Magellan Pipeline Company

Final Report No. 18-048

2016 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Adam Steiner, PE, Benjamin Wright,
Fan Zhang, PhD, Mark Ryan, Dennis Johnston, and Dyke Hicks

March 29, 2018

0010-1709

Intentionally blank

Final Report No. 18-048

Final Report

on

2016 OPERATIONAL RELIABILITY ASSESSMENT OF THE LONGHORN PIPELINE SYSTEM

to

MAGELLAN PIPELINE COMPANY

March 29, 2018

Prepared by

Susan Rose
Principal Engineer

Approved by

Carolyn E. Kolovich
Vice President, Pipeline

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

0010-1709

DISCLAIMER

This document presents findings and/or recommendations based on engineering services performed by employees of Kiefner and Associates, Inc. The work addressed herein has been performed according to the authors' knowledge, information, and belief in accordance with commonly accepted procedures consistent with applicable standards of practice, and is not a guaranty or warranty, either expressed or implied.

The analysis and conclusions provided in this report are for the sole use and benefit of the Client. No information or representations contained herein are for the use or benefit of any party other than the party contracting with Kiefner. The scope of use of the information presented herein is limited to the facts as presented and examined, as outlined within the body of this document. No additional representations are made as to matters not specifically addressed within this report. Any additional facts or circumstances in existence but not described or considered within this report may change the analysis, outcomes and representations made in this report.

EXECUTIVE SUMMARY

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2016 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which provides 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 and mitigate areas of potential concern.

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 2021 for the Barnhart to Texon segment. Transverse field inspection (TFI) tool runs, completed in 2014 and 2015 were used to define a flaw size that determined the reassessment interval. Twenty-nine seam weld features were identified during the 2015 TFI and were remediated during 2016. The reassessment interval used the seam weld feature detection threshold value from the TFI tool vendor.

The 2016 maintenance reports were reviewed and correlated to the 2015 and 2016 in-line inspection (ILI) assessments to validate the ILI specified tool performance using the supplied background information and the API 1163 ILI validation methodology. The ILI anomaly investigations found correlating features on 152 out of the 154 digs; the remaining two digs did not report any features within the exposed location. ILI reported metal loss anomalies were found as metal loss in-ditch two thirds of the time. Internal corrosion coupons continue to show very low (<0.07 mpy) corrosion rates. Magellan should continue to conduct field investigations to remediate and validate metal loss reported on future ILI assessments, as necessary.

- Advanced NDE methodologies, such as Automated UT (AUT), that have a high resolution are recommended for in-ditch evaluations to help characterize and size complex anomalies that are within the pipe body.
- Kiefner recommends that Magellan consider pipeline cutouts to allow for metallurgical investigation if an in-ditch anomaly is difficult to characterize through non-destructive testing.

- Kiefner recommends that Magellan continue to look into advanced technology that will help assess interacting threats such as: dents with metal loss, dents with mechanical damage or gouges, and laminations with metal loss or denting. It is recommended that the advanced technology be incorporated into the regular assessment intervals.

A Close Interval Survey (CIS) was performed by a third party in July and August of 2016 on Longhorn Tier III (environmentally sensitive) sections. Magellan identified and corrected misalignments found in the CIS report around MP 34. A realignment and interference test verified that there were no areas of deficiency at the MP 34 location identified in the CIS report. A follow-up survey will be completed in 2017.

Laminations were reviewed concurrently with reported inside diameter (ID) reductions to determine if there were any potential hydrogen blisters on the line segments inspected in 2016. The ID reductions identified from the 2016 ILI assessments were compared to the existing laminations found from the 2010 UT assessments and no features correlated. Based on the 2016 maintenance reports and ILI assessments, there are currently no areas that have indications or field findings of hydrogen blisters associated with these line segments. Magellan should continue to monitor lamination anomalies with ILI tools for the possibility of blister formation and growth.

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 analyses 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 ORA. 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 Sections 3.4 and 8 of this ORA.

Waterway inspections of the Colorado River Crossing and its tributary Pin Oak Creek were conducted in 2016. No exposures of the pipeline at the waterways were found; however, an approximate 7-inch reduction of the minimum cover depth at the Pin Oak Creek was found over a one and a half year period between the latest inspection in December 2016 and the prior one in June 2015.

Magellan should continue to perform waterway inspections at the current frequency to monitor the conditions and perform further remediation at the Pin Oak Creek if necessary. Examples of further remediation include installing the pipeline deeper through horizontal directional drilling (HDD) or placing a concrete mat at the river bottom to prevent scouring.

In November 2016 there was a blasting operation conducted by a third party near the Longhorn Pipeline in Johnson City, Texas. Based on our review of Magellan's stress analysis, recorded ground vibration level at the pipeline location and the ILI indication of anomalies in the pipeline segment near the blasting sites, there was no damage to the pipeline as a result of the blasting operation.

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 no right-of-way (ROW) near-misses and no known cases of third-party contact with the pipeline during 2016. The absence of reportable incidents involving mainline pipe suggests the Longhorn proactive damage prevention and maintenance plans (including the aerial and ground surveillance frequency) have been effective and are functioning as intended.

No occurrence of stress-corrosion cracking (SCC) has ever been recorded on the pipeline, including the 449 miles of the Existing Pipeline. Magellan continues to carry out inspections as part of the normal dig program by conducting 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 2016, one can conclude that pump stations and terminal facilities have been properly maintained and operated and have had no adverse impact on public safety.

