Magellan Pipeline Company

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2015 Operational Reliability Assessment of the Longhorn Pipeline System

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Dennis Johnston, and Dyke Hicks

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Final Report

on

2015 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

March 28, 2017

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EXECUTIVE SUMMARY

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2015 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which is intended to provide Magellan Pipeline Company, L.P. (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 to evaluate the 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.

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, an integrity reassessment from the standpoint of potential flaws in the electric-resistance weld (ERW) and flash welded (FW) seam will be necessary in the year 2020 for the Buckhorn to Warda and Warda to Bastrop segments. No fatigue related failures occurred in 2015. Transverse field inspection (TFI) tool runs, completed in 2007, 2008, and 2015 were used to define a flaw size that determined the reassessment interval. Seventy-five seam weld features were identified during the 2007-2008 TFI and subsequently remediated. Thirteen seam weld features were identified during the 2015 TFI and were scheduled to be remediated during 2016. Therefore, the reassessment interval used the seam weld feature detection threshold value from the TFI tool vendor.

The run-to-run comparison of corrosion identified by the 2015 in-line inspection (ILI) assessments compared with previous ILI assessments indicated an upper bound external corrosion growth rate (CGR) in the range of 5.0 mpy. These external CGRs exhibit similar rates to CGRs that were established in a previous CGR study conducted in 2011 by a third party. These previously established CGRs were utilized to determine the probability of exceedance (POE) for all features reported from the magnetic flux leakage (MFL) assessments. Three anomalies were recommended for excavation due to their POE rating. The 2015 POE analysis resulted in a rate of 0.013 POE digs per mile. This is in the same range as the POE dig rates reported since 2009. Internal corrosion coupons continue to show very minor (<0.12 mpy) corrosion rates. The TFI final report notes debris present throughout the entire segment between Eckert to Texon. Magellan should continue to conduct field investigations to remediate and validate metal loss.

- Kiefner recommends that Magellan conduct a review of cleaning tool results prior to ILI inspections on these segments.

One of the dents identified through ILI is located within a high consequence area (HCA) (between James River and Eckert) with a depth of 2.46% on the bottom of the pipe.

- Kiefner recommends this dent be considered for a secondary review of the ILI data and excavation if it is found to be a dent with metal loss. (Note: Magellan plans to complete this repair in January 2016.)

- Kiefner also recommends that additional digs be conducted on metal loss features in order to statistically validate the performance of the ILI tools from the 2015 ILI assessments. To statistically validate the tool performance, a minimum of five metal loss features per tool type and segment assessed is needed. Preferably the metal loss validation features are obtained from more than one dig. (Note: Magellan plans to conduct additional digs in 2016 which should allow for tool validation.)

In the 2014 ORA report, a reliability-based design analysis (RBDA) was recommended as an alternative methodology of calculating a corrosion feature's probabilistic integrity threat. The advantage of RBDA is that it incorporates the measurement uncertainty addressed by POE in addition to other uncertainties. During 2015, the POE analysis was reviewed and compared with RBDA results. Because of the complexity of RBDA, it takes longer to obtain the results for each feature in the analysis than POE and can give little to no additional benefit to features that already have a POE less than 1×10^{-5}. Therefore, POE should remain as the main probabilistic analysis on Longhorn pipelines.

- It is recommended that RBDA then be considered for features that have a POE equal to or greater than 1×10^{-5}.

This will reduce the time needed to perform the analyses and to get a more accurate understanding of probabilistic integrity threats that these features may pose to the pipeline.

A Close Interval Survey (CIS) was performed by a third party in July 2015 on Longhorn Tier III (environmentally sensitive) sections. Conclusions from the CIS indicated that some sections of the pipeline do not meet the criteria set by NACE[1] SPO 169-2007. Also, there are approximately 1,974 feet where the "On" potentials are greater than -2 volts. Additional surveys of the cathodic protection (CP) system were recommended to determine a status for each segment.

[1] NACE International, formerly known as the National Association of Corrosion Engineers.

Magellan determined that the CIS exceptions were the result of a rectifier that was out during the survey. The rectifier was re-energized on the same day it was found down. Follow-up testing confirmed that reenergizing the rectifier addressed the issue.

Laminations and hard spots were reviewed concurrently with reported geometric anomalies to determine if there were any potential hydrogen blisters on the line segments inspected in 2015. The deformations identified from the 2015 ILI assessments were compared to the existing laminations found from the 2010 ultrasonic testing (UT) assessments and no features correlated. Based on the 2015 maintenance reports and ILI assessments, there are currently no potential hydrogen blisters associated with these line segments. There were no hard spot investigations done in 2015. With the conversion of the pipeline back to crude oil service and the reintroduction of hydrogen sulfide, Magellan should continue to monitor for lamination anomalies for the possibility of blister growth with ILI tools.

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. The results of our analysis show that movement on six of the seven faults continues to be so small that ground movement will not be a threat to the pipeline. An updated analysis of allowable fault displacement at the Hockley fault was conducted for the 2014 and 2015 ORAs. It was determined that the movement at the Hockley Fault is sufficiently active to raise some concern and three options of remediation were provided in the 2014 ORA and included in Section 3.4 and 9 of this ORA.

- Because of this slow rate of fault movement, Kiefner recommends a five-year reassessment rather than the current semi-annual program, except for the Hockley fault.

Semi-annual scour surveys and waterway inspections of the Colorado River crossing and its tributary Pin Oak Creek were conducted in 2015. No exposures of the pipeline at the waterways were found; however, there is a 6-foot section near the west bank of the Pin Oak Creek with a DOC less than or equal to one foot. Magellan should continue to perform scour and waterway inspections at the current frequency to monitor the conditions perform further remediation of the Pin Oak Creek DOC as necessary.

The five-year aerial inspection was also completed in 2015. The aerial inspection found changes at four locations of previously identified areas of concern (AOCs), three new AOCs and one area of elevated concern (AOECs). The report recommended that a more detailed inspection of the AOECs and areas showing exposed or potentially exposed pipeline sections be conducted.

- Kiefner agrees with the third party recommendation for a more detailed inspection of the AOECs and areas showing exposed or potentially exposed pipeline sections.

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 (low-level flight) and ground patrol frequencies exceeded the frequencies set forth in the Longhorn Mitigation Plan (LMP). There were four right-of-way (ROW) near-misses, three of which were one-call violations which were promptly addressed. There were no known cases of third-party contact with the pipeline during 2015. 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. For the threat of TPD, Magellan should continue both prevention and inspection activities.

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. 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.

From the standpoint of facilities data acquired in 2015, one can conclude that pump stations and terminal facilities have been properly maintained and operated and have had no adverse impact on public safety. Magellan should continue its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

A probabilistic risk model has been effectively used to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The results show none of the pipeline segments exceeded Magellan's risk threshold; therefore no additional mitigative measures were required or recommended.

The technical assessment of the Longhorn Pipeline System Integrity Plan (LPSIP) indicated 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 and frequency. In addition, public-awareness meetings were held, and ROW markers and signs were repaired or replaced where necessary. In terms of failure measures, there were no Department of Transportation (DOT) reportable incidents or third-party contact with the pipeline or facilities.

Magellan performs incident investigations on all DOT-reportable incidents as well as smaller non-reportable incidents and near-miss events. During 2015, there were 18 non-reportable incidents along the Longhorn Pipeline System. Eight of the 18 incidents were classified as minor, one significant, and nine were near-misses. The significant incident occurred at Crane Station during excavation for new cable tray supports where the driller hit a live electrical line. The significant classification was based on property damage; no injuries occurred.

Magellan should continue to ensure all relevant data are 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.

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

AOC – Area of concern

AOEC – Area of elevated concern

API – American Petroleum Institute

ASME – American Society of Mechanical Engineers

bpd – barrels per day

bph – barrels per hour

CFR – Code of Federal Regulations

CGR – Corrosion growth rate

CIS – Close interval survey

CMFL – Circumferential magnetic flux leakage

CMP – Corrosion Management Plan

CMS – Content Management System

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).

Dent – An ID Reduction greater than or equal to 2% of pipe diameter

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.

EGP – Electronic geometry pig

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.

FEA – Finite element analysis

FW – Flash welded

GE – GE Energy

Geometric Anomaly (GMA) – An ID Reduction less than 2% of pipe diameter

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

HR – High Resolution

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

H_2S – Hydrogen Sulfide

ID Reduction – A deformation of pipe diameter detected by the ILI tool

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.

Ipy - Inches per year – Often referenced in conjunction with corrosion growth rates (1000 mpy)

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).

Kiefner – Kiefner and Associates, Inc.

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.

Magellan – Magellan Pipeline Company, L.P.

Major Incident **–** Includes events which result in:

- Fatality
- Three or more people hospitalized
- Major news media coverage
- Property loss, casualty, or liability potentially greater than $500,000
- Major uncontrolled fire/explosion/spill/release that presents imminent and serious or substantial danger to employees, public health, or the environment

MASP – Maximum Allowable Surge Pressure

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

Minor Incident – Includes events which result in:

- Fire/explosion/spill/release or other events with casualty/property/liability loss potential under $25,000
- Employee or contractor OSHA recordable injury/illness without lost workday cases
- Citations under $25,000

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.

MG – Metal gain

mil – One thousandth of an inch (0.001 in)

ML – Metal loss

MOCR – Management of Change Recommendation

MOP – Maximum Operating Pressure

MP – Mile Post

MTR – Mill Test Report

Mpy – Mils per year – Often referenced in conjunction with corrosion growth rates. (0.001 ipy)

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.

NEPA – National Environmental Policy Act

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.

One-Call Violations – Number of excavations that occurred within the ROW boundaries where a one-call was not made and should have been made. Texas One-Call (Utilities Code: Title 5, Chapter 251, Section 251.002, Sub-Section 5) defines excavate as "to use explosives or a motor, engine, hydraulic or pneumatically powered tool, or other mechanized equipment of any kind and includes auguring, backfilling, boring, compressing, digging, ditching, drilling, dragging, dredging, grading, mechanical probing, plowing-in, pulling-in, ripping, scraping, trenching, and tunneling to remove or otherwise disturb soil to a depth of 16 or more inches." Additionally, one-call violations are identified when company personnel discover third-party activity on the ROW and inform the third party that a one-call is required. One-call violation data are obtained from Hazard / Near Miss cards, One-Call tickets, incident investigations, aerial patrol reports, maintenance reports and ROW inspection reports.

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 Operational Reliability Assessment Process Manual

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

PLM – Pipeline Monitor

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% 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}.

POF – Probability of Failure

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).

Significant Incident – Includes events which result in:

- Fire/explosion/spill/release/ less than three hospitalized or other events with casualty/property/liability loss potential of $25,000 - $500,000
- Employee or contractor OSHA recordable injury/illness lost workday cases
- Citations with potential fines greater than $25,000

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)

SIP – System Integrity Plan

SMYS – Specified Minimum Yield Strength

Tier I Areas – Areas of normal cross-country pipeline

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

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

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

TPD –Third-party damage

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

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

UT – Ultrasonic testing – a non-destructive testing technique using ultrasonic waves

WT – Wall thickness of line pipe

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Susan Rose, Adam Steiner, Benjamin Wright, Fan Zhang, Dennis Johnston, and Dyke Hicks

1. INTRODUCTION

1.1. Objective

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2015 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which is intended to provide Magellan Pipeline Company, L.P. (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 to evaluate the 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.

1.2. Background

The previous owner, Longhorn Partners Pipeline, LP, participated in an Environmental Assessment (EA) that was prepared by the U.S. Environmental Protection Agency (EPA) and the Department of Transportation (DOT) in 1999 and 2000, prior to the then newly configured pipeline refined product service. 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 included the Longhorn Continuing Integrity Commitment wherein Longhorn agreed to implement System Integrity and Mitigation Commitments and conduct annual ORAs. A list of the Longhorn Mitigation Commitments (LMCs) addressed in the ORA report is provided in Appendix A – Mitigation Commitments. Magellan has operated the Longhorn system since 2005 and has owned it since 2009.

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 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. The “Mock ORA for Longhorn Pipeline” that was performed by Kiefner prior to commissioning of the pipeline provided additional information on the execution of the ORA. The ORAPM requires the ORA contractor to provide annual reports to Magellan and 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 (TPD)
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 pipeline operators had not recognized SCC as a threat in the past.

1.3. 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 12 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

Figure 1 provides a process schematic of the functions and relative interactions of the LPSIP and the ORA.

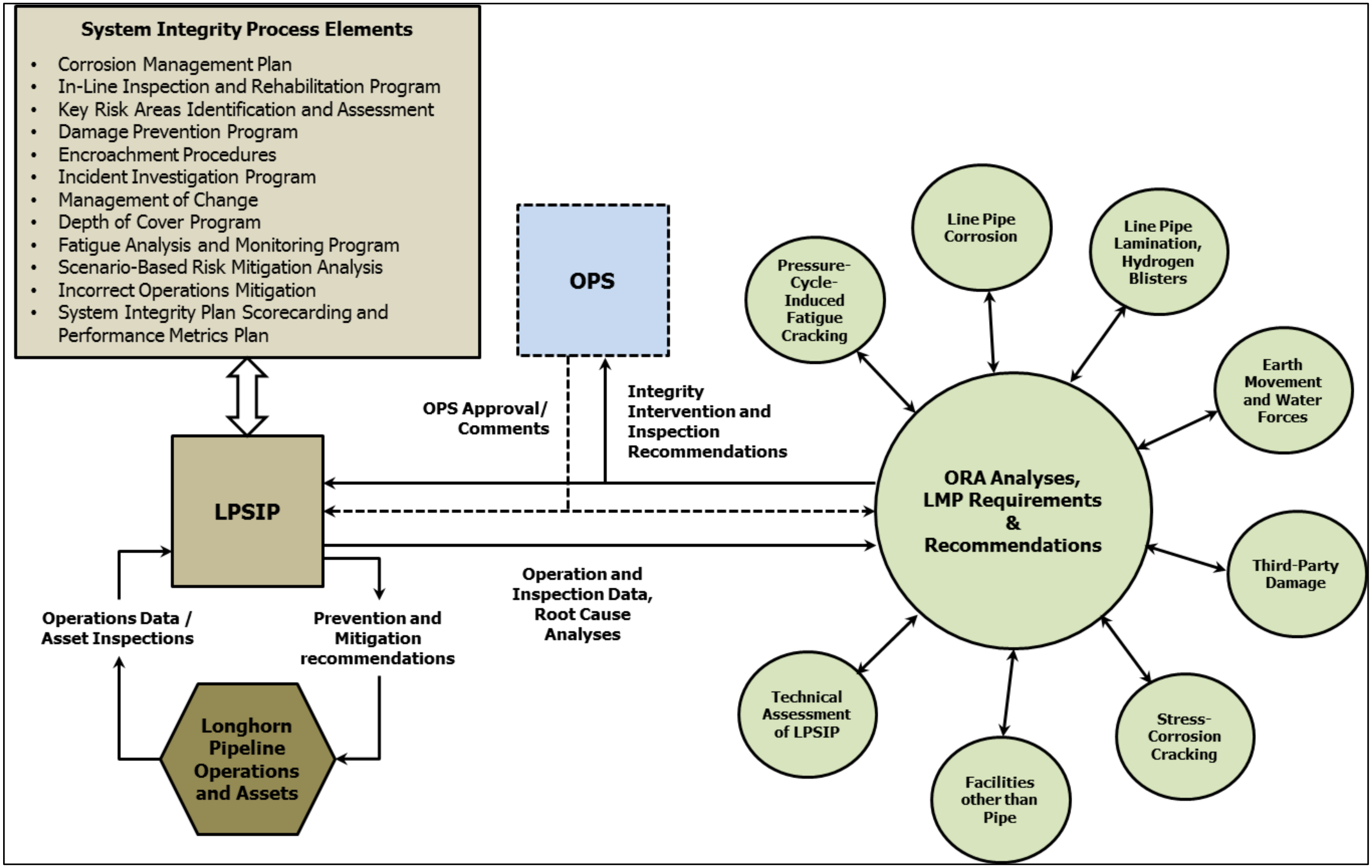

Figure 1. ORA Functions and Interaction with the LPSIP

1.4. 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 on August 17, 2012. The Longhorn systems returned to service in April 2013 and are described below. The Longhorn System Map is presented in Figure 2 with a detailed map of the Houston area shown in Figure 3.

The western portion of the 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 eastern portion of the Longhorn system transports crude oil over 424 miles through an 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 pipe from Satsuma Station to the East Houston Terminal and nine miles of 20-inch pipe from East Houston Terminal to 9th Street Junction. This system contains some of the Existing Pipeline (as named in the original EA) built in 1949-1950, with some replacements and extensions in the Houston area. The station locations for the crude oil and refined product systems are listed below in Table 1 and Table 2.

Table 1. Crude Pipeline Station Locations

Station	Type	MP
Crane	Pump	457.5
Texon	Pump	416.6
Barnhart	Pump	373.4
Cartman	Pump	344.3
McKavett	Valve	324.0
Kimble County	Pump	295.2
James River	Pump	260.2
Eckert	Pump	227.9
Cedar Valley	Pump	181.6
Bastrop	Pump	141.8
Warda	Pump	112.9
Buckhorn	Pump	68.0
Satsuma	Pump	34.1
E. Houston	Terminal	0

Table 2. Refined Product Pipeline Station Locations

Station	Type	MP
Odessa[2]	Meter	NA
Crane	Pump	457.5
Cottonwood	Valve	576.3
El Paso	Terminal	694.4

During 2014 there was an increase in the flow rate from 225,000 to 292,000 barrels per day (bpd) from Crane to East Houston and an increase to 2,100 barrels per hour (bph) on the Western refinery connection at El Paso. The "connection" is an 8-inch flush line between El Paso and El Paso Junction. There were no operational changes to the Longhorn Pipeline System during 2015.

A timeline of the Longhorn Pipeline System is provided in Figure 4.

[2] The Longhorn Mitigation Plan (LMP) covers the Odessa pig trap. The tanks and metering are not covered by the LMP.

