	476	516	418	469	451	368	366	5172
II	869	729	939	855	943	932	949	880	956	1000	833	825	10711
III	286	249	330	313	331	312	310	285	321	314	264	265	3581
Total	1565	1345	1716	1602	1724	1720	1775	1584	1745	1765	1466	1456	19463

Public Awareness Summary Annual Report (Item 60)

The Longhorn Public Awareness Plan incorporates a variety of activities to reach the various stakeholder audiences and provide them with damage prevention information, including annual mailings, emergency response / excavator meetings, door-to-door visits, meetings with emergency response agencies, school presentations, public service announcements and safety information provided on the Magellan website.

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

The number of visits to the safety section of the website per month is shown in the following table.

Table B-12. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Safety/Environment	232	283	212	204	172	178	211	176	208	189	139	188	2392
Pipeline Safety	125	113	122	86	105	91	138	100	98	81	81	116	1266
Call Before You Dig	85	73	145	49	49	44	75	44	59	56	29	49	757
Call Before You Dig Video	2	1	4	4	2	0	1	4	2	1	0	0	20
System Integrity Plan	95	107	88	82	88	83	91	95	78	69	58	68	1002
Longhorn Info.	494	567	646	687	620	537	600	631	564	597	401	419	6763
Pipeline Emergencies	37	43	16	19	21	16	22	22	27	26	21	27	297
Home Page – 811	2	0	0	1	0	0	0	0	1	0	0	1	5

Number of ROW Encroachments by Month (Item 67)

Table B-13. Table of ROW Encroachment by Month

Encroachments	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	14	13	13	0	1	0	20	15	4	6	1	1	88
Unauthorized	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	14	13	13	0	1	0	20	15	4	6	1	1	88

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

No physical hits were reported from 2012 through 2014. Two physical hits to the pipeline requiring coating repair were reported in 2011, while no physical hits were recorded in the previous five years from 2006-2010.

Annual TPD Assessment Report (Item 71)

The Final Longhorn System 2014 Annual Third-Party Damage Prevention Program Assessment (TPD Annual Assessment) was received in August 2015. 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-14 below as extracted from the TPD Annual Assessment. Results show that 19,485 One-Call notifications were made.

Table B-14. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	686	879	1,565
Feb	646	699	1,345
Mar	890	826	1,716
Apr	817	785	1,602
May	884	841	1,725
Jun	874	866	1,740
Jul	833	942	1,775
Aug	727	857	1,584
Sep	792	953	1,745
Oct	845	920	1,765
Nov	627	840	1,467
Dec	642	814	1,456
Totals	9,263	10,222	19,485

4.12. Incident, Root Cause, and Metallurgical Failure Analysis Reports

During 2014 there were 11 internal incident data reports filed, two of which were DOT reportable, both of which occurred at facilities. One was caused by valves left open during pigging operations which led to a release of 20 gallons (0.48 barrels) of refined product. The second involved a booster pump that continued to run after shutdown causing the system to relieve into filter drain boxes during a rain event. The drain system was overwhelmed resulting in the spill of five barrels of diesel. The cause was identified as an error in the control logic and associated operating procedures.

Nine of the incidents occurred at facilities. Six of these incidents were classified as minor. One incident was considered significant which is referred to above (5 barrel release). One was classified as major due to downtime and business loss which involved a scraper pig that got lodged between Cartman and Kimble. One was classified as a near-miss which involved an incorrect pressure setting due to miscommunication.

Two incidents occurred along the pipeline. One of these involved a valve stem packing leak which resulted in a release of two gallons of crude oil. The other pipeline incident was due to a combination of miscommunication and incorrect procedure / system logic which led to a pipeline segment being without leak detection capability. This was considered a near-miss event.

4.13. Other LPSIP/Risk Analyses, Evaluations, and Program Data

Kiefner received the following studies:

- Process Hazards Analyses (PHAs) and Layer of Protection (LOPA) studies for the injection of DRA (drag reducing agent) at Satsuma and Bastrop Stations

- PHA for the El Paso Terminal Revalidation and the Longhorn Expansion Project

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

PHMSA Advisories

DEPARTMENT OF TRANSPORTATION ADB-2014-05 October 15, 2014
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2014-0086
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: PHMSA published Advisory Bulletin ADB-2012-10 in the Federal Register on December 5, 2012, to remind operators of gas transmission and hazardous liquid pipeline facilities of their responsibilities under current regulations to perform evaluations of their Integrity Management (IM) programs using meaningful performance metrics. PHMSA is issuing this Advisory Bulletin to expand that reminder by informing owners and operators of gas and hazardous liquid pipelines that PHMSA has developed guidance on the elements and characteristics of a mature program evaluation process that uses meaningful metrics.