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 of patrol. 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 2016, there were eight non-DOT reportable incidents along the Longhorn Pipeline System. Four were minor incidents and four were hazard near-misses. Human error was the primary cause for six of the eight incidents, which generally involved a failure to follow procedures and/or ensuring that drawings are maintained current and accurate. Three of the human error events involved contractors. Magellan should continue to ensure all relevant data are recorded on the incident data reports, including a detailed description of the incident, root cause, as well as contributing factors to help improve the overall effectiveness of the incident investigation program.

TERMS, DEFINITIONS AND ACRONYMS

Many of the terms and definitions are taken directly from Section 2.0 of the ORA Process Manual (ORAPM) titled Terms, Definitions, and Acronyms. Definitions that are lifted directly from the ORAPM or Longhorn Mitigation Plan (LMP) are 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.
AC	Alternating Current
AOC	Area of concern
AOEC	Area of elevated concern
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AUT	Automated Ultrasonic Testing
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.
CPM	Computational Pipeline Monitoring
d	Defect depth
D	Pipe diameter, usually the outside diameter of the pipeline (also see, OD).

Excavation damage	Any excavation activity that results in the need to repair or replace a pipeline due to a weakening, or the partial or complete destruction, of the pipeline, including, but not limited to, the pipe, appurtenances to the pipe, protective coatings, support, cathodic protection or the housing for the line device or facility.
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 – The National Environmental Policy Act (NEPA) process begins when a federal agency develops a proposal to take a major federal action. These actions are defined in 40 CFR 1508.18. The environmental review under NEPA can involve three different levels of analysis: • Categorical Exclusion determination (CATEX) • Environmental Assessment/Finding of No Significant Impact (EA/FONSI) • Environmental Impact Statement (EIS)
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.

External Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe
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
HNM	hazard near-miss
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.
IMP	Integrity Management Program
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.
Internal Corrosion	Deterioration of the pipe due to an electrochemical reaction between the pipe material and the environment outside the pipe
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
Leak Detection System	Two technology-based leak detection systems are used for the Longhorn system: (1) A system-wide computer-based monitoring and alarm network using real-time flow information from various locations along the pipeline, and (2) a buried sensing cable installed over the Edwards Aquifer recharge zone and the Slaughter Creek watershed in the Edwards Aquifer contributing zone.
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.
LOPA	Layer of Protection Analysis
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	Per the Longhorn Mitigation Plan – 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	Per the Longhorn Mitigation Plan - 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.
NDE	Nondestructive Testing
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.
Normal Distribution	A probability distribution that is commonly referred to as the bell curve that is symmetrical around the mean value.

OD	Outside nominal diameter of line pipe.
One-Call	A notification system through which a person can notify pipeline operators of planned excavation to facilitate the locating and marking of any pipelines in the excavation area. 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
PMI	Positive Material Identification
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 (POED) is the probability that an anomaly is deeper than 80% of wall thickness. The

	POE for pressure (POEP) 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).

SBRMA	Scenario-Based Risk Mitigation Analysis
Significant Incident	Per the Longhorn Mitigation Plan - 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[1])
SIP	System Integrity Plan
SMFL	Spiral magnetic flux leakage – an MFL inspection tool
SMYS	Specified Minimum Yield Strength – A common measure of the minimum acceptable strength of pipe purchased from a manufacturer. A measurable metallurgical strength parameter often used to calculate acceptable pipe operating and hydrostatic test pressures.
Standard Deviation	A measure used to quantify the amount of variation or dispersion within a set of data.
Surge Pressure	Short-term pipeline pressure increase due to equipment operation changes such as valve closure or pump start-up. Surge pressures must be limited to no more than MOP in Tier II and Tier III areas, and no more than 110% of MOP elsewhere.
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 – Accidental or intentional damage by a third party (that is, not the pipeline operator or contractor) that causes an immediate failure or introduces a weakness (such as a dent or gouge) into the pipe.
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.

[1] ASME 31.8S (2016), Managing System Integrity of Gas Pipelines, ASME Code for Pressure Piping, B31

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
WTI	West Texas Intermediate (crude oil grade)
WTS	West Texas Sour (crude oil grade)

Intentionally blank

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

2016 Operational Reliability Assessment of the Longhorn Pipeline System

Susan Rose, Adam Steiner, Benjamin Wright, Fan Zhang, Mark Ryan, 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 2016 operating year. Kiefner and Associates, Inc. (Kiefner) conducted the ORA which provides 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 and mitigate areas of potential concern.