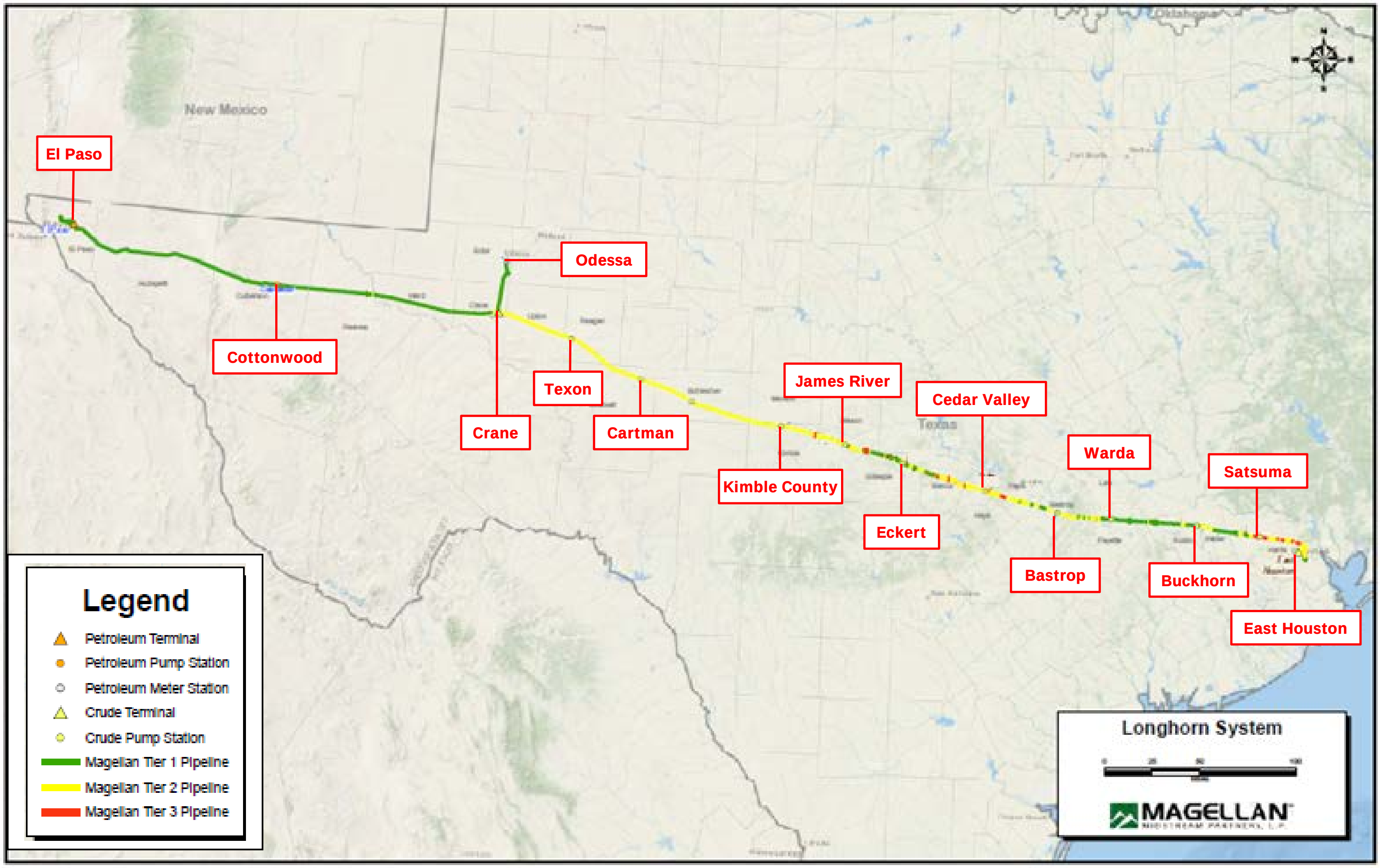

Figure 2. Longhorn System Map 2015

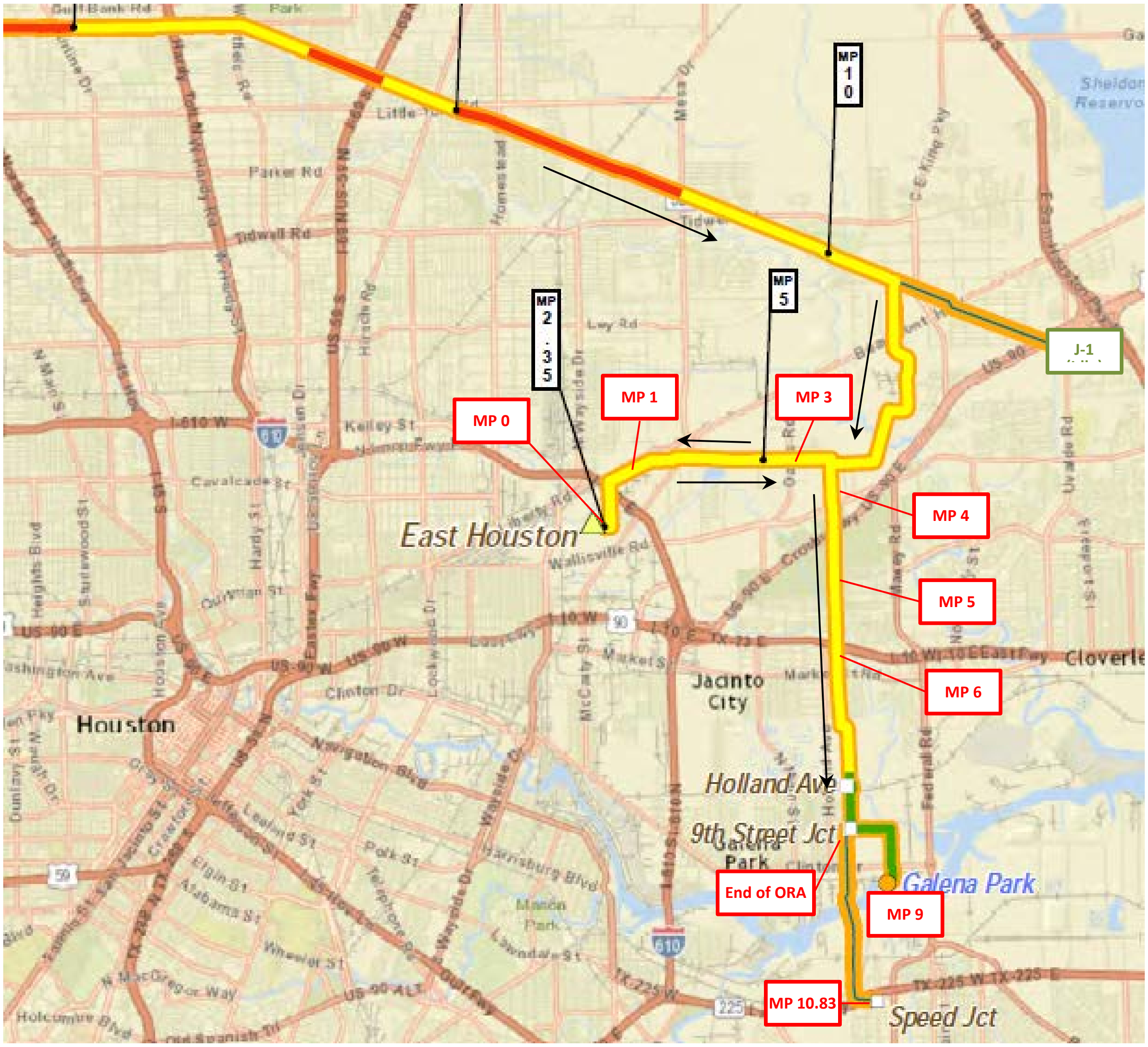

Figure 3. Map of Longhorn System within Houston Area

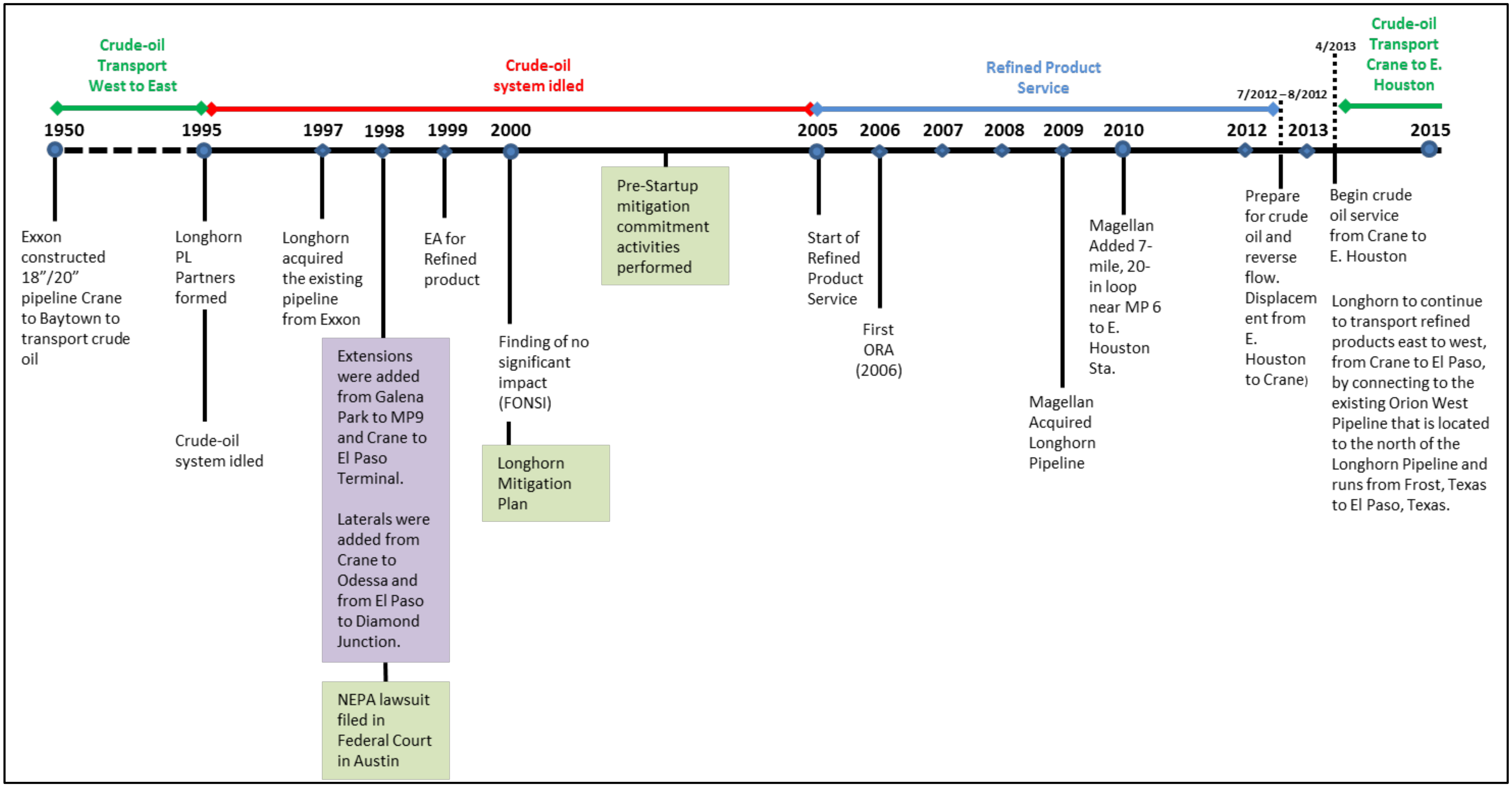

Figure 4. Timeline of the Longhorn Pipeline System

1.5. Analysis Information

The ORA Process Manual identifies the list of data needed to conduct the ORA. These data items are discussed in Appendix B of this report.

2. TECHNICAL ASSESSMENT OF LPSIP EFFECTIVENESS

The LPSIP contains 12 process elements which 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.

2.1. Longhorn Corrosion Management Plan

The LMP entails an extensive Corrosion Management Plan (CMP) to control the extent of corrosion. The CMP looks at the following items: corrosion growth rates (CGRs), review of internal corrosion coupons, POE analysis for MFL assessments, review of field dig reports (covered under the In-Line-Inspection and Rehabilitation Program section), and review of the cathodic protection system. CGRs for external metal loss were found to be in the range of 5.0 mpy; field investigations to remediate and validate metal loss should continue. Internal corrosion is monitored using internal corrosion coupons. The coupon results have shown little change (<0.12 mpy) but monitoring should continue. Results from the internal corrosion coupons can be found in Appendix B, Table B-4.

In the 2014 ORA report, a reliability-based design analysis (RBDA) was recommended as an alternative methodology of calculating a corrosion feature's probabilistic integrity threat. The advantage of RBDA is that it incorporates the measurement uncertainty addressed by POE in addition to other uncertainties. This provides a more comprehensive understanding about the various factors that can affect an integrity threat to the pipeline, whether these factors increase the probability of failure or provide additional protection mitigating the probability of failure. The POE analysis was reviewed and compared with RBDA. More information on RBDA can be found in Section 5, ORA Process Improvements.

Results indicated that RBDA has similar probabilities to POE using the probability of rupture and probability of leak assumptions (results can be found in Table 4). Due to the complexity of RBDA, it takes longer to obtain the results for each feature in the analysis than POE and can give little to no additional benefit to features that already have a POE less than 1×10^{-5}. Therefore, POE should remain as the main probabilistic analysis on Longhorn pipelines and be used to identify features that could pose a probabilistic integrity threat to the pipeline. It is recommended that RBDA then be performed on the features that have a POE equal to or greater than 1×10^{-5}. This will reduce the time needed to perform the analyses and to get a more accurate understanding of probabilistic integrity threat that each of these features pose to the pipeline.

RBDA could be improved if more information on the pipeline and ILI tool run is obtained. This would include more information on the pipe properties like mill test reports (MTR) and how well the tool performed from field investigations.

A Close Interval Survey (CIS) was performed by Matcor from July 14 through July 27, 2015, on Longhorn Tier III sections (environmentally sensitive areas due to population or environmental factors). Conclusions from the CIS indicated that 59 feet of the pipeline do not meet the 100mV shift criteria set by NACE SPO 169-2007. Also, there are approximately 1,974 feet where the “On” potentials are greater than -2 volts.

Magellan determined that the CIS exceptions were the result of a rectifier that was out during the survey. The rectifier was re-energized on the same day it was found down. Follow-up testing confirmed that reenergizing the rectifier addressed the issue.

2.2. In-Line-Inspection and Rehabilitation Program

ILI assessments were performed between the Satsuma (MP 34.1) and Crane (MP 457.5) pump stations. Two different ILI assessments were performed over this segment; MFL technology was used from Satsuma to Eckert (MP 227.9) and TFI technology was used from Eckert to Crane. Inspection dates for each segment can be found in Table 5. A deformation tool accompanied both the MFL and TFI tool runs.

The 2015 TFI ILI assessments reported more internal features when compared with the previous TFI assessments completed in 2007. This is due to an increase in anomalies reported to be 10 to 20% of wall thickness (WT). Possible explanations for the large difference in shallow features reported include: 1) debris in the line and tool tolerance and 2) reporting criteria. GE Energy (GE) noted in the TFI ILI report that debris was present throughout the entire inspection on the segments between Eckert to Texon. On the Crane to Texon segment, GE noted debris was detected from the start of the inspection to 3,000 feet and then light debris throughout the remainder of the inspection. GE stated that in areas where debris is located the capability to detect small features is reduced and could affect ID/OD discrimination. Based on this, Kiefner recommends that Magellan conduct a review of cleaning tool results prior to ILI inspections on these segments.

The 2015 ILI assessments and maintenance reports were reviewed to validate the ILI specified tool performance. The ILI assessments were reviewed with an understanding of the background and approach for API 1163 ILI validation. The ILI assessments passed an API 1163 Level 1 validation. Note: if a segment of pipe does not have material documentation available Magellan requires non-destructive testing of said pipe segment to determine pipe properties in at least 50% of the excavations or remediation required by ILI results.

Magellan provided 10 maintenance reports related to ILI investigations. The ILI investigation digs correlated to 19 ILI features (geometric anomalies, geometric anomalies with metal loss, metal loss, and lack of fusion) that were remediated in 2015 from the most recent ILI assessments. The dig results are shown in Table 13. Three of the 19 correlated ILI features were reported as metal loss and found to be lack of fusion. Seven of the 19 correlated ILI features were metal loss to metal loss comparisons. Six of the seven metal loss comparisons had an actual depth that was within the specified tool performance. A Level 2 validation was not performed because there were an insufficient number of metal loss validations to perform a statistical analysis on metal loss features. Additional digs for metal loss features are recommended to statistically validate the performance of the ILI tools from the 2015 ILI assessments. To statistically validate the tool performance, a minimum of five metal loss features per tool type and segment assessed is needed. Preferably the metal loss validation features are obtained from more than one dig. Magellan plans to conduct additional digs in 2016 which should allow for tool validation.

2.3. Key Risk Areas Identification and Assessment

The objective of Magellan's risk management program is to ensure that resources are focused on those areas of the Longhorn Pipeline System with the highest identified or perceived risk.

Since the Longhorn Pipeline System traverses a variety of unique areas of land use, topography, and population density, it presents a variety of risk concerns to these lands and to the people who either inhabit or are present in these areas. To help prioritize risk management efforts, Magellan has categorized the Longhorn Pipeline System with the following designations: Tier I (normal cross-country pipeline), Tier II (sensitive areas), and Tier III (hypersensitive areas). Further, the area across the Edwards Aquifer in South Austin is a Tier III designated area of additional heightened environmental sensitivity that has resulted in even more scrutiny and the commitment to incremental risk mitigation measures.

Magellan's probabilistic risk model utilizes integrated data and incorporates a dynamic segmentation process to maintain adequate resolution and avoid mischaracterization or loss of detail. The risk measurement methodology includes Probability of Failure (POF) threshold management to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452.

The POF measurement integrates all available information about the integrity of the pipeline. This integration aids in identification of preventive and mitigative measures to protect areas along the pipeline. Magellan is committed to maintaining a threshold of 1x 10^{-4} (0.0001) failures (PHMSA reportable incidents) per mile-year at all locations along the non-facilities portions of the pipeline.

The pipeline risk model was updated with information from operations in 2015. The results show none of the pipeline segments exceeded the risk threshold; therefore no additional mitigative measures were required or recommended.

2.4. 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 2015.

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.

2.5. Encroachment Procedures

Encroachments are unannounced or unauthorized entries of the pipeline right-of-way (ROW) 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 are considered encroachments.

The LPSIP includes provisions for surveillance to prevent and minimize the effects of right-of-way encroachments.

There were 44 encroachments recorded in 2015, two of which were unauthorized. Both were followed up with corrective actions to help prevent a recurrence. The encroachment procedures, when followed by the encroaching party, have been effective at preventing TPD to the pipeline.

2.6. Incident Investigation Program

Magellan is performing incident investigations on all DOT-reportable incidents as well as smaller non-reportable incidents and near-miss events.

During 2015, there were 18 incidents along the Longhorn Pipeline System. Two of these involved releases, but were not DOT-reportable. Four of the incidents occurred along the pipeline and 14 occurred at facilities. Of the four pipeline related incidents, three were one-call violations.

Eight of the 18 incidents were classified as minor and one was significant. The significant incident occurred at Crane Station during excavation for new cable tray supports where the driller hit a live electrical line. The significant classification was based on property damage; no injuries occurred. There were five ROW near misses and two hazard near misses.

Magellan should continue to ensure all relevant data are 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.

Appendix B, Section B.12 provides additional information on the incidents which occurred during 2015.

2.7. Depth-of-Cover Program

Three new exposures were identified in 2015 and subsequently additional cover was added. One site that has been actively managed under the Outside Forces Damage Prevention Program in accordance with the LPSIP was also repaired after additional erosion was found. Additionally, nine road crossings and three ditch water crossing areas were remediated along the line. There was no third-party damage found at any of the remediated locations.

No exposures of the waterways were found; however the depth of cover above two segments is less than one or two feet and will continue to be monitored.

As ongoing monitoring, landowners are contacted annually to reaffirm that cultivation techniques and land use have not changed. Magellan monitors this on a regular basis to ensure that landowner farming practices do not jeopardize the integrity of the pipeline.

2.8. Fatigue Analysis and Monitoring Program

The 2015 fatigue analysis incorporated results from the 2007 and 2015 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. From the new data obtained during the 2015 TFI tool runs, the shortest time to reassessment is calculated to be 2020. The analysis for this program is covered under Section 6.1 of this report.

2.9. Scenario-Based Risk Mitigation Analysis

The objective of Magellan's Scenario-Based Risk Mitigation Analysis (SBRMA) program is to identify preventive measures and/or modifications that can be recommended that would reduce the risks to the environment and the population in the event of a product release.

Magellan's risk model is updated periodically as new information becomes available. Process Hazard Analyses (PHAs) are performed on all new facilities or changes to facilities. None were required during 2015.

Magellan has set a target for probability of failure at 1×10^{-4}. Where the probability of failure does not meet this threshold, risk reduction measures are recommended.

2.10. Incorrect Operations Mitigation

The objective of the Incorrect Operations Mitigation Program is to identify and subsequently reduce the likelihood of human errors that could impact the mechanical integrity of the Longhorn Pipeline System.