DEPARTMENT OF TRANSPORTATION ADB-2014-04 September 18, 2014
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2014-0400
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: PHMSA is issuing this advisory bulletin to alert operators of hazardous liquid and gas transmission pipelines of the potential significant impact flow reversals, product changes and conversion to service may have on the integrity of a pipeline. Failures on natural gas transmission and hazardous liquid pipelines have occurred after these operational changes. This advisory bulletin describes specific notification requirements and general operating and maintenance (O&M) and integrity management actions regarding flow reversals, product changes and conversion to service. This advisory bulletin also recommends additional actions operators should take when these operational changes are made including the submission of a comprehensive written plan to the appropriate PHMSA regional office regarding these changes prior to implementation.

DEPARTMENT OF TRANSPORTATION ADB-2014-03 September 12, 2014
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2014-0017
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: PHMSA is issuing this advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to provide further clarification regarding the notification(s) required prior to certain construction-related events.

PHMSA needs to be aware of certain construction-related events to have sufficient time to schedule reviews of pipeline construction plans and inspections. Moreover, timely construction plan reviews and inspections by PHMSA could help operators avoid costly modifications, repairs and/or additions to achieve compliance with the Federal pipeline safety regulations. Accordingly, PHMSA strongly encourages operators to provide the required construction-related notification(s) not later than 60 days prior to whichever of the following activities occurs first: Material purchasing and manufacturing; right-of-way acquisition; construction equipment move-in activities; onsite or offsite fabrications; or right-of-way clearing, grading and ditching.

PHMSA also strongly encourages operators to provide the required notification(s) for the construction of 10 or more miles of a new pipeline for a pipeline that: (1) Did not previously exist; and (2) for the replacement of 10 or more contiguous miles of line pipe in an existing pipeline.

DEPARTMENT OF TRANSPORTATION ADB-2014-02 May 6, 2014
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2014-0020
Pipeline Safety: Lessons Learned From the Release at Marshall, Michigan
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: PHMSA is issuing an advisory bulletin to inform all pipeline owners and operators of the deficiencies identified in Enbridge's integrity management (IM) program that contributed to the release of hazardous liquid near Marshall, Michigan, on July 25, 2010. Pipeline owners

and operators are encouraged to review their own IM programs for similar deficiencies and to take corrective action. Operators should also consider training their control room staff as teams to recognize and respond to emergencies or unexpected conditions. Further, the advisory encourages operators to evaluate their leak detection capabilities to ensure adequate leak detection coverage during transient operations and assess the performance of their leak detection systems following a product release to identify and implement improvements as appropriate. Additionally, operators are encouraged to review the effectiveness of their public awareness programs and whether local emergency response teams are adequately prepared to identify and respond to early indications of ruptures. Finally, this advisory reminds all pipeline owners and operators to review National Transportation Safety Board recommendations following accident investigations. Owners and operators should evaluate and implement recommendations that are applicable to their programs.

DEPARTMENT OF TRANSPORTATION ADB-2014-01 January 28, 2014
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2014-0226
ACTION: Notice; Issuance of Advisory Bulletin.
SUMMARY: Conforming Facility Response Plans (FRPs) to Appendix A to Part 194—"Guidelines for the Preparation of Response Plans" and Identifying Deficiencies.

PHMSA is issuing this advisory bulletin to remind all onshore oil pipeline operators of the circumstances of the Marshall, Michigan, pipeline accident and the need to update FRPs every five years from the date of last submission or the last approval according to its significant and substantial designation. Plans must also be updated whenever new or different operating conditions would affect the implementation of a response plan. (See 49 CFR 194.121.) When updating their FRPs, operators should utilize Appendix A Part 194—Guidelines for the Preparation of Response Plans and submit them electronically to PHMSA.

This bulletin also notifies that FRPs found to meet the requirements of PHMSA's regulations at Part 194 will be posted on PHMSA's Web site for public viewing. Prior to posting, PHMSA will redact certain information, such as personally identifiable information and certain security related information, in accordance with the Freedom of Information Act and any other applicable Federal law. This document also alerts operators and their plan submitters to common errors in plans that require amendment prior to PHMSA's issuance of approval. Finally, onshore oil pipeline operators are encouraged to consider replacing incorporations by reference in their FRPs with a summary of referenced material or a copy of the full document**.**

4.15. DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2014.

4.16. Literature Reviewed

See references.