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” (FONSI) 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 retaining 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 the 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 12 elements of the LPSIP are:

1. Corrosion Management Plan

2. In-Line Inspection and Rehabilitation Program

3. Key Risk Area 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.

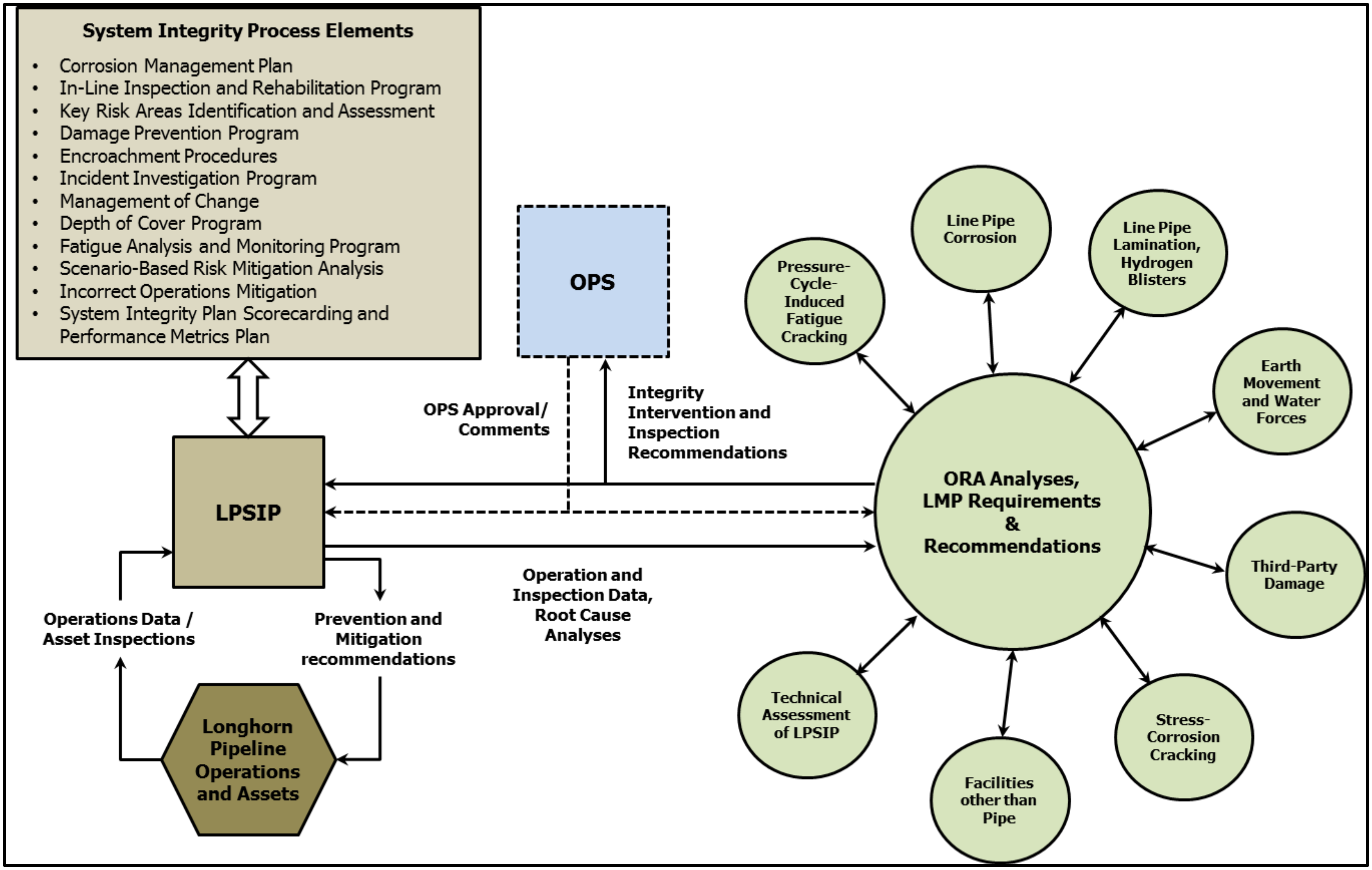


Figure 1. ORA Functions and Interaction with the LPSIP

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	Milepost
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	Milepost
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 2016.

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.