As discussed in Section 2.6, 14 of the 18 incidents during 2015 involved human error; most of which were due to procedures not being followed or incorrect procedures and/or instructions. Three of these incidents involved incorrect valve lineups to station tanks leading to line overpressure and system shutdown.

Cases of incorrect operations have been formally documented and investigated and corrective actions have been implemented.

2.11. Management of Change Program

Magellan has established an effective program to manage changes to process chemical, technology, equipment, procedures, and facilities across the Longhorn Pipeline System.

The Longhorn Mitigation Plan (LMP) requires that all changes on the Longhorn system be evaluated using an appropriate Process Hazard Analysis (PHA). The Magellan Management of Change Recommendation (MOCR) form is used to document whether a PHA is required and Magellan's procedures provide that the asset integrity engineer should determine the appropriate PHA methodology for change requests. One PHA was conducted in 2015 for a pending project that will provide additional product to East Houston with the potential to pump to Speed Junction; however, it is currently not expected to impact LMP physical assets.

2.12. System Integrity Plan Scorecarding and Performance Metrics Plan

Magellan has implemented an effective method for evaluating the effectiveness of the LPSIP on an annual basis using performance measures (or scorecarding) 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 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, there were five digs: three POE evaluation digs and two immediate conditions from the 2015 ILI runs, both immediate conditions were dents with metal loss within a high consequence area (HCA). In terms of failure measures, there were no DOT-reportable incidents or third-party contact with the pipeline or facilities.

Specific details are presented in Section 7 of this report.

3. INTERVENTION MEASURES AND TIMING

3.1. Pressure-Cycle-Induced Fatigue

For the threat of pressure-cycle-induced fatigue, a reassessment in the year 2020 for the segment with the shortest time to failure was calculated based on the pressure cycles since the most recent TFI tool run for each segment. The next assessments are as follows:

- Speed Junction to East Houston (MP 10.83 to MP 2.35): 15-May-2214
- East Houston to Satsuma (MP 2.35 to MP 34.1): 14-Sep-2027
- Satsuma to Buckhorn (MP 34.1 to MP 68.0): 15-Jun-2028
- Buckhorn to Warda (MP 68.0 to MP 112.9): 27-Dec-2020
- Warda to Bastrop (MP 112.9 to MP 181.6): 16-Jun-2020
- Bastrop to Cedar Valley (MP 141.8 to MP 181.6): 6-Mar-2039
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 1-Aug-2023
- Eckert to James River (MP 227.9 to MP 260.2): 9-Jul-2027
- James River to Kimble County (MP 260.2 to MP 295.2): 25-Sep-2034
- Kimble County to Cartman (MP 295.2 to MP 344.3): 23-Nov-2024
- Cartman to Barnhart (MP 344.3 to MP 373.4): 16-Dec-2053
- Barnhart to Texon (MP 373.4 to MP 416.6): 9-Sep-2024
- Texon to Crane (MP 416.6 to MP 457.5): 24-Apr-2023
- Crane to El Paso (MP 457.5 to MP 694.4): 29-Nov-2238

3.2. Corrosion

For the threat of corrosion, a reassessment schedule can be found in Section 8, Table 19 for the Longhorn crude system and in Table 20 for the Longhorn refined system. For the crude system the next round of corrosion assessments is in 2019 for Warda through Speed Junction. For the refined system the next round of corrosion assessments is 2016 for Crane to Odessa.

3.3. Laminations and Hydrogen Blisters

For the threat of laminations and hydrogen blisters, a reassessment schedule can be found in Section 8, Table 19 for the Longhorn Crude System and in Table 20 for the Longhorn Refined System. Per the Longhorn EA Section 9.3.2.3 the monitoring frequency recommended should coincide with the EGP tool assessment schedule. Section 9.3.2.3 requires an EGP assessment every three years in accordance with the LMP. The deformations identified from these assessments will be correlated with the existing laminations found from the 2010 UT assessments. For the crude system the next round of EGP assessments is 2017 for Speed Junction through Warda. For the refined system the next round of EGP assessments is 2016 for Crane to Odessa.

3.4. Earth Movement and Water Forces

Earth Movement

The earth movement analysis continues to show that any movement on the seven monitored faults 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 faults rather than the current semi-annual program, except the Hockley Fault. If the faults appear to become more active, then more frequent measurements can be implemented. The movement at the 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. Three potential paths for remediation were provided in the 2014 ORA and repeated 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 provided in the 2014 ORA, 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 that the quality of the girth welds in the exposed segment be examined at this time.

- Option 2: If there is an existing inertial pigging record or internal pigging is scheduled in the near future, the level of current accumulated stresses in the pipe can be estimated.

It could then be used to determine an accurate value of the additional fault displacement that can be accommodated by the pipe before failure.

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

Water Forces

Scour inspections were completed in June and December of 2015 for both the Colorado River and Pin Oak Creek crossings. The scour inspections provide an indirect way to assess the remaining cover above the pipeline based on the scour condition of the banks. Waterway inspections were also conducted in July of 2015 which measured the remaining depth of burial of the pipeline in the waterway. Based on the inspection results, Magellan should continue the current practices for these two crossings including the bi-annual scour inspections and the waterway inspections every five years as specified by studies referenced in LMC 19.

3.5. 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 2015. Inspection activities include ILI assessments required per the ORA using "Smart Geometry" tools (EGP) and High Resolution MFL or UT tools. LMC 12A requires ILI assessments for TPD detection between Valve J-1 and Crane Station be carried out within three years of a previous inspection. (Note that the 2-mile section from Valve J-1 to MP 9 is no longer in use). ILI assessments were conducted in 2015 on all 11 segments between Satsuma and Crane. MFL inspection tools were used on the five segments from Satsuma to Eckert and TFI inspection tools were used on the six segments from Eckert to Crane. EGP inspection tools accompanied the MFL and TFI tool runs in all 11 segments. 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 19 in Section 8 on Integration of Intervention Requirements.

3.6. Stress-Corrosion Cracking

SCC has not been identified as a threat to the Longhorn pipeline, but was added as SCC has been an unexpected problem for some pipelines. Since no evidence of SCC has been detected, it is not necessary to recommend an intervention measure. Magellan will continue to monitor for this threat through their current method, which consists of looking for evidence of SCC when maintenance excavations are performed.

3.7. Threats to Facilities Other than Line Pipe

The Longhorn facilities maintenance program represents a thorough and comprehensive means of facility inspection and preventive maintenance.

The LMP requires that all changes on the Longhorn system "be evaluated using an appropriate Process Hazard Analysis (PHA) methodology (HAZOP, What-if, LOPA etc.)." One PHA was conducted in 2015 for a pending project that will provide additional product in to East Houston with the potential to pump out to Speed Junction; however, it is currently not expected to impact LMP physical assets.

During 2015, 14 of the 18 incidents occurred at facilities, two of which were releases. Neither was DOT-reportable because they occurred during maintenance activities, were confined to company property, cleaned up promptly and were less than five barrels. Most of the facility incidents involved human error, three of which involved incorrect valve lineups to station tanks leading to line overpressure and system shutdown.

From the standpoint of facility data acquired for 2015, one can conclude that active non-pipe facilities had no adverse impact on public safety. Although these incidents had no adverse impact on public safety, Kiefner recommends that Magellan continue its detailed documentation of incidents, facility integrity processes, and reporting of the facility preventive maintenance program.

4. IMPLEMENTATION OF NEW MECHANICAL INTEGRITY TECHNOLOGIES

During 2013, T. D. Williamson (TDW) 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 TDW 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 TDW.

When material documentation is not available, Magellan has committed to conducting non-destructive or destructive strength tests for 50% of all annual pipe excavations associated with in-line inspection anomaly evaluations or remediation. In 2015, 11 excavations addressed 18 ILI anomalies between East Houston and Crane. One of the anomaly investigation sites required strength testing and was completed to meet this requirement.

5. ORA PROCESS IMPROVEMENTS

Reliability-Based Design Analysis

The 2014 ORA suggested that Longhorn consider using Reliability-Based Design Analysis (RBDA) in lieu of POE to calculate the probability that a corrosion feature may fail by either perforation leak or plastic collapse, often simply referred to as a leak or rupture. To determine if RBDA would provide a better risk model than POE, a comparison was done utilizing the 2014 ILI data from Satsuma to East Houston. TDW's HR-MFL ILI tool, SpirAll™, was used for the ILI Assessment.

RBDA and POE calculations are two different approaches to calculate a corrosion feature's probabilistic integrity threat. Longhorn currently uses POE to establish the probability that the parameters associated with a corrosion feature will cause it to exceed the criterion that could cause the feature to fail by either leak or rupture. POE assumes there is only a potential ILI depth error when calculating uncertainty of exceeding a safe threshold for failures due to either leak or rupture. 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, and model error for leaks and ruptures.

A POE analysis was performed utilizing a CGR of 5mpy for external metal loss and 1mpy for internal metal loss over a 15-year range to simulate the potential growth over the next three reassessment intervals. The metal loss features that had a POE value less than 10^{-7} at the next reassessment interval were removed from further analysis with RBDA. This left only 34 metal loss features for which a POF was calculated using RBDA.

The distributions of each input parameter were assumed or generated from existing industry reports or sources. The CGR parameter was assumed to be a constant 5mpy for external metal loss and 1mpy for internal metal loss to show a more direct comparison with the POE results. With these distributions and parameters well defined, RBDA was implemented using a Monte Carlo simulation for each year of growth over a 15-year range. In the analysis, 10^8 iterations were conducted for each of the 34 metal loss features for each year in the 15-year range. For each feature, the POF due to rupture was considered when actual burst pressure is less than the maximum allowable surge pressure (MASP) or 1.1 times MOP; while the POF due to leak was considered when the actual anomaly depth is greater than 80% WT. The burst pressures were assessed utilizing the Modified B31G method because it is the assessment used in the POE analysis and is an assessment method used by Magellan. The distributions for all parameters used in the Monte Carlo simulations for Satsuma to East Houston are listed in Table 3.

Table 3. Probability Density Functions Used in RBDA Calculations

Variable	Function Type	Function Parameters	Source
ILI Feature Depth	Normal	μ=indicated %wt, σ=7.8%wt	ILI Specification
ILI Feature Length	Normal	μ=indicated length, σ=0.62-inch	ILI Specification
Diameter	Normal	μ=1.0*OD, σ=0.06*OD	Zimmerman et al. (1998) [1]
Wall Thickness for 0.312-inch	Normal	μ=1.01*NWT, σ=0.0101*NWT	Zimmerman et al. (1998) [1]
Flow Stress for Grade B	Normal	μ=58,619 psi, σ=7240 psi	Kiefner Database
Flow Stress for Grade X52	Normal	μ=69,066 psi, σ=5828 psi	Kiefner Database
Modified B31G Model Error	Gamma	α=2.175, β=0.225, shift=0.914	GL Report [2]

*Note: For the normal distributions, μ is average and σ is standard deviation; for the Gamma distribution, α is the shape parameter, β is the scale parameter.

The results of RBDA are listed below for probability of rupture (actual burst pressure < MASP) and probability of leak (actual flaw depth > 80%wt) at the time of the next reassessment:

- The results of the Monte Carlo simulation with 10^8 iterations on Satsuma to East Houston are shown in Table 4.
  - There are four anomalies located at 89518.96, 97520.64, 97522.53, and 97524.40 ft that have a rupture probability greater than 10^{-5}.
  - There are three anomalies located at 2537.53, 97522.53, and 144098.60 ft that have leak probabilities greater than 10^{-5}.
- The results of traditional POE analysis on Satsuma to East Houston are shown in Table 4.
  - There was one anomaly located at 97522.53 ft that has a rupture probability greater than 10^{-5}.
  - There are four anomalies located at 2537.53, 48249.75, 97522.53, and 144098.60 ft that have leak probabilities greater than 10^{-5}.

RBDA could be improved if more information on the pipeline and ILI tool run is obtained for the Longhorn system. This would include more information on the pipe properties such as mill test reports (MTR) and how well the tool performed in field investigations.

Table 4. Results of RBDA and POE Analysis at Next Reassessment Interval

Absolute Distance (ft)	Depth (% WT)	Length (in)	POE (Leak)	POE (Rupture)	RBDA (Leak)	RBDA (Rupture)
97522.53	47	3.74	6.911E-04	1.046E-04	6.762E-04	5.697E-05
144098.60	46	0.94	4.399E-04	3.179E-25	5.679E-04	0
2537.53	39	1.17	1.209E-05	2.950E-12	1.150E-05	3.670E-06
48249.75	39	0.73	1.209E-05	3.745E-13	8.710E-06	2.210E-06
45925.29	38	1.15	6.796E-06	2.359E-12	4.730E-06	2.850E-06
11207.00	37	1.14	3.761E-06	2.004E-12	1.900E-06	3.360E-06
12178.93	37	2.33	3.761E-06	1.389E-09	2.570E-06	9.040E-06
13395.00	37	3.32	3.761E-06	1.650E-07	2.650E-06	8.750E-06
15361.62	37	0.56	3.761E-06	1.936E-13	2.770E-06	1.880E-06
21940.73	37	0.85	3.761E-06	5.377E-13	1.510E-06	1.840E-06
54302.30	37	0.75	3.761E-06	3.640E-13	1.540E-06	1.870E-06
9949.88	36	0.51	2.049E-06	1.643E-13	2.200E-07	1.400E-06
50019.36	36	0.69	2.049E-06	2.807E-13	2.700E-07	2.620E-06
143000.90	36	0.49	2.049E-06	2.479E-26	2.400E-07	0
143001.10	36	0.46	2.049E-06	2.299E-26	2.000E-07	0
6587.17	35	0.86	1.099E-06	4.914E-13	0	1.840E-06
26601.68	35	0.45	1.099E-06	1.392E-13	0	1.430E-06
79522.89	35	0.60	1.099E-06	2.042E-13	0	2.030E-06
131619.09	35	1.02	1.099E-06	9.445E-13	0	4.720E-06
144107.17	35	1.15	1.099E-06	3.040E-25	0	0
8913.48	34	0.68	5.800E-07	2.500E-13	0	1.160E-06
15280.65	34	0.71	5.800E-07	2.747E-13	0	1.800E-06
42692.41	34	0.69	5.800E-07	2.579E-13	0	1.940E-06
66952.20	34	0.99	5.800E-07	7.659E-13	0	5.170E-06
87330.25	34	0.72	5.800E-07	2.837E-13	0	2.790E-06
5292.41	33	0.61	3.013E-07	1.969E-13	0	9.100E-07
7149.80	32	0.69	1.541E-07	2.380E-13	0	1.780E-06
9651.06	32	0.79	1.541E-07	3.234E-13	0	9.200E-07
15033.25	32	0.67	1.541E-07	2.247E-13	0	1.780E-06
65220.26	32	0.65	1.541E-07	2.125E-13	0	1.610E-06
65313.51	32	0.93	1.541E-07	5.237E-13	0	1.170E-06
89518.96	32	3.08	1.541E-07	8.120E-09	0	4.377E-05
97520.64	32	3.54	1.541E-07	4.508E-08	0	6.504E-05
97524.40	25	5.29	9.030E-10	1.340E-07	0	4.830E-05

6. RESULTS AND DISCUSSION OF DATA ANALYSIS

This section presents an analysis of the data collected in Appendix B 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, SCC, and threats to facilities other than line pipe.

In 2015 ILI assessments were performed between the Satsuma (MP 34.1) and Crane (MP 457.5) pump stations. Two different ILI assessments were performed over this segment; MFL technology was used from Satsuma to Eckert (MP 227.9) and TFI technology was used from Satsuma to Crane. A deformation tool accompanied the MFL tool runs and the TFI tool runs between Eckert and Crane. Table 5 lists the 2015 ILI assessments by pipeline segment. Note: The TFI assessments completed in December of 2015 on the pipeline segments between Satsuma to Eckert will have their assessments completed in 2016.

Table 5. 2015 ILI Assessments

Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley	Cedar Valley to Eckert	Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
34.1 to 68.0	**68.0 to 112.9**	**112.9 to 141.8**	**141.8 to 181.6**	**181.6 to 227.9**	**227.9 to 260.2**	**260.2 to 295.2**	**295.2 to 344.3**	**344.3 to 373.4**	**373.4 to 416.6**	**416.6 to 457.5**
Corrosion										
MFL	MFL	MFL	MFL	MFL	TFI	TFI	TFI	TFI	TFI	TFI
18-Dec-14	16-Dec-14	11-Jan-15	10-Jan-15	27-Mar-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
Pressure Cycle Induced Fatigue										
TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
Laminations & Hydrogen Blisters										
No inspections for laminations and hydrogen blisters occurred in 2015.										
Third-Party Damage										
Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.
18-Dec-14	16-Dec-14	11-Jan-15	10-Jan-15	27-Mar-15	6-Aug-15	4-Aug-15	31-Jul-15	25-Jul-15	19-Jul-15	18-Jun-15

6.1. 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 (electric-flash weld) 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, East Houston to Speed Junction, 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 East Houston to Eckert Station completed in 2007 and the TFI tool run from Eckert to Crane completed in 2015.

The failure pressure of each potential 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 have 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 hydrostatic test.

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. A value of 15 ft-lbs was used in the calculations.

To conduct a pressure-cycle analysis for the Longhorn Pipeline, the well-known and widely accepted "Paris Law" model was used, 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, 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 were used. 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 are provided to Kiefner by Magellan. A systematic cycle-counting procedure called “rainflow counting” to pair maximum and minimum pressures was used. The rainflow-counted cycles are used in the Paris-Law model to grow a potential crack. For a given set of cycles, 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 can be predicted. We will notify Magellan of the calculated date of failure, and in accordance with the LMP, Magellan will complete reassessment of the integrity of the pipeline as required.

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 2007 and 2008 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. The 2015 TFI tool run indicated 13 Seam Weld B features in the Cartman to Kimble, Kimble to James, Texon to Barnhart, and Crane to Texon segments. These 13 features will be investigated in the 2016 dig program. The fatigue lives for these 13 anomalies were calculated. Pursuant to the procedure in Section 3.4 of the ORA Process Manual, the detection threshold capabilities of the TFI tool was used to calculate an appropriate reassessment for anomalies that have not been detected by the TFI tool. The TFI can detect seam weld features with a depth of 50% of the wall thickness for features between one and two inches in length and a minimum depth of 25% of the wall thickness for features greater than two inches in length.

Based on these detection capabilities, the analysis assumes that a 50% through wall, 2-inch long crack-like feature could have been missed. The 50% through wall flaw has a shorter life than a 25% through wall flaw. In the Existing Pipe, it was assumed the flaw could have been missed in a location that will provide the most conservative reassessment interval. The pipe located closest to the discharge of a pump or right at a wall thickness or pipe grade transition was chosen 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, a starting flaw size that is the largest flaw that could have escaped detection in the manufacturer's ultrasonic seam inspection was used. 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% of the nominal wall thickness of the pipe. That flaw is used as the starting defect size in the 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 2015. The analysis was completed in three sets to reflect the configurations of the pipeline during the 2007-2015 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 2015 data, in which the line was operating in its fully reconfigured format and all pumps were in operation. For line segments which were inspected by TFI in 2014 or 2015, only pressure data after the ILI was completed were used in the analysis.