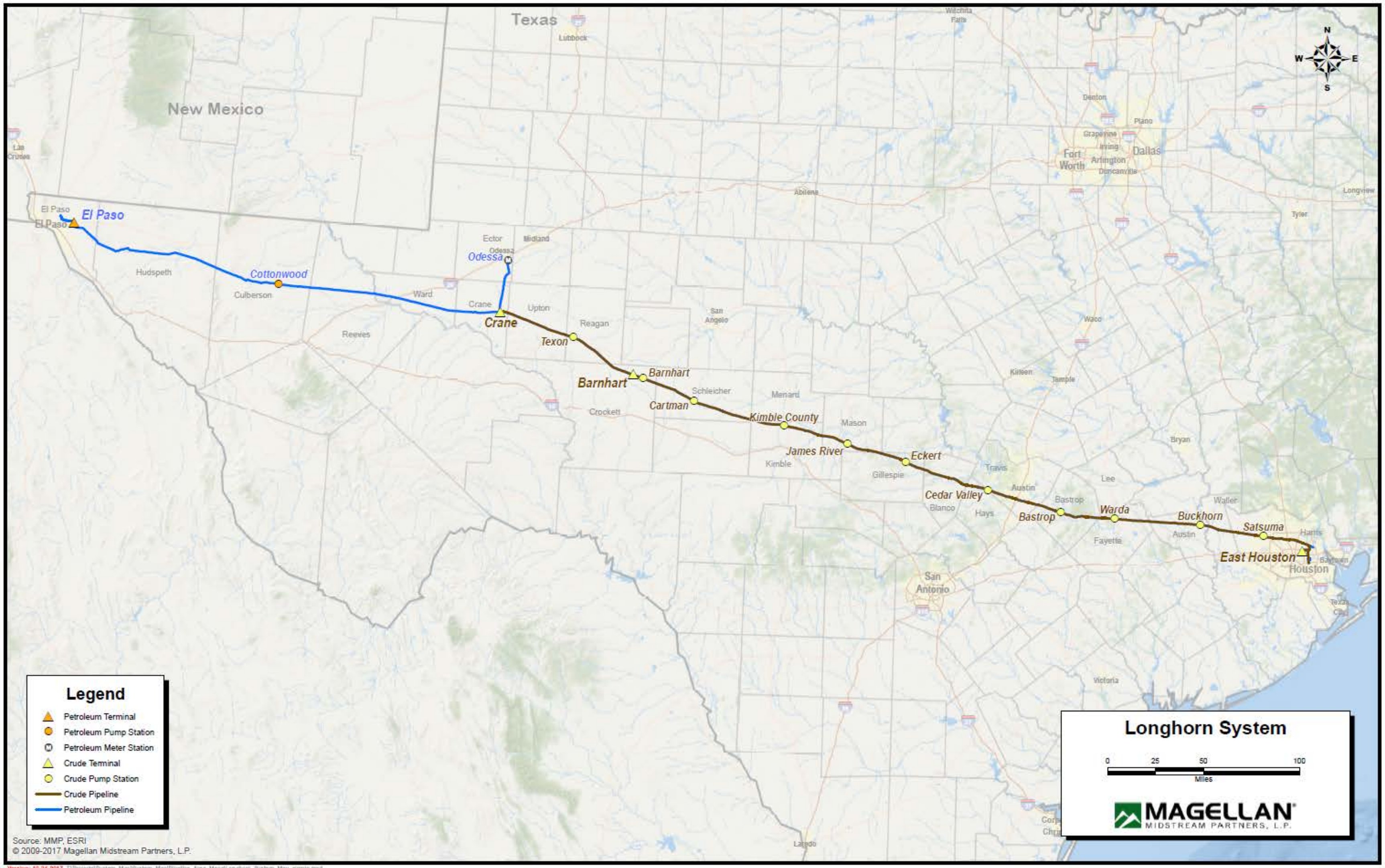


Figure 2. Longhorn System Map (2016)