The analysis showed that the shortest time to failure for a possible feature that could have been missed by the 2007-2008 TFI tool run is 14.7 years (from November 1, 2013) at the location that is now the Bastrop Station Discharge. The recommended reassessment interval is calculated by taking 45% of the shortest fatigue life, which corresponds to a factor of safety of 2.22 (1/0.45). Applying this factor of safety, a reassessment interval of 6.6 years (from November 1, 2013) is recommended based on the current operating pressures. An assessment would be required in 2020 for the Warda to Bastrop and Buckhorn to Warda segments. For all thirteen TFI-detected Seam Weld B features found during the 2015 TFI, the calculated fatigue life is greater than for a tool detection threshold sized anomaly at the worst-case location in the respective segments. Therefore, the detection threshold anomalies determine the appropriate reassessment intervals. Assessments for the other segments would be required between 2023 and 2238, as stated in Section 3.1. The pressure cycling frequency decreased in 2015 for all segments except the Satsuma to East Houston segment, when compared to 2014 which resulted in a longer time until reassessment for segments which were not reassessed in 2015. Figure 5 displays the pressure cycles at the Bastrop Station discharge during 2015. Figure 6 displays the pressure cycles at the Bastrop Station discharge during 2014. These figures are representative of pressure cycling in the Crane to Satsuma segments.

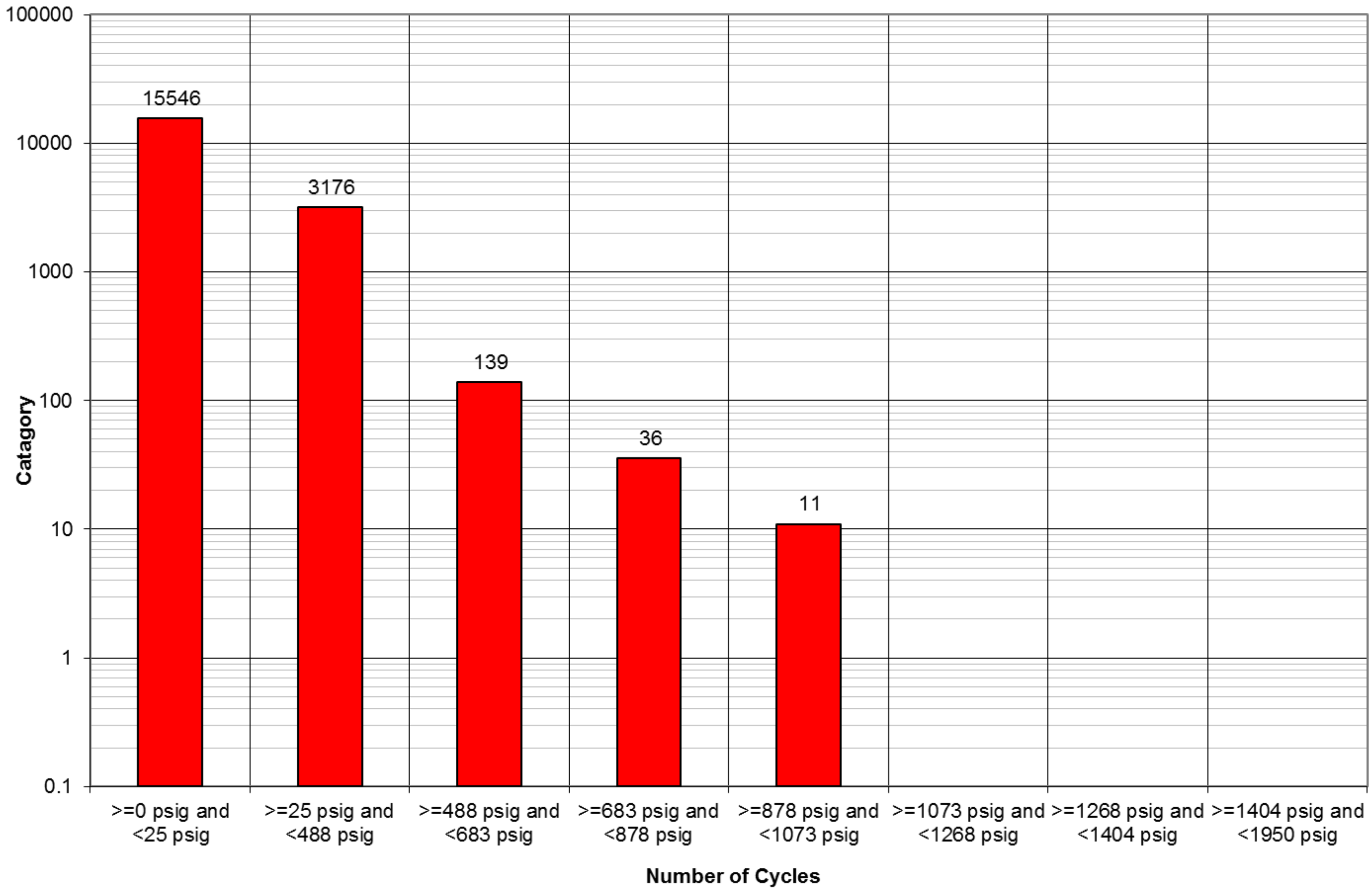

Figure 5. Pressure Cycles at Bastrop Station in 2015

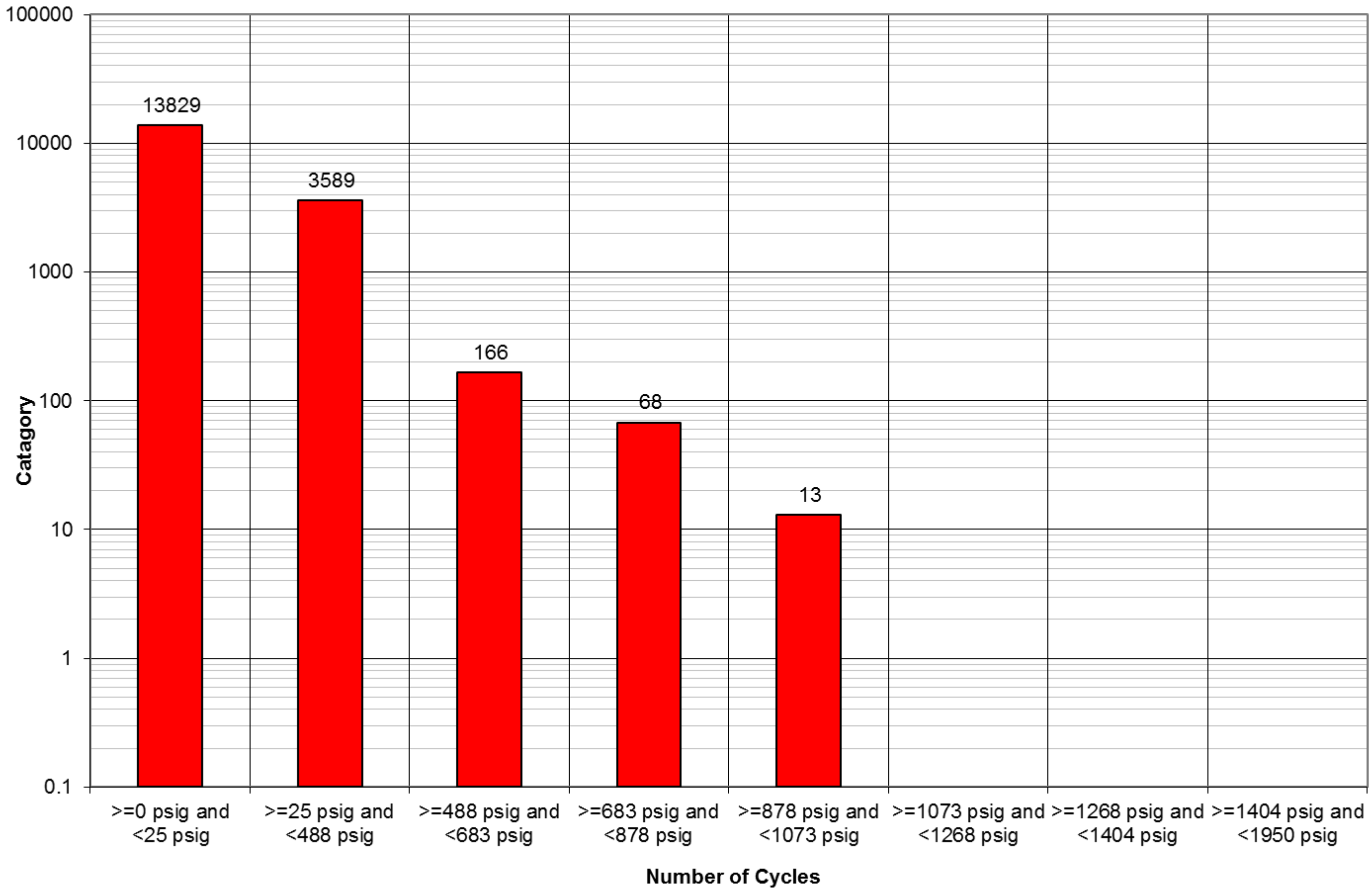

Figure 6. Pressure Cycles at Bastrop Station in 2014

Table 6 summarizes the locations evaluated. For the piping between Eckert Station and Crane Station, 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 1, 2013 through December 1, 2015 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 7 for the piping between Eckert Station and Crane Station are to be taken from November 1, 2013. For the piping between East Houston Station and Satsuma Station, the pressure data recorded after each segment's TFI ILI date were used in the analysis. The factor of safety should be applied to these fatigue lives to determine the reassessment interval. As the Crane to El Paso products and East Houston to Speed Junction crude segments of the line operate separately from the Crane to East Houston segment, results for these segments may be considered separately. A fatigue life was calculated for the new 1998 pipe at Crane Station on the products line and on 1998 pipe in the East Houston to Speed Junction segment based on the maximum flaw size, described above as an API 5L N10 notch, a 10%, 2-inch-long flaw. The analysis showed that the shortest time to failure for the Crane to El Paso segment is greater than 500 years. This would result in a reassessment interval of a minimum of 225 years. The shortest time to failure for the East Houston to Speed Junction segment is 480.7 years. This would result in a reassessment interval of a minimum of 216.5 years.

Table 7 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% deep and 2-inches long, and no feature greater than 10% of the wall thickness existing in the new pipe and the factor of safety of 2.22.

Table 6. 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	45,000 SMYS
3	1950 Pipe near Warda Discharge	EFW	A.O. SMITH	5960+75	112.9	18	0.281	45,000 SMYS
4	1950 Pipe near Bastrop Discharge	EFW	A.O. SMITH	7487+53	141.8	18	0.281	45,000 SMYS
5	1950 Pipe near Cedar Valley Discharge	EFW	A.O. SMITH	8402+75	159.1	18	0.312	45,000 SMYS
6	1950 Pipe near Eckert Discharge	EFW	A.O. SMITH	12032+98	227.9	18	0.281	45,000 SMYS
7	1950 Pipe near James River Discharge	EFW	A.O. SMITH	13736+94	260.2	18	0.281	45,000 SMYS
8	1950 Pipe near Kimble Discharge	EFW	A.O. SMITH	15585+45	295.2	18	0.281	45,000 SMYS
9	1950 Pipe near Cartman Discharge	EFW	A.O. SMITH	18212+02	344.9	18	0.281	45,000 SMYS
10	1950 Pipe near Barnhart Discharge	EFW	A.O. SMITH	19354+32	366.6	18	0.312	45,000 SMYS
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	45,000 SMYS
15	1998 in East Houston to Speed Junction	ERW-HF	U.S. STEEL	187+87	3.6	20	0.312	X52

Table 7. Fatigue Lives and Reassessment Intervals for Analysis Locations

Case	Cycles per Year	Date of Previous Assessment	Calculated Time to Failure from reversal date or 2015 TFI run date, years	Reassessment Interval, years	Reassessment Year
1	5,707	10/1/2014	28.8	13.0	2027
2	3,468	12/20/2007	32.5	14.6	2028
3	3,376	12/20/2007	15.9	7.2	2020
4	5,699	9/19/2007	14.7	6.6	2020
5	1,482	9/19/2007	131.9	59.4	2073
6	3,071	3/22/2007	21.7	9.8	2023
7	3,173	8/19/2015	26.4	11.9	2027
8	2,750	9/1/2015	42.4	19.1	2034
9	2,909	8/28/2015	20.5	9.2	2024
10	2,394	8/24/2015	85.1	38.3	2053
11	2,478	8/11/2015	20.2	9.1	2024
12	2,281	7/17/2015	17.3	7.8	2023
13	429	N/A	500.0	225.2	2238
14	1,609	9/19/2007	56.3	25.4	2039
15	823	N/A	480.7	216.5	2214

6.2. Corrosion

Metal Loss Features

ILI assessments 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. This generally accepted method is a valid approach for addressing line pipe corrosion.

In 2015, MFL assessments were completed from Eckert to Satsuma and TFI ILI assessments were completed from Crane to Satsuma. A deformation tool accompanied the MFL tool runs and the TFI tool runs between Eckert and Crane. Table 5 lists by pipeline segment, the 2015 ILI assessments; mile posts are noted under each pipeline segment. Magellan will be performing validation digs on the 2015 MFL and TFI runs in 2016.

A run-to-run comparison was done to determine external CGRs for the MFL assessments. The correlation of MFL assessments (2006/2007 to 2015) resulted in 3,710 external data pairs. External CGRs were calculated for all segments from Eckert to Satsuma and are shown in Table 8. The observed upper bound corrosion growth rate between Satsuma to Eckert ranged from 3.7 mpy to 6.0 mpy. These corrosion growth rates are in the range of the 5.0 mpy rate found in previous external CGR study performed in 2011. Data correlation and calculations were done using Kiefner's CorroSure software.

Table 8. External CGR Results for MFL Assessments

Segment	Inspection Technology	External Upper Bound CGR (mpy)
Eckert to Cedar Valley	MFL	5.1
Cedar Valley to Bastrop	MFL	4.9
Bastrop to Warda	MFL	4.4
Warda to Buckhorn	MFL	6.0
Buckhorn to Satsuma	MFL	5.6
Satsuma to E. Houston	MFL	3.7

The population distribution of the metal loss (ML) or metal gain (MG) used to calculate CGRs were evaluated as the population frequency histogram shown in Figure 7 for the MFL assessments. Assuming a normal distribution for the ML versus MG population the bias in the distribution mean represents either the average CGR for the entire ILI run or it may indicate an ILI error. Figure 7 shows the goodness of fit for a normal distribution for features from the 2015 MFL ILI assessments with a depth greater than 12% WT. Metal loss features with depths of 10 and 11% WT from the 2015 MFL ILI assessments were not included in the CGR analysis due to the uncertainty of the accuracy of the 2006/2007 MFL assessment depths for these features.

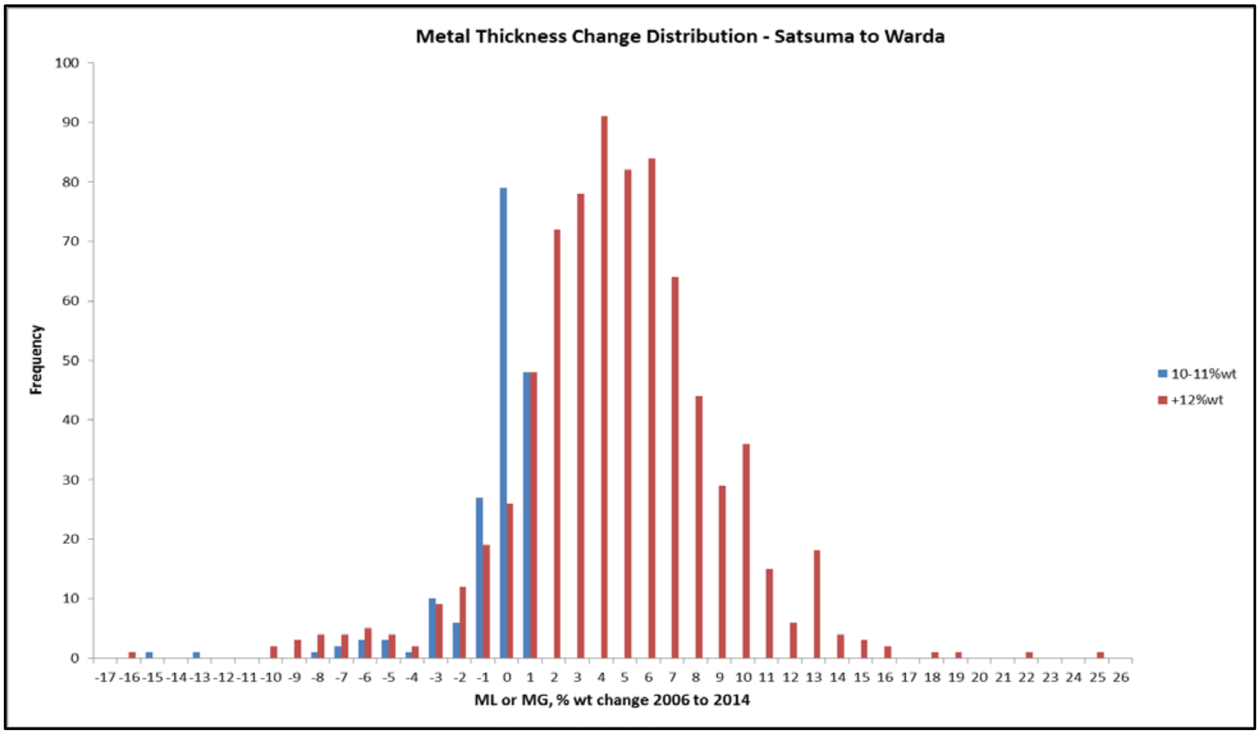

Figure 7. Histogram Showing the Distribution of Metal Loss/Metal Gain Obtained from the 2006 to 2015 MFL Assessment Comparison (3710 Data Points)

External CGRs 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 external metal loss features are more likely. A comparison of external metal loss frequency histograms for the 2006/2007 MFL and TFI assessments and the 2015 MFL and TFI assessments can be seen in Figure 8 for Crane to Satsuma. Note that a couple of possible explanations for the increase of metal loss features in 2015 could be due to advancements in tool technology or could be low level metal loss features that were just below the 10%wt threshold in 2006/2007 and are now just above the 10% WT threshold in 2015.

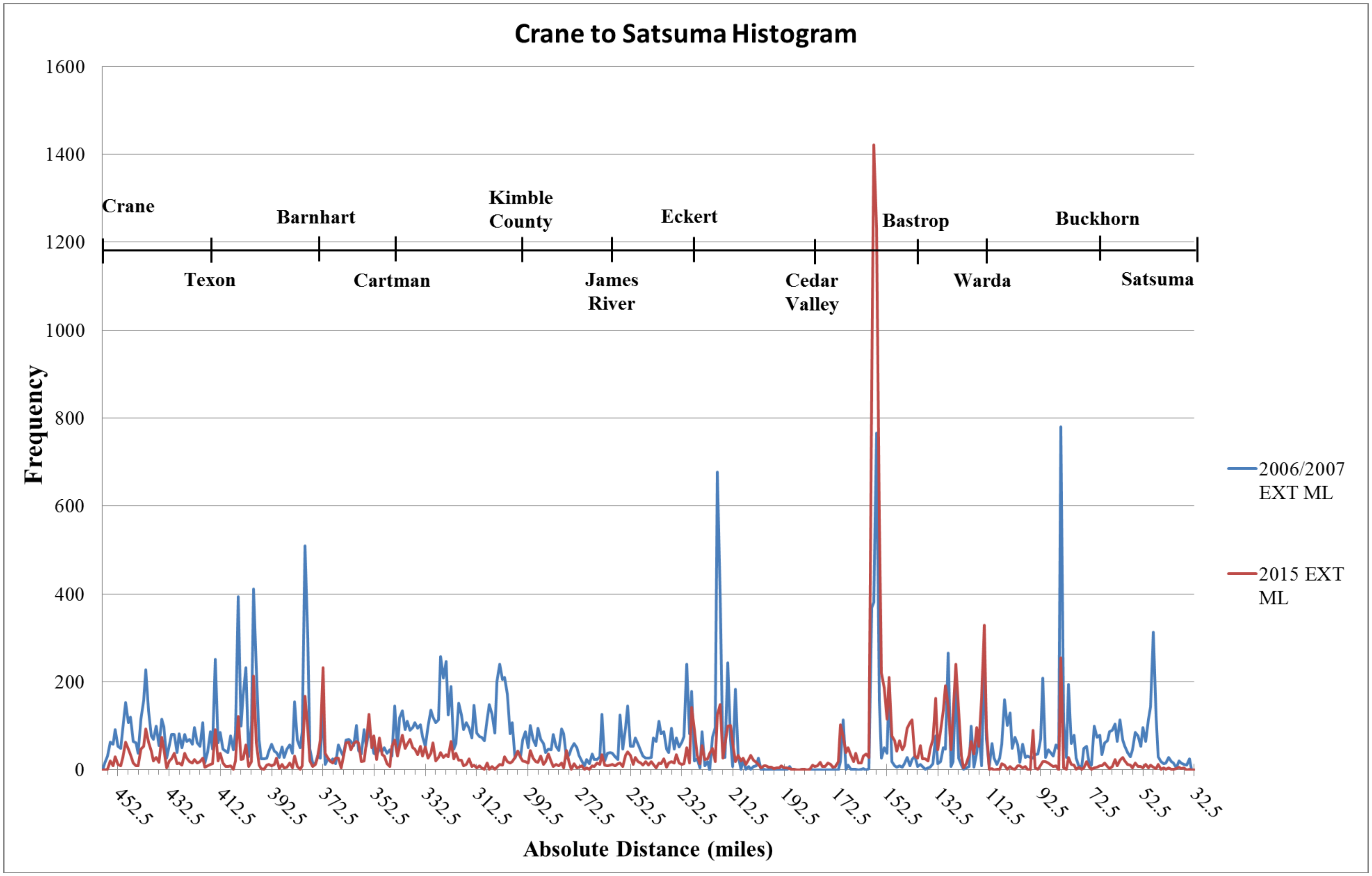

Figure 8. Crane to Satsuma External Metal Loss Frequency by Linear Distance along the Pipeline (2006/2007 MFL vs 2015 MFL Data)

Seam Weld Features

The TFI assessments were also correlated and resulted in 4,084 external data pairs. A CGR for the metal loss features was not calculated using the TFI inspections due to the large range in tool performance +/-15% WT. The TFI seam weld features were correlated and the results are shown in Table 9. Possible explanations for the difference in reported seam weld anomalies between 2007 and 2015 could be due to changes in tool technology, how features were reported, removal of 2007 reported seam weld anomalies, and debris being reported in the pipeline. GE reports that debris was present throughout the pipeline segment between Crane and Eckert. GE states that in areas where debris is located the capability to detect small features is reduced and could affect ID/OD discrimination.

Table 9. Correlated Seam Weld Anomalies from TFI Assessments

Segment	2015 Seam Weld Anomalies	2007 Seam Weld Anomalies	Correlated Seam Weld Anomalies	Percentage Matched (%)
Crane to Texon	214	1396	189	88
Texon to Barnhart	100	1049	72	72
Barnhart to Cartman	188	178	48	26
Cartman to Kimble County	95	687	53	56
Kimble County to James River	310	195	51	26
James River to Eckert	63	317	38	60

ID Reductions/Geometric Anomalies

The ILI runs from Satsuma to Crane identified 1,083 geometric anomalies, 70 of which were repaired as of the end of 2015. Of the 1,013 remaining anomalies, 560 are located on the bottom of the pipeline with depths that range from 0.27% to 4.2%; 473 are located on the top of the pipe with depths that range from 0.2% to 3.42%.

Table 10 provides a summary of geometric anomalies affecting seam welds, girth welds, and anomalies with metal loss. Geometric anomalies affecting seam welds were found from Crane to Eckert, with a total of 292 occurrences. Nineteen anomalies affecting girth welds and 17 associated with metal loss were found within this area of the pipeline.

Table 10. Geometric Anomalies Associated with Seam Welds, Girth Welds and Metal Loss

Segment	Affecting Seam Weld	Affecting Girth Weld	With Associated Metal Loss
1-Buckhorn to Satsuma	0	0	0
2-Warda to Buckhorn	0	0	0
3-Bastrop to Warda	0	0	0
4-Cedar Valley to Bastrop	0	0	0
5-Eckert to Cedar Valley	0	0	0
6-James River to Eckert	75	0	5
7-Kimble to James River	38	3	3
8-Cartman to Kimble	71	8	1*
9-Barnhart to Cartman	58	3	4
10-Texon to Barnhart	8	0	3
11-Crane to Texon	42	5	1
Total	**292**	**19**	**17**

*Upon further review by Magellan this geometric anomaly was found not to have metal loss.

The Longhorn Pipeline System travels through a number of HCAs from James River to East Houston. As shown in Table 11, 97 of the geometric anomalies are located within HCAs; however, most do not meet the current regulatory repair criteria as many are either less than the 2% depth, or on the bottom of the pipe and less than 6% depth.

Seventeen geometric anomalies associated with metal loss were found. Two are located on the top of the pipe with depths of 0.61% and 0.93% – both within the James River to Eckert segment – but not within an HCA. The rest of the metal loss anomalies are located on the bottom of the pipe with depths ranging from 0.4% to 3.52%. Only one of these is located within an HCA (between James River and Eckert) with a depth of 2.46% on the bottom of the pipe which falls under the 60-day period for evaluation and remediation required by 49 CFR 195.452(h)(ii)(B). Repairs are to be completed in January 2016.

Table 11. Geometric Anomalies Located within HCAs[3]

Segment	Within HCA		
	Anom.	**Peak Depth**	**Comment**
1-Buckhorn to Satsuma	1	2.3%	• Dent - 0.4 inch - repaired by sleeve
2-Warda to Buckhorn	3	2%, 2%, 2.1%	• All 3 on bottom of pipe (<6%)
3-Bastrop to Warda	3	2.1% to 2.3%	• All 3 on bottom of pipe (<6%); 1 already repaired by sleeve
4-Cedar Valley to Bastrop	0		
5-Eckert to Cedar Valley	29	2% to 3.4%	• 7 of the 29 repaired by sleeve • Remaining 22 dents on bottom of pipe (<6%)
6-James River to Eckert	61	.5% to 3.1%	• 4 repaired by sleeve • 15 are on the top of the pipe, with depths 1% to 1.6% (less than 2%) • 28 are on the bottom of the pipe, with depths from 1% to 3.1% (less than 6%) • 13 of the 61 affect the seam weld, with depths from 0.5% to 1.7% (less than 2%) • 1 involves metal loss (depth 2.5%) on bottom of pipe
7-Kimble to James River	0		
8-Cartman to Kimble	0		
9-Barnhart to Cartman	0		
10-Texon to Barnhart	0		
11-Crane to Texon	0		
Total	**97**		

Of the 292 anomalies affecting seam welds (Crane to Eckert), only two have depths above 2% of the nominal pipe diameter (18-inch). One is located in the Crane to Texon segment (2.2%); the other is located in the James River to Eckert segment (2.7%); neither is within an HCA. There are 13 anomalies within an HCA that affect the seam weld. They are located within the James River to Eckert segment with depths from 0.5% to 1.7%. These would not require assessment per the LMP and DOT (49 CFR 195.452(h)). It is worth noting that different technologies were used – MFL from Satsuma to Eckert and TFI from Satsuma to Crane.

[3] Dents are defined as geometric anomalies with an ID reduction greater than or equal to 2% of pipe diameter.

Tool Performance and In-Ditch Investigations

The ILI assessments were looked at with an understanding of the background and approach for API 1163 ILI verification. API 1163 Second Edition, April 2013 describes methods in Section 7 and Section 8 that can be applied to verify that the ILI tool was performing as expected and reported inspection results are within the performance specification for the pipeline being inspected.

Within the API 1163 Standard, a distinction is made between results with and without field verification measurements. For the 2015 ILI assessments a Level 1 validation was performed and consisted of the following steps:

1. A process verification or quality control Level 1 (§8.2.2 and Annex C.1)
2. Comparison with historic data for the pipeline being inspected (§8.2.3)
3. Comparison analysis of pipeline component records (§8.2.4)

Depending upon the analysis of the data using the API 1163 decision chart process, the tool performance can be rejected, accepted, or inconclusive. A Level 2 and Level 3 validation required comparison with field excavation results if warranted by the reporting of significant indications. If tool performance is determined to be non-conclusive it does not mean the inspection failed. Instead an additional course of action may be required.

An API 1163 Level 1 Validation was performed for each assessment listed in Table 5. The general results for all of the 2015 ILI assessments was that the functionality of the ILI tool was determined to be within normal standard operating conditions and the locating of reference points by the ILI tool was determined to be consistent over the entirety of the ILI assessment. A couple of items to note from the ILI assessment reports:

1. The Calscan tool did not rotate correctly throughout the inspections on the Barnhart to Cartman, Cartman to Kimble, and Kimble to James River segments; data were correlated with the TranScan to avoid orientation offset from poor rotation; and
2. Channel 9 on the geometry tool from Kimble to James River was noisy throughout the run; detection and sizing of small features affected by this issue may be degraded. Note: GE does not list any features as being affected.

In 2015, Magellan performed 10 in-ditch assessments associated with ILI anomaly investigations; of which nine corresponded to 2015 ILI assessments. Material identification testing was completed at one of the investigation locations. Table 12 shows, per pipeline segment, the quantity of anomalies that were remediated in 2015. Table 13 gives a breakdown of the dig results.

Table 12. Summary of Anomalies Remediated in 2015

Pipeline Segment	Anomalies Excavated
8-in El Paso to Chevron	0
12-in El Paso to Kinder Morgan	0
8-in Crane to Odessa	0
18-in El Paso to Cottonwood	0
18-in Cottonwood to Crane	1
18-in Crane to Texon	1
18-in Texon to Barnhart	0
18-in Barnhart to Cartman	0
18-in Cartman to Kimble County	0
18-in Kimble County to James River	0
18-in James River to Eckert	3
18-in Eckert to Cedar Valley	0
18-in Cedar Valley to Bastrop	1
18-in Bastrop to Warda	0
18-in Warda to Buckhorn	1
18-in Buckhorn to Satsuma	0
20-in Satsuma to E. Houston	7
20-in E. Houston to Speed Junction	0

Table 13. 2015 ILI Field Investigation Dig Results

Maintenance Report #	Mile Post	Pipeline Segment	Reason for Investigation	Results of Investigation	Repair Date	Girth Weld	Predicted Depth	Actual Depth	Predicted Length (in)	Actual Length (in)
2015-002	453.99	Crane to Texon	Investigate Geometric Anomaly w/Metal Loss	Found geometric anomaly with metal loss and a gouge in a ID reduction. Installed Type B Sleeve	10-06-2015	3760	0.69%OD	0.70%OD	2.48	3.60
							40%wt	38%wt (gouge)	2.00	1.32
2015-003	244.43	James River to Eckert	Pipeline Maintenance Dig	Geometric anomaly associated with metal loss and affecting seam weld. Installed Type B Sleeve	9-19-2015	21430	0.93%OD	1.12%OD	10.63	20.64
							0.61%OD	1.03%OD	4.61	20.64
							20%wt	21%wt	2.64	13.92
2015-004	141.78	Cedar Valley to Bastrop	Pipeline Maintenance Dig	Found geometric anomaly with metal loss. Installed Type B Sleeve	9-10-2015	51940	1.60%OD	1.00%OD	14.26	17.40
							17%wt	22%wt	2.90	3.84
							12%wt	20%wt	0.59	6.96
2015-005	76.21	Warda to Buckhorn	Investigate Geometric Anomaly w/Metal Loss	Found geometric anomaly with gouge. Installed Type B Sleeve	2-15-2015	50210	0.80%OD	1.00%OD	3.19	4.20
							31%wt	38%wt	0.45	0.96
2015-006	32.96	Satsuma to E. Houston	Pipeline Maintenance Dig	Found two areas of lack of fusion (LOF). Installed 2 Type B Sleeves	4-14-2015	1710	26%wt	12.8%wt (Mid-wall LOF)	2.70	3.00
							26%wt	51%wt (ID LOF)	1.71	2.88
2015-007	26.66	Satsuma to E. Houston	Pipeline Maintenance Dig	Found geometric anomaly with metal loss. Installed Type B Sleeve	4-9-2015	9390	1.40%OD	1.40%OD	8.25	11.28
							14%wt	13%wt	0.33	0.60
2015-008	16.52	Satsuma to E. Houston	Pipeline Maintenance Dig	Found geometric anomaly crossing long seam. Installed Type B Sleeve	4-28-2015	21440	0.70%OD	0.81%OD	5.07	6.40
2015-009	16.50	Satsuma to E. Houston	Pipeline Maintenance Dig	Found geometric anomaly crossing long seam and found lack of fusion (LOF). Installed Type B Sleeve	4-30-2015	21470	0.80%OD	1.00%OD	4.12	6.20
							Not Reported	17%wt (ID LOF)	Not Reported	Not Reported
2015-010	11.52	Satsuma to E. Houston	Pipeline Maintenance Dig	Found Dent. Installed Type B Sleeve	4-18-2015	27570	2.00%OD	2.04%OD	4.48	7.30
2015-012	516.39	Crane to Cottonwood	Investigate Metal Loss	Installed Type B Sleeve	8-14-2015	63460	24%wt	11%wt	2.41	2.52

6.3. Pipe Laminations and Hydrogen Blistering

In 2013, the pipeline from 9th Street Valve to Crane was converted from refined products to crude oil service. This change could potentially lead to an increased threat of hydrogen blistering. Crude oil can contain hydrogen sulfide which can lead to the formation of hydrogen through anaerobic internal corrosion. Laminations in the pipe wall can trap hydrogen from the corrosion reaction and generate blisters. Managing internal corrosion will help mitigate this threat.

A review of the 2015 maintenance reports showed that no laminations were excavated. Deformations identified from the 2015 ILI assessments were correlated with the existing laminations found from the 2010 UT assessments. No deformations correlated with laminations.

Continued 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.

6.4. 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. No hard spot assessments were performed in 2015.

6.5. Earth Movement (Fault and Stream Crossings)

Fault Crossings

The Longhorn Pipeline System crosses several aseismic faults between Harris County (Houston area) 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 14.

Table 14. 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

*CL refers to low plasticity clay

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-three subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the vertical displacements over time is shown in Figure 9. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. Using nearly 12 years of data an attempt was made 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 0.019 in/yr (0.47 mm/yr) over 11½ years for the Akron Fault and 0.020 in/yr (0.51 mm/yr) over 11½ years for the Hockley Fault.

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 nine readings taken as shown in Figure 10. The trend lines for the Negyev and Oates faults show no movement. At the McCarty Fault, there is a significant jump of about one-half inch between the baseline reading and the first reading point; no movement was observed from the readings after that. The jump at the first reading point is very likely due to a false baseline reading.

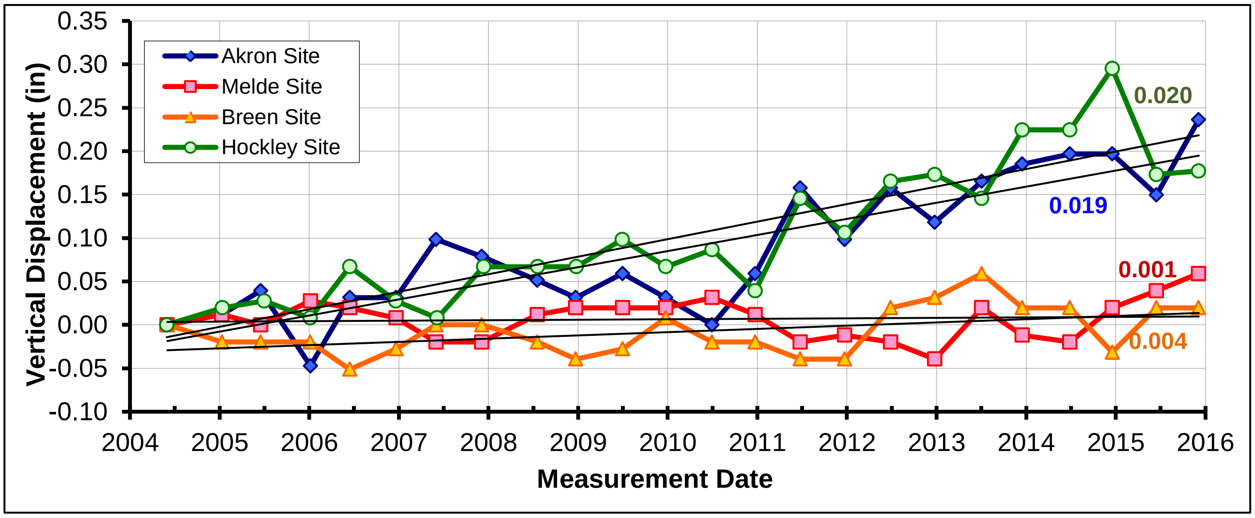

Figure 9. Fault Displacement over 12-Year Period at Akron, Melde, Breen and Hockley Faults

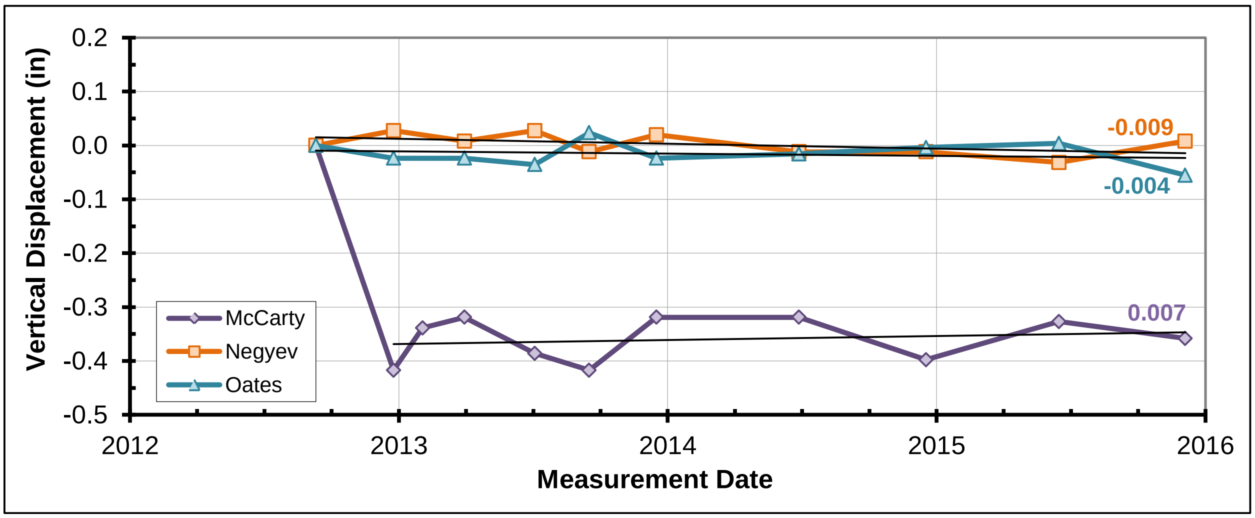

Figure 10. Fault Displacement over 3-Year Period for McCarty, Negyev and Oates

Kiefner conducted the original stress analysis to determine the maximum allowable displacements at the Akron, Melde, Breen and Hockley faults 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[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 from our best estimate for representative values of properties obtainable and the fault movement rates represented by linear trend lines fit to the data. In the 2014 ORA Annual Report, the maximum allowable displacements at the McCarty, Negyev, and Oates faults were also determined. Due to the high rate of movement and the relatively low allowable

[4] ASME B31.4-2002. The standard allows longitudinal stress up to 54% of SMYS.

displacement at the Hockley fault, the stress analysis was also repeated at this fault for the 2014 ORA Annual Report. In the 2014 analysis, the stress in the pipelines at various fault displacements were predicted through finite element analysis (FEA) with the same soil properties as used in the previous 2005 analysis. The allowable fault displacement was then determined when the stress reached the allowable stress levels in the latest ASME B31.4 at the time[5]. An important difference is that ASME B31.4 updated the allowable longitudinal stress level from 54% SMYS to 90% SMYS in 2012. The new allowable level was used to determine the critical displacement at the three faults passed by the new East Houston Line constructed in 2012. However, a lower allowable longitudinal stress as 80% SMYS was used to determine the critical displacement at the Hockley fault to compensate the potential lower quality of girth welds in the vintage 1950s Longhorn pipeline passing the fault. Please refer the 2014 ORA Report for details of the analysis.