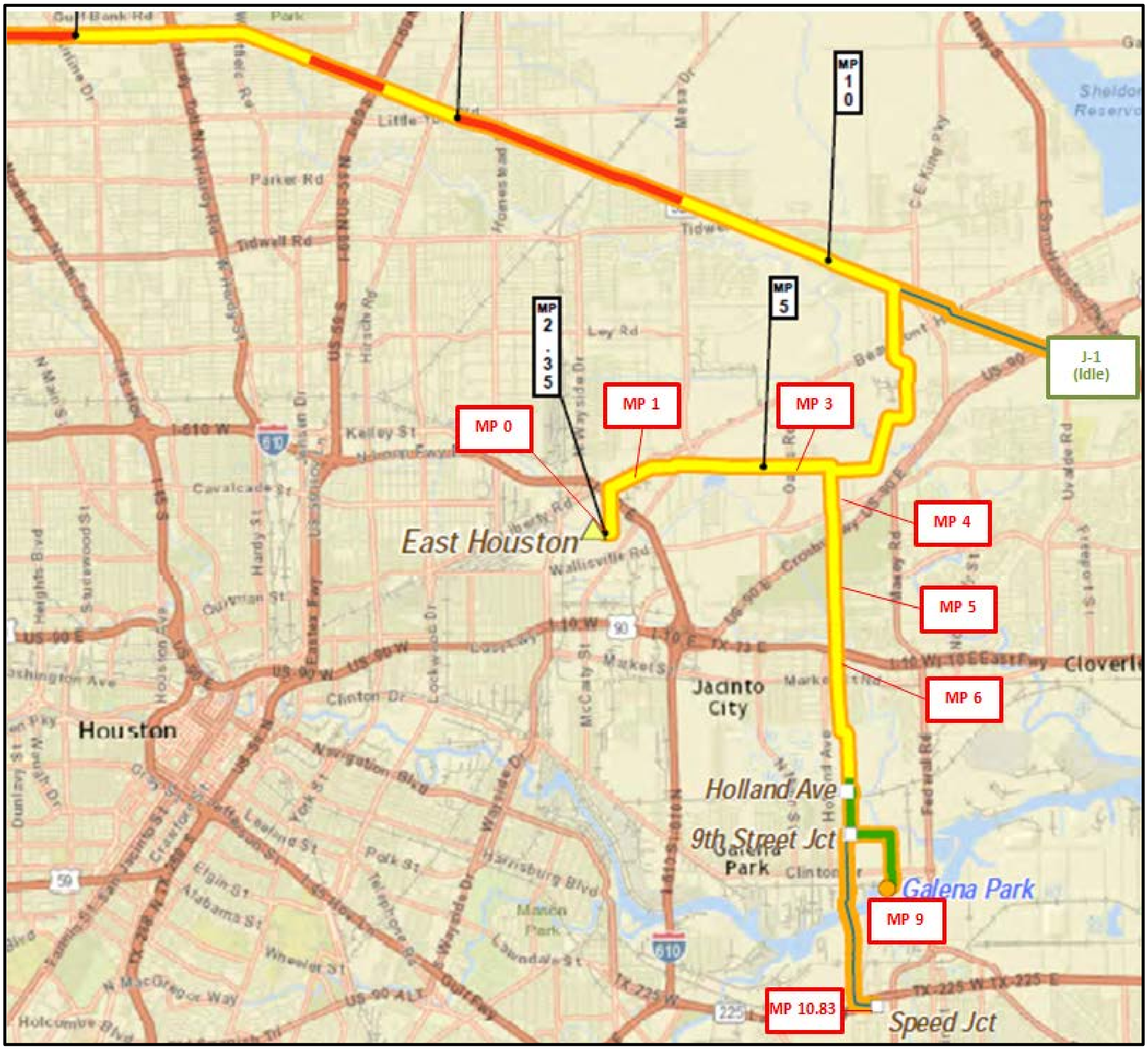


Figure 3. Map of Longhorn System within Houston Area (2016)

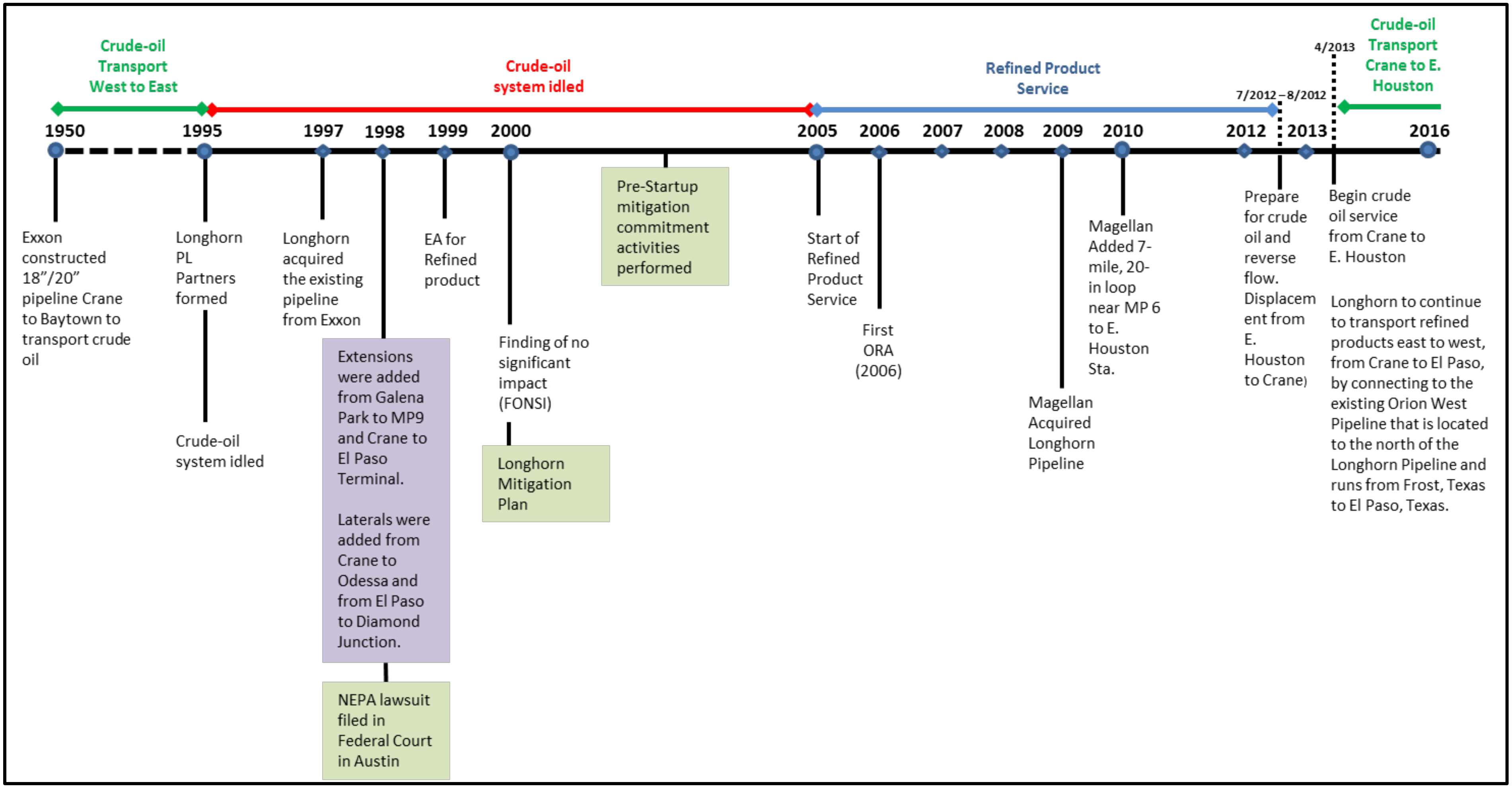


Figure 4. Timeline of the Longhorn Pipeline System

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 2016 CMP considers the following items: review of internal corrosion coupons, probability of exceedance (POE) analysis for the Crane to Odessa assessment, review of field dig reports (covered under Section 2.2, In-Line Inspection and Rehabilitation Program), and review of the cathodic protection system.

Internal corrosion is monitored using internal corrosion coupons. The coupon results have shown little change (<0.07 mpy) but monitoring should continue to identify future potential changes in the pipeline. Results from the internal corrosion coupons can be found in Appendix B, Table B-4.