Table 15 shows the allowable displacement at each fault, the average rate of the movement over the monitoring period, and the time to reach the allowable displacement with this rate. The allowable displacements at the Akron, Melde, and Breen faults were determined by the original 2005 analysis and those at Hockley, McCarty, Negyev and Oates faults by the 2014 analysis as described above. The average rate of movement was determined by linear regression of the recorded fault movement as shown in Figure 9 and Figure 10. The calculated rate of displacement and reduced number of years to reach the allowed displacement are similar to the values in last year's ORA Annual Report. The slight variation of values between the reports may be due to the measurement tolerance. 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 time to reach the allowable displacement at the Hockley Fault has been close to or even fallen below the life of the pipeline segment at the region which was installed in the 1950s. The pipeline life exceeded the predicted time to failure due to the following:

- The safety margin between the selected 80% SMYS allowable stress level and the actual stress level for failure,
- The fault movement history before the monitoring period is unknown, and
- Built-in conservatisms in the FEA as discussed in the 2014 ORA Annual Report.

Nevertheless, recommendations for Magellan to consider for remediating the pipeline segment at the Hockley fault location or conducting more detailed analysis have been provided in 2014 ORA Annual Report and discussed in Section 3.4 of this report. The other six faults have more than 100 years to reach the allowable displacement. Such long times to reach a displacement

[5] ASME B31.4-2012. The standard allows longitudinal stress up to 90% of SMYS.

resulting 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 is appropriate.

Table 15. Summary of Estimated Allowable Fault Displacement at Faults

	Allowable Displacement (in)	Average Rate of Movement (in/yr)	Time to Reach Allowable Displacement (yrs)
Akron	4.17	0.019	225
Melde	4.13	0.001	7,856
Breen	1.50	0.004	402
Hockley	1.25	0.020	62
McCarty	0.95	0.007	128
Negyev	2.65	0.009	294
Oates	2.65	0.004	633

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

Finally, 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 at the top four faults listed in Table 15. Actual measurements over the past 12 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. Kiefner continues to believe the time to failure is long enough that semi-annual monitoring is more frequent than necessary.

Stream Crossings

Bank Movement

There are many stream crossings on the Longhorn system, only two of which need to be inspected, one at the Colorado River crossing and the other at its tributary Pin Oak Creek. Both were surveyed twice in 2015; once in June and again in December.

As shown in Figure 11 for the Colorado River Crossing, no movement of bank locations was detected at the water crossing from the constant distance between the driveway at 7090+04 and the East High Bank at 7098+90 and the constant distance between the West High Bank at 7102+51 and the Marker Post at 7110+56. The distance between the East High Bank and the toe of the slope decreased by 11 feet in 2015. The total decrease of the distance compared to that in 2006 reached 24 feet. The distance between the West High Bank and the top of the slope increased by 5 feet in 2015. The distance between the two toes of the slope were not measured in 2015. The data indicate the river shifted slightly to the east during that time. The waterway inspection covered in a later section showed there is still considerable depth of cover left near the east bank.

As shown in Figure 12 for the Pin Oak Creek crossing, no movement of bank locations was detected from the constant distance between the Marker Post at 6470+46 and the East High Bank at 6501+99 and the constant distance between the West High Bank at 6471+28 and the Marker Post at 6471+80. The distance between East High Bank and the toe of the slope increased by one foot and the distance between the West High Bank and the toe of the slope decreased by one foot in 2015. The distance between the toes at the two slopes also increased considerably compared to the last measurement in the summer of 2013. The changes were expected due to the large amount of rainfall in 2015.

Magellan is committed to continue conducting two inspections per year at the two crossings and monitoring the depth of cover of the pipeline and scouring of the banks.

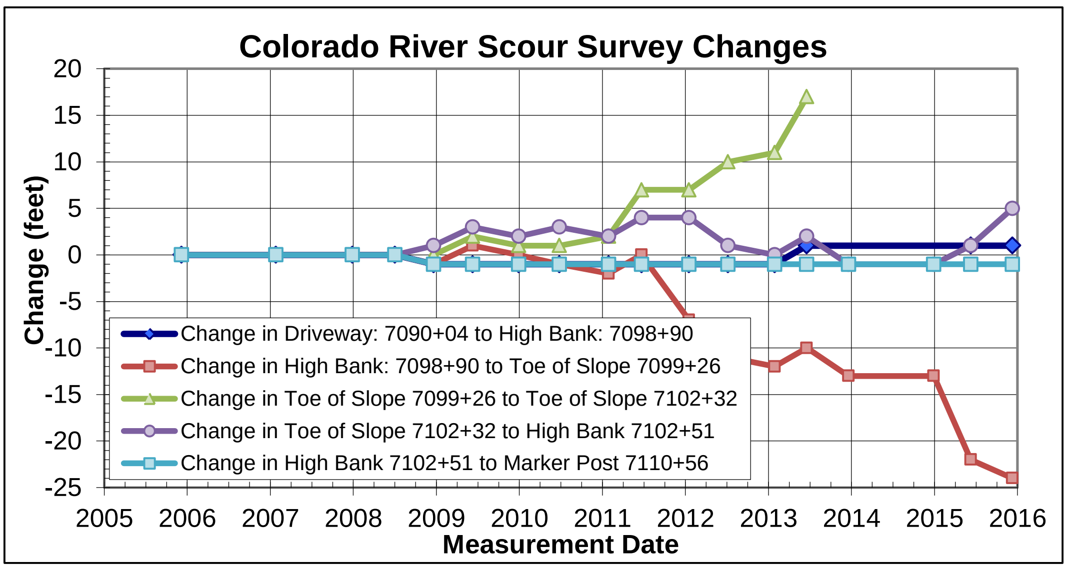

Figure 11. Changes in the Scour Survey of the Colorado River over 8 Years

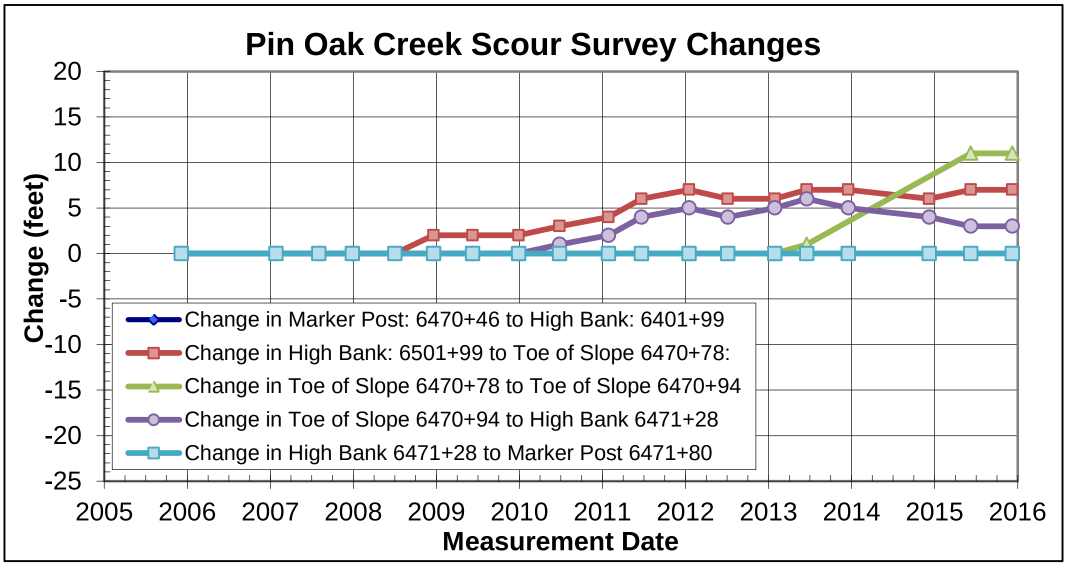

Figure 12. Changes in the Scour Survey of Pin Oak Creek over 8 Years

Waterway Inspection

The waterway crossings are required to be inspected once every five years. The depth-of-cover (DOC) of the pipe crossing the bottom of the Pin Oak Creek and Colorado River were inspected by ONYX Service Incorporated on July 6 and July 8, 2015, respectively. No pipeline exposures were found.

The inspection at the Pin Oak Creek crossing found the DOC at least five feet below the bank of the river. However, there is a 6-foot long section near the west bank of the river with a DOC less than or equal to one foot. The photo of the west bank also shows evidence of potential erosion. Close inspection and further remediation are recommended to fix the problem.

The inspection at the Colorado River crossing found the pipeline was at least six feet below the bank of the river. There is a 100-foot long pipe segment at the river bottom near the west bank that has a DOC less than two feet. Grout bag repair had been installed over this segment from the West bank to about half way across the river. There is also an 8-ft by 20-ft concrete mat placed about 15 years ago on the West bank to reduce scour at the downstream of the grout bag. In the remaining pipeline segment below river bottom without a concrete mat, the DOC is between two and four feet.

Flood Monitoring

There were two times during 2015 when the water surface exceeded the flood stage at both the Colorado River and Pin Oak Creek. The monitoring site for the Colorado River is at Bastrop and the site for Pin Oak Creek is located at Smithville. The first incident occurred between

May 26 and 27, 2015. The Colorado River exceeded the flood stage of 23 feet by 2 feet and Pin Oak Creek exceeded the flood stage of 20 feet by more than 8 feet. The second incident occurred between October 31 and November 1, 2015. The Colorado River exceeded the flood stage of 23 feet by 9 feet and the Pin Oak Creek exceeded the flood stage of 20 feet by 9 feet.

Magellan is expected to visually inspect the water crossings whenever a flood condition occurs.

Aerial Inspection (Every Five Years)

Every five years, an aerial survey of the pipeline is required to examine areas of concern (AOCs) which are high relief areas or where pipeline exposure was found. The first survey was conducted in May and June of 2000. The initial survey reported a total of 88 AOCs. The survey in June 2005, a subset of the AOCs from the survey in 2000, further identified as areas of elevated concern (AOECs) which include high relief areas and areas where the pipeline was exposed within an adjacent rocky slope. The survey in November 2010 expanded the AOECs to include areas where either the pipeline was potentially exposed or an increased likelihood of future exposure was observed. The survey in 2010 also added 13 new AOCs which did not appear to be newly eroded or changed areas but rather areas that were not previously documented.

The latest aerial survey was completed on October 27 and 28, 2015. The report was submitted to Magellan in December 2015. The survey found that four previously identified AOECs appeared to have changed; two were updated to AOECs; one new AOEC and three new AOCs were added. The new AOEC appeared to be newly eroded and three AOCs were not new but had not been documented. The report recommended that a more detailed inspection of the AOECs and areas showing exposed or potentially exposed pipeline sections be conducted.

6.6. 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 2015 TPD Annual Assessment, Kiefner concluded:

- In 2015 there were four ROW near-misses, three of which were one-call violations.
- The 2015 TPD Annual Assessment shows a decrease of approximately 37.2% in the number of aerial patrol observations.
- There was an approximate 23.6% increase in unique[6] aerial patrol observations, with a 39% increase in third-party activity or non-company aerial-patrol-observations.
- One-call frequency decreased approximately 14.4% and the number of tickets sent to Field Operations for clearing/locating decreased by approximately 19.3%.
- There was no ILI detected third-party damage.

[6] Unique observations refer to first and second party

For further detail see Appendix B, Section B.11 One-Call Violations and Third-Party Damage Prevention Right-of-Way Surveillance Data.

Three new exposures were identified in 2015 and subsequently additional cover was added. One site that has been actively managed under the Outside Forces Damage Prevention Program in accordance with the System Integrity Plan (SIP) was also repaired after additional erosion was found. Additionally, six road crossings and three ditch water crossing areas were remediated along the line.

One-Call Violation Analysis

Of 16,652 one-calls in 2015, it appeared that 15% 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).

Most one-call tickets continue to occur in two counties. Harris County (Houston) accounted for 10,919 (66%) of the one-call tickets. Travis County (Austin) accounted for 1,916 (12%) of the one-call tickets. Thus, 78% of the one-call notifications on the pipeline occurred in these large metropolitan areas. Clearly, based upon those data, these two areas present the greatest potential for third-party damage. El Paso has the next highest number with 760 tickets (4%).

There were three one-call violations during 2015; all were considered ROW near-misses.

- January 2, 2015 – MP12.04: Apartment complex began excavation to repair water line near/on top of Longhorn line without one-call. The line was exposed but no damage was found. Excavation was not discovered during aerial or ground patrol but by Magellan employee.

- January 26, 2015 – MP177.2: Landowner installed two 4x4-inch posts on top of the pipeline and laid timbers across the ROW without contacting the One-Call Center. The encroachment was discovered by Magellan contractors. No damage to the pipeline was found.

- September 2, 2015 – MP113.8: Contractor did not make one-call before replacing a fence over the ROW. The encroachment was discovered by aerial patrol.

Magellan should continue to ensure all relevant data are 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 (one day per week shall be a ground-level patrol).

Magellan met this frequency requirement.

The data summarized under Item 56, Miles of Pipe Inspected by Aerial Survey by Month for 2015 showed that Magellan exceeded these requirements in terms of the total mileage patrolled.

The ORA Process Manual requires that an ILI tool capable of detecting TPD will be run in any 25-mile pipeline segment in the event that three or more one-call violations occur within a 12-month time period. Based on this requirement, no additional ILI inspections regarding TPD are required.

No additional direct examinations are recommended at this time.

6.7. Stress-Corrosion Cracking

In the 65 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 by Magellan as a supplemental examination when the pipe is exposed and examined for other reasons such as ILI anomaly excavations.

6.8. Facilities Other than Line Pipe

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 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 of tracking mechanical integrity recommendations.

Facility safety review inspections addressing items related to safety, security, and environmental compliance were completed for 15 pipeline facilities during 2015. 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. The Management of Change process requires that all changes be evaluated using an appropriate hazard analysis technique (HAZOP, what if, etc.) and that the change be assessed to ensure that the appropriate risk mitigation levels on the system are maintained.

One Process Hazard Analysis (PHA) was conducted in 2015 for a pending project that will provide additional product in to East Houston with the potential to pump to Speed Junction; however, it is currently not expected to impact LMP physical assets.

During 2015, 13 of the 18 incidents occurred at facilities, two of which were releases. The first occurred at Crane Station where a vacuum truck was used to drain-up manifold supplying tanks to install two new valves. The driver (contractor) dropped the end of the hose into the manifold pit and the hose valve leaked 40 gallons of crude oil into the concrete pit. The second incident occurred at the El Paso Terminal, which involved installing a blind flange on Tank 10. The bolts of the blind flange were not properly tightened resulting in a spill of 84 gallons of refined product. Neither was DOT-reportable because they occurred during a maintenance activity, were confined to company property, cleaned up promptly and were less than five barrels.[7]

Nine of the facility incidents involved human error, most of which were due to procedures not being followed, three of which involved incorrect valve lineups to station tanks leading to line overpressure and system shutdown.

[7] Per 49 CFR 195.5, Reporting Incidents

From the standpoint of facility data acquired for 2015, one can conclude that active non-pipe facilities had no adverse impact on public safety.

7. Overall LPSIP Performance Measures

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 (or scorecarding) 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 2015 is evaluated below.

7.1. 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 is 100% of the commitment. Magellan met this commitment in 2015.

- 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.

- <u>Number of outreach or training meetings (listed with locations and dates) to educate and train the public and third parties about pipeline safety</u>. 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.

- <u>Number of calls (sorted by Tier I, Tier II or Tier III) through the one-call system to mark or flag the Longhorn Pipeline</u>. 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 16 provides a summary of the LPSIP Activity Measures from 2005 through 2015.

Table 16. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Miles of pipelines inspected by aerial survey and by ground survey (86,310 mi required)		203,081	197,234	188,884	187,931	181,308	180,045	188,564	188,772	179,107	176,884	175,920
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	536	460	291	76	66	539	266	130
No. of outreach or training meetings to educate and train the public and third parties about pipeline safety		28	18	25	21	17	22	20	22	17	30	36
No. of calls through the one-call system to mark or flag Longhorn's pipeline	Tier I	5,402	6,509	6,622	6,791	5,277	5,277	5,757	5,757	8,637	10,268	4,302
	Tier II	6,881	7,874	7,852	7,059	4,265	4,265	4,415	4,415	6,370	7,641	9,183
	Tier III	1,498	1,617	1,653	1,459	833	833	918	918	1,312	1,554	3,167

7.2. 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 2015 are presented in Table 17.

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 conditions in recent years (2009-2014) has been zero. In 2015 there were two immediate conditions remediated for a rate of 0.004 immediate conditions per mile. The two immediate conditions were dents associated with metal loss; the dents appear to have been reported as plain dents in previous ILI runs. The 2015 immediate conditions results did not indicate a trend but should continue to be monitored and the excavation program continue to address significant reported anomalies.

POE evaluations showed 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 2015 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 reassessment tests have been performed for pipeline integrity purposes.

Table 17. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0	0	0	0	0	0	0.004
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	NA	0.0212	0.035	0.006	0	0	0	0	0	0	0
	Tier II	NA	0.0208	NA	NA	0	0	0	0	0	0	0.004
	Tier III	0.192	NA	0.003	NA	0	0	0	0	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA	NA	NA	NA*	NA**	NA**	NA**
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017	0.14	0.035	0.025	0.033	0.017	0.013~

* Hydrostatic tests were performed for pipeline commissioning purposes.
**No hydrotests were performed during 2014 and 2015.
~POE calculations were only performed on the MFL assessments; the number of POE evaluations per mile pigged did not include the TFI mileage.

7.3. 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 18. Response times, volumes, and costs are for DOT-reportable leaks.

Table 18. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Number of leaks (DOT reportable)		2	0	1	3	0	1	2	0	2	2	0
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA
	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA
Average product volume released per incident	Tier I	5.7 bbls	0	5.7 bbls	0.4 bbls	0	0.4 bbls	1.2 bbls	NA	0.47 bbls	2.74 bbls	0
	Tier II	0	0	0	0	0	0	0	NA	0	0	0
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0
Total product vol. released in the 12-month period	Tier I	17 bbls	0	5.7 bbls	1.3 bbls	0	0.4 bbls	2.5 bbls	NA	0.47 bbls	5.48 bbls	0
	Tier II	0	0	0	0	0	0	0	NA	0	0	0
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50	< $50	NA	> $100k	< $25	0
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50	< $25	NA	< $25k < $50k > $100k	< $25	0
Reports from aerial surveys or ground surveys of encroachments into the pipeline ROW without proper one-call		1	0	1	3	3	1	1	2	2	0	3
Number of known physical hits (contacts with pipeline) by third party activities		0	0	0	0	0	0	2	0	0	0	0
Number of near-misses to the pipeline by third parties		7	1	7	5	6	2	4	3	2	0	4
Number of service interruptions		115	165	155	74	16*	17	9	8	15	15	11

8. INTEGRATION OF INTERVENTION REQUIREMENTS AND RECOMMENDATIONS

8.1. 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. These 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 19 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 6.1 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 19 because it is currently addressed using surface surveys rather than ILI technology.