POE calculations were performed on the magnetic flux leakage (MFL) assessment performed October 5, 2016 from Crane to Odessa. No metal loss features were found to meet POE dig requirements of 1 x 10^{-5}. Therefore, reliability-based design analysis (RBDA) calculations were not performed in 2016.

A close interval survey (CIS) was performed by Energy Maintenance Services (EMS) from July 19 through August 8, 2016, on Longhorn Tier III sections (sensitive areas due to population or environmental factors). The CIS reported potential values near MP 34 to be below the -850mV criterion set by NACE SPO 169 2007 and gave a recommendation of performing alternating current (AC) and direct current (DC) interference tests around MP 34.

While performing the recommended interference testing, Magellan identified and corrected misalignments in the CIS report. The realignment and interference testing results verified that there were no areas of deficiency at the MP 34 location called in the CIS report. A follow-up survey will be completed in 2017.

2.2. In-Line Inspection and Rehabilitation Program

One in-line inspection (ILI) assessment was performed from the Crane pump station to the Odessa meter station. The assessment was performed using T.D. Williamson's (TDW) SpirALL Magnetic Flux Leakage (SMFL) technology. Five transverse field inspection (TFI) assessments were run in December 2015, with results reported in 2016, between the Satsuma (MP 34.1) and Eckert (MP 227.9) pump stations. The TFI assessments were performed using General Electric (GE) TranScan technology. Inspection dates for each segment can be found in Table 3.

The 2016 ILI assessments and maintenance reports were reviewed to validate the ILI specified tool performance. The ILI assessments were reviewed using the supplied background information and the API 1163[3] ILI validation methodology. Magellan provided 154 maintenance reports related to 2015 and 2016 ILI investigations. The ILI investigation digs correlated to 501 ILI features (inside diameter (ID) reductions, ID reductions with metal loss, metal loss, and seam weld A and B features) that were evaluated in 2016 from the most recent ILI assessments. An overview of the dig results can be found in Table 10 for metal loss features, Table 11 for seam weld features, and Table 12 for deformation features. A Level 2 validation was performed and a statistical analysis on metal loss features from Crane to Satsuma was evaluated. Using an API 1163 Level 2 validation, the TFI tool performed no worse than its depth sizing specification. Magellan requires nondestructive testing of the pipe segment to determine pipe properties in at least 50% of the excavations or remediation required by ILI results if a segment of pipe does not have material documentation available. In 2016, excavations were completed on 141 segments that did not have material documentation available. Magellan met the requirement by performing material testing on 75 of the 141 segments.

2.3. Identification and Assessment of Key Risk Areas

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 risks.

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

[3] API Standard 1163, In-line Inspection Systems Qualification, Second Edition, April 2013

- Tier II – sensitive areas
- 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 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 2016. The results show that none of the pipeline segments exceeded the risk threshold; therefore no additional mitigative measures were required or recommended.

2.4. Damage Prevention Program

Third-party damage (TPD) refers to the accidental or intentional damage by a third party – that is, not the pipeline operator or contractor – that causes an immediate failure or introduces a weakness (such as a dent or gouge) in the pipe.

The Longhorn 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 2016.

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 ROW 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 ROW encroachments.

There were 57 encroachments recorded in 2016, two of which were unauthorized. Both were followed up with corrective actions to help prevent a recurrence. There was no damage to the pipeline. 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 Department of Transportation (DOT)-reportable incidents as well as smaller non-reportable incidents and near-miss events.

During 2016, there were eight incidents along the Longhorn Pipeline System. Three of these involved releases, but were not DOT-reportable. Incident investigations were performed on all eight incidents, including the near-miss events to determine the causes and corrective actions. Five of the incidents involved human error and three were due to equipment failures. Four incidents were minor and four were hazard near-misses. A hazard near-miss is defined as an undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property.

Three of the human error events involved contractors. Magellan should continue to ensure all relevant data are recorded on the incident data reports, including a detailed description of the incident, root cause, as well as contributing factors to help improve the overall effectiveness of the incident investigation program.

2.7. Depth-of-Cover Program

No new exposures were identified in 2016. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the LPSIP were repaired after additional erosion was found. 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 (DOC) above two segments is less than one or two feet (at the Colorado River and Pin Oak Creek Crossings) and will continue to be monitored.

As part of the 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 2016 fatigue analysis incorporated results from the 2014 Spiral MFL and 2015 TFI tool runs and was effective at monitoring the potential of fatigue cracking failures from pressure-cycle-induced growth. From the data obtained during the 2014 Spiral MFL and 2015 TFI tool runs, the shortest time to reassessment is calculated to be 2021. 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 when changes occur in existing facilities. Two PHAs were conducted during 2016: one for the El Paso Terminal Holly Receipt and Storage Project and the second was for the Crane Terminal Expansion.

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. The analyses conducted during 2016 did not result in any scenarios above this threshold.

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. "Incorrect Operations" is described as incorrect operation or maintenance procedures, or a failure of pipeline operator personnel to correctly follow procedures.

As discussed in Section 2.6, five of the incidents in 2016 involved human error/incorrect operations. 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 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. PHAs were conducted for the El Paso Terminal Holly Receipt and Storage Project and the Crane Terminal Expansion.

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 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. In addition, public-awareness meetings were held, and ROW markers and signs were repaired or replaced where necessary. From the standpoint of metal loss deterioration measures, there were no metal loss features that met POE dig requirements from the 2016 ILI runs. In terms of failure measures, there were no DOT-reportable incidents or third-party contact with the pipeline or facilities. However, there were four hazard near-miss events due to human error.

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 2021 was calculated as the segment with the shortest time to failure 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): 23-Aug-2202
- East Houston to Satsuma (MP 2.35 to MP 34.1):14-Nov-2032

- Satsuma to Buckhorn (MP 34.1 to MP 68.0): 31-Jan-2039
- Buckhorn to Warda (MP 68.0 to MP 112.9): 23-Oct-2027
- Warda to Bastrop (MP 112.9 to MP 181.6): 07-Apr-2025
- Bastrop to Cedar Valley (MP 141.8 to MP 181.6): 13-Aug-2046
- Cedar Valley to Eckert (MP 181.6 to MP 227.9): 30-Sep-2033
- Eckert to James River (MP 227.9 to MP 260.2): 05-Nov-2023
- James River to Kimble County (MP 260.2 to MP 295.2): 11-Sep-2027
- Kimble County to Cartman (MP 295.2 to MP 344.3): 29-Mar-2022
- Cartman to Barnhart (MP 344.3 to MP 373.4): 17-Jan-2040
- Barnhart to Texon (MP 373.4 to MP 416.6): 23-Jul-2021
- Texon to Crane (MP 416.6 to MP 457.5): 13-Apr-2022
- Crane to El Paso (MP 457.5 to MP 694.4): 29-Nov-2238

3.2. Corrosion

A reassessment schedule for monitoring corrosion can be found in Section 7, Table 21 for the Longhorn Crude system and in Table 22 for the Longhorn refined system. The next crude system assessment for corrosion is in 2019 from Warda through Speed Junction. The next refined system assessment for corrosion is 2017 for the following segments: 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, 12-inch El Paso to Kinder Morgan, and 18-inch Cottonwood to El Paso.

3.3. Laminations and Hydrogen Blisters

Laminations can occur as a result of oxides or other impurities trapped in the material. As the material cools in the manufacturing process, a small pocket may form internal to the steel plate or billet. A lamination can eventually lead to failure when it is oriented such that it eventually grows to the inner or outer wall of the pipe or pipeline component through pressure cycles. Laminations that are parallel to the surface of the pipe wall generally do not pose an integrity concern unless the formation of a blister occurs. Crude oil may 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 these threats.

Inside diameter reductions identified from the 2016 assessments were correlated with the reported laminations from the 2010 UT assessments. No reported ID reductions from the 2016 assessments were found to correlate with laminations. Per the Longhorn EA Section 9.3.2.3, the monitoring frequency recommended should coincide with the electronic geometry pig (EGP) tool assessment schedule. Section 9.3.2.3 requires an EGP assessment every three years in accordance with the LMP. A reassessment schedule for EGP assessments can be found in Section 7, Table 21 for the Longhorn Crude System and Table 22 for the Longhorn

Refined System. The next crude system EGP assessment is in 2017 for Warda through E. Houston. The next refined system EGP assessment is in 2017 for the following segments: 8-inch El Paso to Chevron, 8-inch Kinder Morgan Flush Line, 12-inch El Paso to Kinder Morgan, and 18-inch Cottonwood to El Paso.

3.4. Earth Movement, Water Forces, and Blasting

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. 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

Magellan replaced the indirect scour inspections at the river banks with waterway inspections to directly measure the remaining cover depth at the river bottom for both the Colorado River and Pin Oak Creek Crossings. Similar waterway inspections were completed for both Crossings in 2015 as well. The comparison of the waterway inspection results between 2015 and 2016 indicated no changes at the Colorado River Crossing and about a 7-inch reduction of minimum cover depth at the Pin Oak Creek Crossing.

Magellan should continue to perform waterway inspections at the current frequency to monitor the conditions and perform further remediation at the Pin Oak Creek if necessary. Examples of further remediation include installing the pipeline deeper through horizontal directional drilling (HDD) or placing a concrete mat at the river bottom to prevent scouring.

Blasting

In November 2016 there was a blasting operation conducted by a third party near the Longhorn Pipeline in Johnson City, Texas. Magellan conducted stress analyses and seismic monitoring of the ground vibration in this area. At approximately 650 feet from the pipeline the ground vibration generated a peak particle velocity (PPV) of 0.11 inch per second (ips). Based on a review of Magellan's blasting analysis, ground vibration monitoring records and ILI results for the pipeline segment near the blasting site, no damage to the pipeline should be expected as a result of the blasting. See Section 5.4 for further detail.

3.5. Third-Party Damage

For the threat of TPD, Magellan should continue with the current prevention and inspection activities. Prevention activities include ROW surveillance, One-Call System, and public-awareness activities that continued to be successful in 2016. 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). One ILI assessment was conducted in 2016 from Crane to Odessa using an SMFL inspection tool accompanied with an EGP inspection tool. For specific inspection dates to fulfill the requirement for each of the six intervals spanning the Existing Pipeline from East Houston to Crane see Section 7, Table 21 on Integration of Intervention Requirements.