Table 20 presents the existing ILI runs and planned inspections for the refined system.

Table 19. Existing ILI Runs and Planned Future Inspections for Longhorn Crude System

	Speed Jct to E. Houston	E. Houston to Satsuma	Satsuma to Warda: Satsuma to Buckhorn	Satsuma to Warda: Buckhorn to Warda	Warda to Cedar Valley: Warda to Bastrop	Warda to Cedar Valley: Bastrop to Cedar Valley	Cedar Valley to Eckert	Eckert to Ft McKavett: Eckert to James River	Eckert to Ft McKavett: James River to Kimble County	Eckert to Ft McKavett: Kimble County to Cartman	Ft McKavett to Crane: Cartman to Barnhart	Ft McKavett to Crane: Barnhart to Texon	Ft McKavett to Crane: Texon to Crane
Mileage	**10.83 to 2.35**	**0 to 34.1**	**34.1 to 68.0**	**68.0 to 112.9**	**112.9 to 141.8**	**141.8 to 181.6**	**181.6 to 227.9**	**227.9 to 260.2**	**260.2 to 295.2**	**295.2 to 344.3**	**344.3 to 373.4**	**373.4 to 416.6**	**416.6 to 457.5**
Assessments													
	Corrosion												
Tool		MFL[1]											
Date of Tool Run		28-Oct-04											
Tool		MFL[2]											
Date of Tool Run		14-Dec-05											
Tool			MFL		MFL		MFL	MFL			MFL		
Date of Tool Run			21-May-06		21-Jul-06		2/15/2007	19-Dec-06			12-Oct-06		
Tool		TFI	TFI		TFI		TFI	TFI					
Date of Tool Run		6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07	9-Nov-07					
Tool											TFI		
Date of Tool Run											8-Jan-08		
Tool		UT	UT										
Date of Tool Run		22-Sep-09	24-Nov-09										
Tool					UT		UT	UT			UT		
Date of Tool Run					24-Jan-10		20-Feb-10	25-Jun-10			8-Jul-10		
Tool													
Date of Tool Run													
Tool													
Date of Tool Run													
Tool	SMFL	SMFL	MFL	MFL									
Date of Tool Run	2-Oct-14	1-Oct-14	18-Dec-14	16-Dec-14									
Tool					MFL	MFL	MFL	TFI	TFI	TFI	TFI	TFI	TFI
Date of Tool Run					11-Jan-15	10-Jan-15	27-Mar-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Pressure Cycle Induced Fatigue												
Tool		TFI ‡	TFI ‡		TFI ‡		TFI ‡	TFI ‡					
Date of Tool Run		6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07	9-Nov-07					
Tool											TFI		
Date of Tool Run											8-Jan-08		
Tool			TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
Date of Tool Run			18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Next Required Assessment												
Corrosion	2-Oct-19	18-Dec-19	18-Dec-19	16-Dec-19	11-Jan-20	10-Jan-20	27-Mar-20	19-Aug-20	1-Sep-20	29-Aug-20	24-Aug-20	11-Aug-20	17-Jul-20
Pressure-Cycle Induced Fatigue	2214	2026	2028	2020	2020	2039	2023	2027	2034	2024	2053	2024	2023

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.
‡ 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.

	Speed Jct to E. Houston	E. Houston to Satsuma	Satsuma to Warda		Warda to Cedar Valley		Cedar Valley to Eckert	Eckert to Ft McKavett			Ft McKavett to Crane		
			Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley		Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
Mileage	**10.83 to 2.35**	**0 to 34.1**	**34.1 to 68.0**	**68.0 to 112.9**	**112.9 to 141.8**	**141.8 to 181.6**	**181.6 to 227.9**	**227.9 to 260.2**	**260.2 to 295.2**	**295.2 to 344.3**	**344.3 to 373.4**	**373.4 to 416.6**	**416.6 to 457.5**
Assessments													
Laminations & Hydrogen Blisters													
Tool		UT	UT										
Date of Tool Run		22-Sep-09	24-Nov-09										
Tool					UT		UT	UT					
Date of Tool Run					24-Jan-10		20-Feb-10	25-Jun-10					
Third-Party Damage													
Tool		Def.											
Date of Tool Run		10-Jun-04											
Tool			Deformation		Deformation			Deformation			Deformation		
Date of Tool Run			21-May-06		21-Jul-06			19-Dec-06			12-Oct-06		
Tool		Def.	Deformation		Deformation		Def.				Deformation		
Date of Tool Run		5-Oct-07	15-Dec-07		16-Oct-07		15-Feb-07				21-Dec-07		
Tool								Deformation					
Date of Tool Run								23-Jan-08					
Tool		Def.	Deformation		Deformation								
Date of Tool Run		11-Sep-09	12-Oct-09		16-Dec-09								
Tool							Def.	Deformation			Deformation		
Date of Tool Run							25-Jan-10	27-Mar-10			5-Aug-10		
Tool		Def.	Deformation		Deformation		Def.	Deformation			Deformation		
Date of Tool Run		7-Jun-12	7-Jun-12		9-Jun-12		15-Jun-12	17-Jun-12			1-Jul-12		
Tool		Def.											
Date of Tool Run		22-Jun-13											
Tool	Def.	Def.											
Date of Tool Run	2-Oct-14	1-Oct-14											
Tool			Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.
Date of Tool Run			18-Dec-14	16-Dec-14	11-Jan-15	10-Jan-15	27-Mar-15	6-Aug-15	4-Aug-15	31-Jul-15	25-Jul-15	19-Jul-15	18-Jun-15
Next Required Assessment													
Laminations & Hydrogen Blisters	*Not Susceptible*	*	*	*	*	*	*	*	*	*	*	*	*
Third-Party Damage	2-Oct-17	18-Dec-17	18-Dec-17	16-Dec-17	11-Jan-18	10-Jan-18	27-Mar-18	6-Aug-18	4-Aug-18	31-Jul-18	25-Jul-18	19-Jul-18	18-Jun-18

*Per Longhorn EA section 9.3.2.3 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.

Table 20. Existing ILI Runs and Planned Future Inspections for Longhorn Refined System

		Crane to Cottonwood	Cottonwood to El Paso	Crane to Odessa	8" El Paso to Chevron	8" Kinder Morgan Flush Line	12" El Paso to Kinder Morgan
	Mileage	457.5 to 576.3	576.3 to 694.4	0 to 29.26	0 to 9.4		0 to 9.4
Assessments	**Corrosion**						
	Tool			MFL			
	Date of Tool Run			4-Nov-06			
	Tool			MFL	MFL	MFL	MFL
	Date of Tool Run			7-Mar-07	6-Mar-07	6-Mar-07	7-Mar-07
	Tool	MFL	MFL				
	Date of Tool Run	21-Nov-08	27-Mar-08				
	Tool			MFL			
	Date of Tool Run			28-Jun-11			
	Tool		MFL		MFL	MFL	MFL
	Date of Tool Run		19-May-12		23-Feb-12	21-Feb-12	22-Feb-12
	Tool	MFL					
	Date of Tool Run	19-Nov-13					
	Tool						
	Date of Tool Run						
	Pressure Cycle Induced Fatigue						
	Tool						
	Date of Tool Run						
	Lamination & Hydrogen Blisters						
	Tool						
	Date of Tool Run						
	Third-Party Damage						
	Tool			Deformation			
	Date of Tool Run			4-Nov-06			
	Tool	Deformation	Deformation	Deformation	Deformation	Deformation	Deformation
	Date of Tool Run	2-May-07	2-May-07	7-Mar-07	6-Mar-07	6-Mar-07	7-Mar-07
	Tool	Deformation	Deformation				
	Date of Tool Run	21-Nov-08	27-Mar-08				
	Tool			Deformation			
	Date of Tool Run			28-Jun-11			
	Tool		Deformation		Deformation	Deformation	Deformation
	Date of Tool Run		19-Jun-12		23-Feb-12	21-Feb-12	22-Feb-12
	Tool	Deformation					
	Date of Tool Run	19-Nov-13					
	Tool						
	Date of Tool Run						
Next Required Assessment							
	Corrosion	19-Nov-18	19-May-17	28-Jun-16	23-Feb-17	21-Feb-17	22-Feb-17
	Pressure-Cycle Induced Fatigue	2226	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*
	Laminations & Hydrogen Blisters	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*
	Third-Party Damage	21-Nov-18	19-May-17	28-Jun-16	23-Feb-17	21-Feb-17	22-Feb-17

8.2. 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 9th Street Junction 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. The Existing Pipeline upstream of Crane is often more shallow because when built there was not a 30-inch depth of burial requirement.

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 reassessment 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.

8.3. 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 or 2015.

9. SUMMARY OF RECOMMENDATIONS

The following table provides a summary of recommendations from the 2015 ORA.

Table 21. Summary of 2015 Recommendations

Topic	Recommendation	ORA Section
In-line Inspection	Kiefner recommends that Magellan conduct a review of cleaning tool results prior to ILI inspections.	2.2
	Kiefner recommends that additional digs be conducted on metal loss features in order to statistically validate the performance of the ILI tools from the 2015 ILI assessments. To statistically validate the tool performance, a minimum of five metal loss features per tool type and segment assessed is needed. Preferably the metal loss validation features are obtained from more than one dig. (Note: Magellan plans to conduct additional digs in 2016 which should allow for tool validation.)	2.2
Reliability-Based Design Analysis (RBDA)	Consider performing 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) for features that have a POE equal to or greater than 1 x-10^{-5}. Note: RBDA could be improved if more information on the pipeline and ILI tool run is obtained. This would include more information on the pipe properties like mill test reports (MTR) and how well the tool performed from field investigations.	2.1, 5
ID Reductions	One of the dents identified through ILI is located within an HCA within James River to Eckert with a depth of 2.46% on the bottom of the pipe which needs to be remediated within 60 days. The other 16 dents with metal loss should be reviewed and compared to previous data to ensure there have been no changes. Magellan plans to complete repairs in January 2016.	2.2, 6.2
Ground Movement	We continue to recommend that monitoring of faults be changed from twice a year to every 5 years because fault movements are more than an order of magnitude smaller than anticipated in the EA. The exception is Hockley Fault which is sufficiently active to raise some concern. The current six-month monitoring practice is recommended for this fault and three options for remediation include: 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 provided in the 2014 ORA, 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 that the quality of the girth welds in the exposed segment be examined at this time. Option 2: If there is an existing inertial pigging record or internal pigging is scheduled in the near future, the level of current accumulated stresses in the pipe can be estimated. It could then be used to determine an accurate value	3.4, 6.5

Topic	Recommendation	ORA Section
	of the additional fault displacement that can be accommodated by the pipe before failure. Option 3: If no inertial pigging record is available and no dig is scheduled in the near future, a literature review could be conducted to determine the fault movement history at the location since the installation of the pipeline.	
Stream Monitoring	Semi-annual scour surveys and waterway inspections of the Colorado River crossing and its tributary Pin Oak Creek should continue at the current frequency. Kiefner recommends inspection and further remediation as needed for the of the 6-foot section of the Pin Oak Creek with low depth-of-cover.	3.4
Aerial Inspection	Ensure that the recommendation to conduct a more detailed inspection of the AOECs and areas showing exposed or potentially exposed pipeline sections identified during the 5-year aerial inspection is implemented.	6.5

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

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

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.

B.1. Pipeline/Facilities Data

The Longhorn Pipeline system includes the physical pipeline, pump stations, terminals, storage tanks, and associated mechanical components.

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

Kiefner received strip maps, alignment sheets, linefill data, and process flow schematics for the mainline system. There were no new pipe replacements installed during 2015.

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. It 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. During 2014 there 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.

Kiefner received process flow schematics for the refined product transport from Odessa through Crane and to the El Paso Terminal and the crude system from Crane to the East Houston Terminal and South to 9th Street Junction. The following table provides a current list of the Longhorn pump stations, milepost numbers, tier levels, and elevations from Crane to East Houston.

There were no significant changes involving the pumping stations or terminals during 2015.

Table B-1. Crude Oil System Pump Stations and Terminal

Milepost	Facility Name	Tier	Elevation	
			Suction	Discharge
457.54	Crane	II	2524	2524
416.64	Texon	II	2673	2673
373.60	Barnhart	II	2603	2603
344.28	Cartman	II	2446	2446
295.19	Kimble County	II	2221	2221
260.17	James River	I	1709	1709
227.94	Eckert	I	1726	1726
181.60	Cedar Valley	II	1035	1035
141.78	Bastrop	I	386	386
112.90	Warda	I	359	359
67.95	Buckhorn	I	171	171
34.09	Satsuma	III	129	129
2.36	East Houston	II	42	42

Tier Classifications and HCAs (Items 1 and 2)

Kiefner received a listing of tier classifications and HCAs for the Longhorn System. There were no changes from 2014 to 2015.

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.

Charpy V-Notch Impact Energy Data (Item 14)

Charpy V-Notch (CVN) impact tests are used to determine material toughness. 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 (TDW). 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	45,000 SMYS	13	26.0	62
13	156.59	45,000 SMYS	16	32.0	107.3
16	210.57	45,000 SMYS	18	26.9	103.7
18	227.20	45,000 SMYS	25.5	38.0	144
20	280.50	45,000 SMYS	24	48.0	94.6
23	316.57	45,000 SMYS	16.5	25.0	74
32	43.15	45,000 SMYS	16	32.0	109.4
33	134.66	45,000 SMYS	29	38.7	147
34	163.20	45,000 SMYS	21	31.3	140.3
35	341.65	45,000 SMYS	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

No Charpy V-Notch tests were conducted during 2015.

B.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, 2015 pressure and flow data have also been received for Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn Pump Stations. From September 1, 2015 to December 31, 2015 pressure and flow data have been received for Speed Junction Station. The data are collected in 1-minute intervals and sent on a monthly basis.

B.3. ILI Inspection and Anomaly Investigation Reports

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

Data were received from a total of 47 maintenance reports for evaluations completed in 2015. Table B-3a shows the breakdown of where the maintenance reports occurred (HCA, 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 2015

Line Segment	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Texon	18" Texon to Barnhart	18" Barnhart to Cartman	18" Cartman to Kimble County	18" Kimble County to James River	18" James River to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Bastrop	18" Bastrop to Warda	18" Warda to Buckhorn	18" Buckhorn to Satsuma	20" Satsuma to E. Houston	20" E. Houston to Speed Jct	8" El Paso to Chevron	12" El Paso to Kinder Morgan	8" Crane to Odessa
ILI Date			7/17/15	8/11/15	8/24/15	8/29/15	9/1/15	8/19/15	3/27/15	1/10/15	1/11/15	12/16/14	12/18/14					
Maintenance Report	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	No	Yes	No	No	No	Yes
Tier I	0	1	0	0	0	0	0	3	0	1	0	1	0	0	0	0	0	0
Tier II	0	0	1	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0
Tier III	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0
Total Digs	0	1	1	0	0	0	0	3	0	1	0	1	0	7	0	0	0	0
HCA	0	1	0	0	0	0	0	0	0	0	0	0	0	7	0	0	0	0
Non-HCA	0	0	1	0	0	0	0	3	0	1	0	1	0	0	0	0	0	0

Table B-3b. Reported Anomalies Excavated per the 2015 Maintenance Reports

ILI Anomaly Called	Number of Anomalies Addressed	18" El Paso to Cottonwood	18" Cottonwood to Crane	18" Crane to Texon	18" Texon to Barnhart	18" Barnhart to Cartman	18" Cartman to Kimble County	18" Kimble County to James River	18" James River to Eckert	18" Eckert to Cedar Valley	18" Cedar Valley to Bastrop	18" Bastrop to Warda	18" Warda to Buckhorn	18" Buckhorn to Satsuma	20" Satsuma to E. Houston	20" E. Houston to Speed Jct	8" El Paso to Chevron	12" El Paso to Kinder Morgan	8" Crane to Odessa
Ext Metal Loss	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Int Metal Loss	1	0	1	0	0	0	0	0	0	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	0	0	0	0	0	0
Lack of Fusion External	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Mid-wall	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
Lack of Fusion Internal	2	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0
Lamination Intermittent	0	0	0	0	0	0	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	0	0	0	0	0	0
Lamination Sloping	0	0	0	0	0	0	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	0	0	0	0	0	0
Lamination Bulging	0	0	0	0	0	0	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	0	0	0	0	0	0
Lamination	0	0	0	0	0	0	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	0	0	0	0	0	0
ID Reduction L<1.5D	0	0	0	0	0	0	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	0	0	0	0	0	0
ID Reduction on Weld	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0
ID Reduction w/associated metal loss	4	0	0	1	0	0	0	0	0	0	1	0	1	0	1	0	0	0	0
ID Reduction affecting pipe curvature at seam weld	4	0	0	0	0	0	0	0	2	0	0	0	0	0	2	0	0	0	0
Girth Weld Anomaly	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hard Spot Investigation	0	0	0	0	0	0	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	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	0	0	0	0	0	0
Area Of Bulge	0	0	0	0	0	0	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	0	0	0	0	0	0
Weld Irregularity	0	0	0	0	0	0	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	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	0	0	0	0	0	0
TOTAL	**14**	**0**	**1**	**1**	**0**	**0**	**0**	**0**	**3**	**0**	**1**	**0**	**1**	**0**	**7**	**0**	**0**	**0**	**0**

Results of ILI for TPD between 9th Street Junction and Crane (Item 77)

There was no sign of third-party damage identified by the ILI runs.

Results of Ultrasonic ILI for Laminations and Blisters between 9th Street Junction and Crane (Item 78)

Based on the 2015 excavation reports and comparison between the 2015 ILI assessments with 2010 UT assessments, no confirmed blisters have been found on the original Longhorn segments. No laminations were excavated in 2015.

B.4. Hydrostatic Testing Reports

Hydrostatic Leaks and Ruptures (Item 75)

No hydrostatic tests were performed on the Longhorn Pipeline System during 2015.

B.5. Corrosion Management Surveys and Reports

Corrosion Control Survey Data (Item 24)

Corrosion Control Survey data were 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 6.2.

External Corrosion Growth Rate Data (Item 36)

The 2006/2007 MFL data and 2015 MFL data were correlated to determine external corrosion growth rates for anomalies detected by each tool. The observed upper bound corrosion growth rate between Satsuma to Eckert ranged from 3.7 mpy to 6.0 mpy. These corrosion growth rates are consistent with the 5.0 mpy rate found in a previous external corrosion growth study. Additional details can be found in Section 6.2.

Internal Corrosion Coupon Results (Item 37)

Internal corrosion coupon reports were reviewed at 13 locations along the Longhorn system. 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 at 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)	Comments
Crude Line								
12	Crane	Centurion – Delivery to Crane	S9316	12/29/2014	5/4/2015	126	0.12	
12	Crane	Centurion – Delivery to Crane	U4380	5/4/2015	9/4/2015	123	0.00	
12	Crane	Centurion – Delivery to Crane	S9560	9/4/2015	12/29/2015	116	0.02	
16	Crane	Advantage – Delivery to Crane	S9315	12/29/2014	5/4/2015	126	0.09	
16	Crane	Advantage – Delivery to Crane	U4381	5/4/2015	9/4/2015	123	0.09	
16	Crane	Advantage – Delivery to Crane	S9562	9/4/2015	12/29/2015	116	0.03	
16	Crane	Plains WTI – Delivery to Crane	S9313	12/29/2014	5/4/2015	126	0.03	
16	Crane	Plains WTI – Delivery to Crane	U4383	5/4/2015	9/4/2015	123	0.00	
16	Crane	Plains WTI – Delivery to Crane	S9561	9/4/2015	12/29/2015	116	-6.36	Residual on coupon
16	Crane	Plains WTS – Delivery to Crane	S9312	12/29/2014	5/4/2015	126	0.03	
16	Crane	Plains WTS – Delivery to Crane	U4379	5/4/2015	9/4/2015	123	0.00	
16	Crane	Plains WTS – Delivery to Crane	S9564	9/4/2015	12/29/2015	116	0.03	
18	Cartman	Carman Station ML (6645)	E4970	12/29/2014	4/21/2015	123	0.00	
18	Cartman	Carman Station ML (6645)	g2824	4/21/2015	8/20/2015	121	0.00	
18	Cartman	Carman Station ML (6645)	G2806	8/20/2015	12/8/2015	110	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	E4964	1/2/2015	5/9/2015	127	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	g2825	5/9/2015	9/3/2015	117	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	G2807	9/3/2015	1/4/2016	123	0.03	
18	Satsuma	Satsuma Station ML (6645)	D4963	1/2/2015	4/9/2015	117	0.02	
18	Satsuma	Satsuma Station ML (6645)	g2826	4/29/2015	9/1/2015	125	0.00	
18	Satsuma	Satsuma Station ML (6645)	G2808	9/1/2015	12/31/2015	121	0.08	
20	East Houston	East Houston ML (6645)	S9501	12/31/2014	4/28/2015	118	0.01	
20	East Houston	East Houston ML (6645)	u4378	4/28/2015	8/31/2015	125	0.01	
20	East Houston	East Houston ML (6645)	S9563	8/31/2015	12/30/2015	121	0.04	
20	Speed Jct.	Speed Jct Manifold from E. Houston (6643)	E4971	12/30/2014	5/1/2015	122	0.01	
20	Speed Jct.	Speed Jct Manifold from E. Houston (6643)	g2823	5/1/2015	9/1/2015	123	0.00	
20	Speed Jct.	Speed Jct Manifold from E. Houston (6643)	G2725	9/1/2015	12/16/2015	106	0.00	
24	Crane	Tank Manifold to Crane	E4962	12/29/2014	5/4/2015	126	0.02	
24	Crane	Tank Manifold to Crane	g2822	5/4/2015	9/4/2015	123	0.00	
24	Crane	Tank Manifold to Crane	G2805	9/4/2015	12/29/2015	116	0.04	
Refined Line								
8	Crane	Odessa to Crane 8” (6648)	S9308	12/29/2014	5/4/2015	126	0.01	
8	Crane	Odessa to Crane 8” (6648)	u4382	5/4/2015	9/4/2015	123	0.04	
8	Crane	Odessa to Crane 8” (6648)	S9565	9/4/2015	12/29/2015	116	0.04	
8	El Paso	Plains 8” (6650) - Outbound	N0005	12/30/2014	5/1/2015	122	0.00	
8	El Paso	Plains 8” (6650) – Outbound	AX0102	5/1/2015	9/1/2015	123	0.00	
8	El Paso	Plains 8” (6650) – Outbound	AX0060	9/1/2015	12/31/2015	121	-0.80	Residual on coupon
18	El Paso	18” Mainline (6645)	N0001	12/30/2014	5/6/2015	127	0.00	
18	El Paso	18” Mainline (6645)	No162	5/6/2015	9/1/2015	118	0.00	
18	El Paso	18” Mainline (6645)	AX0062	9/1/2015	12/31/2015	121	0.00	

Line Pipe Anomalies/Repairs (Item 43)

A number of potential integrity threats were addressed in 2015. These included investigations (anomaly, POE, and 3rd party), new line crossings, ROW repair, valve replacement, road crossings, line removal, and addressing exposed pipe. Table B-5 lists the maintenance performed based on the 47 maintenance reports.

Table B-5. Maintenance Report Items

Maintenance Report Items	Number
A-sleeve cut out	0
AC mitigation	0
Anomaly Investigation	10
POE Investigation	0
3rd Party Investigation	0
Remove Re-circulation Valve & Replace Piping	0
Repair Washed Out Culvert	0
Shallow Pipe Repair at Road Crossing	8
New Road Crossing	1
4" Pipeline Removal	3
Corrosion cut out	0
Dent cut out	0
Address exposed pipe	4
New 12" Poly Line Crossing	2
New 16" Poly Line Crossing	2
New 10" Pipeline Crossing	1
New 16" Pipeline Crossing	2
New Water Line Crossing	1
New Power Line Crossing	5
New Fence Installation	1
Fence Repair	1
ROW Repair	2
Installed Metal Bands to Identify Composite Repair	1
Valve Stem Replacement	2
Positive Material Testing	9
Unauthorized Encroachment	1

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

See Section B.3 above.

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

See Section B.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 B.3 above.

B.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 2015.

Periodic Fault Benchmark Elevation Data (Item 31)

Semi-annual fault displacement monitoring was performed on June 15, 2015 and December 4, 2015 which covers semi-annual fault measurements at the seven fault monitoring sites from inception in mid-2004[8] through December 2015.

Pipeline Maintenance Reports for Stream Crossings

Scour reports were received for the two stream crossings, the Colorado River, its tributary Pin Oak Creek which were last monitored in December 2015. The reports for this year are missing distances for the stream crossing from the toe of the slopes from each side of the Colorado River. These data were missing for both rivers in 2014 but was measured at Pin Oak Creek in 2015.

Flood Monitoring

Flood monitoring spreadsheets were received for the Colorado River, Pin Oak Creek, and Pedernales River. There were two incidents in 2015 where the water surface was above the flood stage at both Colorado River and Pin Oak Creeks.

[8] The monitoring started in mid-2012 for three faults passed by the 2012 constructed pipeline connecting the existing Longhorn line to East Houston.

Waterway Inspection

The depth of cover above the pipes crossing the bottom of Pin Oak Creek and the bottom of Colorado River were inspected on July 6 and July 8 in 2015, respectively. No exposures of the pipeline at the two stream beds were found.

Other Earth Movement Monitoring

Every five years, an aerial survey of the pipeline is required to examine areas of concern (AOCs) which are high relief areas or where pipeline exposure was found. The latest aerial survey was completed on October 27 and 28 in 2015.

B.7. Maintenance and Inspection Reports

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

Three new exposures were identified in 2015 and subsequently additional cover was added. One site that has been actively managed under the Outside Forces Damage Prevention Program in accordance with the SIP was also repaired after additional erosion was found. Additionally, nine road crossings and three ditch water crossing areas were remediated along the line. There was no third-party damage found at any of the remediated locations.

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)

Kiefner received and reviewed Magellan's Mainline Valve Inspection Procedure (7.13-ADM-1035) which establishes the process for DOT mainline valve inspections in accordance with 49 CFR Part 195.420. We also received the bi-annual inspection reports for 2015.

Mechanical Integrity Evaluations (Item 47)

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.

Kiefner received the CMS Year End Task Report for 2015.

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 the following Facility Safety Reviews for 2015.

Table B-6. Facility Safety Reviews

Facility	Inspection Date
El Paso Terminal	2/18/15
El Paso Junction	2/20/15
Cottonwood	10/13/15
Crane	4/15/15
	7/08/15
	9/03/15
Texon	9/03/15
Barnhart	8/04/15
Cartman	9/14/15
Kimble	3/23/15
James River	3/23/15
Eckert	3/23/15
Cedar Valley	5/30/15
Bastrop	3/24/15
Warda	3/24/15
Buckhorn	3/25/15
Satsuma	3/31/15

The pump stations are remotely operated and controlled and generally are not manned. Technicians are onsite on a regular basis to perform routine maintenance and operation activities. Technicians are also on-call to respond to emergencies or other operational events at any time. Pump stations located in sensitive and hypersensitive areas are inspected every two and one-half days. Additionally, remote cameras are in place for monitoring purposes. Atmospheric Inspection surveys are conducted annually at pre-assigned above ground piping and facilities.

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.

B.8. Project Work Progress and Quality-Control Reports

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

Table B-7. Number and Status of Action Items per Month for 2015

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	71	25	27	34	37	30	29	37	32	33	41	35	431
Completed	71	25	27	30	37	30	29	37	32	32	39	34	423
Open at End of Month	0	0	0	4	4	4	4	4	4	5	7	8	8

B.9. Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-8. Service Interruptions per Month for 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total*
No./Month	2	1	0	3	2	2	1	0	0	0	0	0	11

* From the Daily Ops Report ending Dec 31, 2015.

B.10. Incorrect Operations and Near-Miss Reports

During 2015 there were 18 incidents within the Longhorn Pipeline System. Fourteen of the incidents involved human error, most of which were due to procedures not being followed or incorrect instruction and/or procedures. Three of these incidents involved incorrect valve lineups to station tanks leading to line overpressure and system shutdown. Six of the human error events involved contractors, four involved a third-party, and five involved Magellan employees. Corrective actions were identified and implemented.

There were nine near-miss events. A near-miss is 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. During 2015 there were four ROW near-misses and five hazard near-misses. Three of the ROW near-misses were one-call violations. The fourth involved a contractor installing a sewer line near the right-of-way. The incident was not a one-call violation or unauthorized encroachment; however, the work was close enough to the line to be deemed a hazard near-miss.

B.11. One-Call Violations and Third-Party Damage Prevention Data Right-of-Way Surveillance Data (Item 50)

The annual Third-Party Damage (TPD) Prevention Program Assessment contains Longhorn specific information. Data included in this assessment include the number of detected unauthorized right-of-way encroachments, changes in activity levels and one-call frequency, physical hits, near misses, depth of cover (DOC), and repairs that occurred along the pipeline. Potential TPD such as dents, scrapes, and gouges detected by in-line inspection tools and maintenance activities are also part of this assessment.

Kiefner received a complete log of aerial and ground surveillance data for 2015. 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.

Third Party Damage, Near-Misses (Item 51)

In 2015 there were four ROW near-misses, three of which were one-call violations. There was no third-party contact with the pipe.

Unauthorized ROW Encroachments (Item 52)

There were 44 ROW encroachments recorded in 2015, two 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 2015 TPD Annual Assessment. There were three one-call violations.

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

The 2015 TPD Annual Assessment shows a 39% increase in non-company activities level from unique aerial patrol observations. This is primarily due to an increase in housing developments.

Aerial patrol data indicated that agricultural activity was observed 17 times (3.6% of non-company observations) in 2015, seven times (2.1% of non-company observations) in 2014, and 2 times (0.4% of non-company observations) in 2013. These data correlate with the fact that only a small percentage of the Longhorn Pipeline system traverses agricultural areas.

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 mile 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-9. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Aerial Patrol													
301: MP528 to E. Houston	9,375	10,250	11,606	14,113	11,598	13,620	16,558	15,930	15,515	15,027	12,171	12,999	158,762
303: MP528 to MP694	1,320	1,056	1,320	792	1,320	1,056	1,320	1,320	1,056	792	1,056	1,320	13,728
Ground Patrol													
Edwards Aquifer	39.2	30.8	33.6	19.6	25.2	16.8	11.2	16.8	16.8	19.6	25.2	28	282.8

Magellan was able to meet the Longhorn commitment to inspect Tier II and III areas (Segment 301) from the East Houston Terminal to the Pecos River at least every 72 hours with one exception during late May (5/22 – 5/25) from MP456 to MP528 due to bad weather.

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from Crane (MP457) to the El Paso Terminal (MP694).

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

Table B-10. Markers Repaired or Replaced

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
No. Repaired or Replaced	15	10	2	3	1	13	57	24	1	3	1	0	130

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-11 shows the number of educational and outreach meetings held in 2015.

Table B-11. Educational and Outreach Meetings

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25	30
School Program:											
School Program - Houston	2	2	3	4		6	5	6	1	3	4
School Program - Austin	3	2	7	3	4	3	4	5	5	2	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	36

NOTE: Public meetings were tallied for the years 2005-2015 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 and by tier for 2015 is listed in Table B-12 below.

Table B-12. Number of One-Calls by Tier

Tier	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
I	382	326	375	387	294	375	396	382	392	378	338	277	4,302
II	791	704	757	848	704	903	906	680	718	755	738	679	9,183
III	261	230	262	314	253	300	323	228	247	262	251	236	3,167
Total	1,434	1,260	1,394	1,549	1,251	1,578	1,625	1,290	1,357	1,395	1,327	1,192	16,652

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 during 2015 is shown in the following table.

Table B-13. Number of Website Visits

Page Name	Jan	Feb	Mar	Apr	May	Jun	July	Aug	Sept	Oct	Nov	Dec	Total
Safety/Environment	218	199	216	233	190	209	201	188	184	210	198	159	2405
Pipeline Safety	117	126	131	138	113	108	119	105	82	83	81	84	1286
Call Before You Dig	50	47	63	89	52	49	77	51	48	31	37	43	637
Call Before You Dig Video	0	0	0	6	2	0	3	0	0	1	2	0	14
System Integrity Plan	113	100	112	95	91	102	79	75	92	67	73	80	1079
Longhorn Info.	415	467	453	411	277	270	260	243	237	237	178	178	2626
Pipeline Emergencies	26	20	36	37	29	22	55	20	27	26	33	32	372
Home Page – 811	0	0	1	0	0	0	0	1	0	1	0	0	3

Number of ROW Encroachments by Month (Item 67)

The number of ROW encroachments during 2015 is shown in the following table. The Annual TPD Report identified 44 encroachments, two of which were unauthorized.

Table B-14. Table of ROW Encroachment by Month

Encroachments	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Authorized	1	3	3	4	1	1	9	4	5	3	5	3	42
Unauthorized	2	0	0	0	0	0	0	0	0	0	0	0	2
Total	3	3	3	4	1	1	9	4	5	3	5	3	44

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

No physical hits were reported from 2012 through 2015. 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 Longhorn System 2015 Annual Third-Party Damage Prevention Program Assessment (TPD Annual Assessment) was received in July 2016. Much of the data received in this report are used to summarize other parts of Sections 3.5 and 6.6 on third-party damage prevention.

One-Call Activity Reports (Item 72)

A summary of one-call activity by month is supplied in Table B-15 below as extracted from the TPD Annual Assessment. Results show that 16,652 one-call notifications were made.

Table B-15. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	618	332	1,434
Feb	624	215	1,260
Mar	690	216	1,394
Apr	783	211	1,549
May	732	162	1,251
Jun	830	210	1,578
Jul	874	202	1,625
Aug	592	153	1,290
Sep	624	204	1,357
Oct	685	195	1,395
Nov	726	218	1,327
Dec	624	183	1,192
Totals	8,402	2,501	16,652

B.12. Incident, Root Cause, and Metallurgical Failure Analysis Reports

During 2015 there were 18 incidents within the Longhorn Pipeline System. Two of the incidents involved releases, but were not DOT-reportable. The first occurred at Crane Station where a vacuum truck was used to drain-up a manifold supplying tank to install two new valves. The driver (contractor) dropped the end of the hose into the manifold pit – and the hose valve leaked 40 gallons of crude oil into the concrete pit. Causes for this incident were failure to follow procedures, lack of training, and equipment (valve) failure. The second incident occurred at El Paso, which involved installing a blind flange on Tank 10. The bolts of the blind flange were not properly tightened resulting in a release of 84 gallons of refined product.

Four of the incidents occurred along the pipeline, 14 occurred at facilities. Of the four pipeline incidents, three were one-call violations, with no contact or damage to the pipeline.

Eight incidents were classified as minor, one significant, and nine were near-misses. The significant incident occurred at Crane Station during excavation for new cable tray supports. During the excavation the driller hit an unmarked live electrical conduit. Fortunately the driver was not injured. The incident investigation identified the cause was a failure to follow procedures, including: *Pipeline Locating Procedure, Review of Facility Drawings and Alignment Sheets, Excavation Safety Procedure,* and *Requiring a Company Representative with Knowledge of the Facility to be Present Prior to and During Excavation*.

Fourteen of the incidents involved human errors, mostly due to procedures not being followed or incorrect instruction and/or procedures. Three of these incidents involved incorrect valve lineups to station tanks leading to line overpressure and system shutdown. Five involved contractors, four involved a third-party, and five involved Magellan employees. Corrective actions were identified and implemented.

There were no metallurgical failure analyses conducted during 2015.

B.13. Other LPSIP/Risk Analyses, Evaluations, and Program Data

The objective of Magellan's Scenario-Based Risk Mitigation Analysis (SBRMA) program is to identify preventive measures and/or modifications that can be recommended that would reduce the risks to the environment and the population in the event of a product release.

Magellan's probabilistic risk model utilizes integrated data and incorporates a dynamic segmentation process to maintain adequate resolution and avoid mischaracterization or loss of detail. The risk measurement methodology includes Point of Failure (PoF) threshold management to manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The PoF measurement integrates all available information about the integrity of the pipeline. This integration aids in identification of preventive and mitigative measures to protect areas along the pipeline. Magellan is committed to maintain at or below 1×10^{-4} (0.0001) failures (PHMSA reportable incidents) per mile-year at all locations along the non-facilities portions of the pipeline.

The pipeline risk model was updated with information from operations in 2015 and executed. Results show no areas along the pipeline with PoF greater than 1×10^{-4} failures and as such supports the effectiveness of Magellan's existing Integrity Management Program. No additional mitigative measures are required or recommended at this time.

Magellan's risk model is updated periodically as new information becomes available.

The Longhorn Mitigation Plan (LMP) requires that all changes on the Longhorn system "be evaluated using an appropriate hazard analysis (HAZOP, What-if, LOPA etc.)." The Magellan Management of Change Recommendation (MOCR) form includes a yes / no checkbox to indicate whether a Process Hazard Analysis (PHA) is required, and Magellan's procedures provide that the asset integrity engineer should determine the appropriate PHA methodology for change requests.

One Process Hazard Analysis (PHA) was conducted in 2015 for a pending project that will provide additional product in to East Houston with the potential to pump to Speed Junction; however, it is currently not expected to impact LMP physical assets.

B.14. Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity

PHMSA Advisories

DEPARTMENT OF TRANSPORTATION ADB-2015-02 June 23, 2015
Pipeline and Hazardous Materials Safety Administration
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2015-0140
Summary: PHMSA-2015-0140
Advisory: All owners and operators of gas and hazardous liquid pipelines are reminded that pipeline safety problems can occur from the passage of hurricanes. Pipeline operators are urged to take the following actions to ensure pipeline safety:

1. Identify persons who normally engage in shallow-water commercial fishing, shrimping, and other marine vessel operations and caution them that underwater offshore pipelines may be exposed or constitute a hazard to navigation. Marine vessels operating in water depths comparable to a vessel's draft or when operating bottom dragging equipment can be damaged and their crews endangered by an encounter with an underwater pipeline.
2. Identify and caution marine vessel operators in offshore shipping lanes and other offshore areas that deploying fishing nets or anchors and conducting dredging operations may damage underwater pipelines, their vessels, and endanger their crews.
3. After a disruption, operators need to bring offshore and inland transmission facilities back online, check for structural damage to piping, valves, emergency shutdown systems, risers and supporting systems. Aerial inspections of pipeline routes should be conducted to check for leaks in the transmission systems. In areas where floating and jack-up rigs have moved and their path could have been over the pipelines, review possible routes and check for sub-sea pipeline damage where required.
4. Operators should take action to minimize and mitigate damages caused by flooding to gas distribution systems, including the prevention of overpressure of low pressure and high pressure distribution systems.

DEPARTMENT OF TRANSPORTATION ADB-2015-01 April 9, 2015
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
80 FR 68 - 19114
Docket Number: PHMSA-2015-0105
Notice: Issuance of Advisory Bulletin
Summary: PHMSA is issuing this updated advisory bulletin to all owners and operators of gas and hazardous liquid pipelines to communicate the potential for damage to pipeline facilities caused by severe flooding. This advisory includes actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, and river channel migration.
Link:
http://phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Advisory%20Notices/ADB_2015_01.pdf

B.15. DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2015.

B.16. Literature Reviewed

See references.