3.6. Stress-Corrosion Cracking

SCC is a form of environmental attack of the pipe steel involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks. 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 PHA methodology (Hazard and Operability (HAZOP), Layer of Protection Analysis (LOPA), What-if Analysis)." Two PHAs were conducted in 2016. One was for the El Paso Terminal 6-inch and 12-inch Holly Receipt and Storage Tank Project. The analysis focused on the addition of two incoming pipelines from Holly and included metering, proving, rack manifolds, and a new storage tank. A PHA was also conducted for the Crane Terminal Expansion. The scope of the study was the addition of a storage tank to accommodate current and future Longhorn crude product grades, including West Texas Sour (WTS), West Texas Intermediate (WTI), or crude condensate.

During 2016, eight incidents occurred at Longhorn facilities, three of which were small releases (less than 5 gallons), and thus not DOT-reportable. Four were minor incidents and four were hazard near-misses.

From the standpoint of facility data acquired for 2016, 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 ILI anomaly evaluations or remediation.[4]

In 2016, excavations were completed on 141 segments that did not have material documentation available. Magellan performed material testing on 75 of the 141 segments, 53%, meeting the 50% requirement.

5. 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, earth movement, TPD, SCC, and threats to facilities other than line pipe.

In 2016 an SMFL and deformation assessment was performed on an 8-inch refined product line between the Crane pump station and Odessa meter station. Five TFI assessments were run in December 2015 with results reported in 2016 between the Satsuma (MP 34.1) and Eckert (MP 227.9) pump stations. Table 3 lists the 2016 ILI assessments by pipeline segment.

[4] Per Section 9.3.3.3.1 of the Environmental Assessment for the Longhorn Pipeline Reversal, 2012

Table 3. ILI Assessments

Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley	Cedar Valley to Eckert	8" Crane to Odessa
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**	**457.5 to Odessa****
Corrosion					
TFI	TFI	TFI	TFI	TFI	SMFL
18-Dec-2015	16-Dec-2015	11-Dec-2015	8-Dec-2015	4-Dec-2015	10-5-2016
Pressure Cycle Induced Fatigue					
TFI	TFI	TFI	TFI	TFI	SMFL
18-Dec-2015	16-Dec-2015	11-Dec-2015	8-Dec-2015	4-Dec-2015	10-5-2016
Third-Party Damage					
					Deformation
					10-5-2016

*Note: the TFI assessments were run in December 2015 with final reports received in 2016.
**Odessa is located at MP 29.26 of Line 6648

5.1. Pressure-Cycle-Induced Fatigue Cracking

Pressure-cycle-induced fatigue-crack-growth of flaws is recognized to be a potential threat to the integrity of the Longhorn Pipeline. Manufacturing flaws in or immediately adjacent to the longitudinal electric resistance welded (ERW) or electric flash welded (EFW) seams of the 1950 line pipe material contained in the Existing Pipeline are considered to be the primary concern. The concern is that a flaw that initially may be too small to fail at the operating pressure will grow through fatigue cracking and become large enough to cause a failure if exposed to sufficient numbers of large pressure fluctuations. Accordingly, Section 3 of the ORAPM requires the monitoring of pressure cycles during the operation of the pipeline, calculating the worst-case crack growth in response to such cycles, and reassessing the integrity of the pipeline at appropriate intervals to find and eliminate potentially growing cracks before they become large enough to cause a failure of the pipeline.

Although the likelihood of such flaws being present in the newer 1998, 2010, 2012 and 2013 pipe material is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses were considered for the New Pipeline (MP 9 to East Houston, 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 and Spiral MFL tool runs from East Houston Station to Crane completed in 2014 and 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 (the basis for an initial flaw size from API 5L[5]). 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. Based on this information, 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[6] 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

[5] API Specification 5L, Forty-fifth Edition, Includes Errata, 2015
[6] API RP 579-1/ASME FFS-1, Fitness-For-Service, Third Edition, 6/1/2016

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. Kiefner will notify Magellan of the calculated date of failure, apply a safety factor, 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 outside diameter (OD), 0.312-inch wall thickness (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 2015 TFI tool run indicated 29 Seam Weld B features in the Buckhorn to Warda, Warda to Bastrop and Cedar Valley to Eckert, Cartman to Kimble, Kimble to James, Texon to Barnhart, and Crane to Texon segments. These 29 features were investigated and repaired in the 2016 dig program. Pursuant to the procedure in Section 3.4 of the ORA Process Manual, the detection threshold capabilities of the TFI tool were 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 Kiefner 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. This is used as the starting flaw 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 2016. The analysis was completed using the pressure data available from the most recent TFI or Spiral MFL inspection to December 2016.

The analysis showed that the shortest time to failure for a possible feature that could have been missed by the 2015 TFI tool run is 13.2 years (from August 11, 2015) at the location that is now the Texon 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 6.0 years (from August 11, 2015) is recommended based on the current operating pressures. An assessment would be required in 2021 for the Texon to Barnhart segment. Therefore, the detection threshold anomalies determine the appropriate reassessment intervals. Assessments for the other segments would be required between 2022 and 2238, as stated in Section 3.1. The pressure cycling frequency decreased in 2016 for all segments except the Satsuma to East Houston segment, when compared to 2015. This resulted in a longer time until reassessment for segments which were not assessed in 2015. Figure 5 displays the pressure cycles at the Texon Station discharge during 2016. Figure 6 displays the pressure cycles at the Texon Station discharge during 2015. These figures are representative of pressure cycling in the Crane to Satsuma segments.

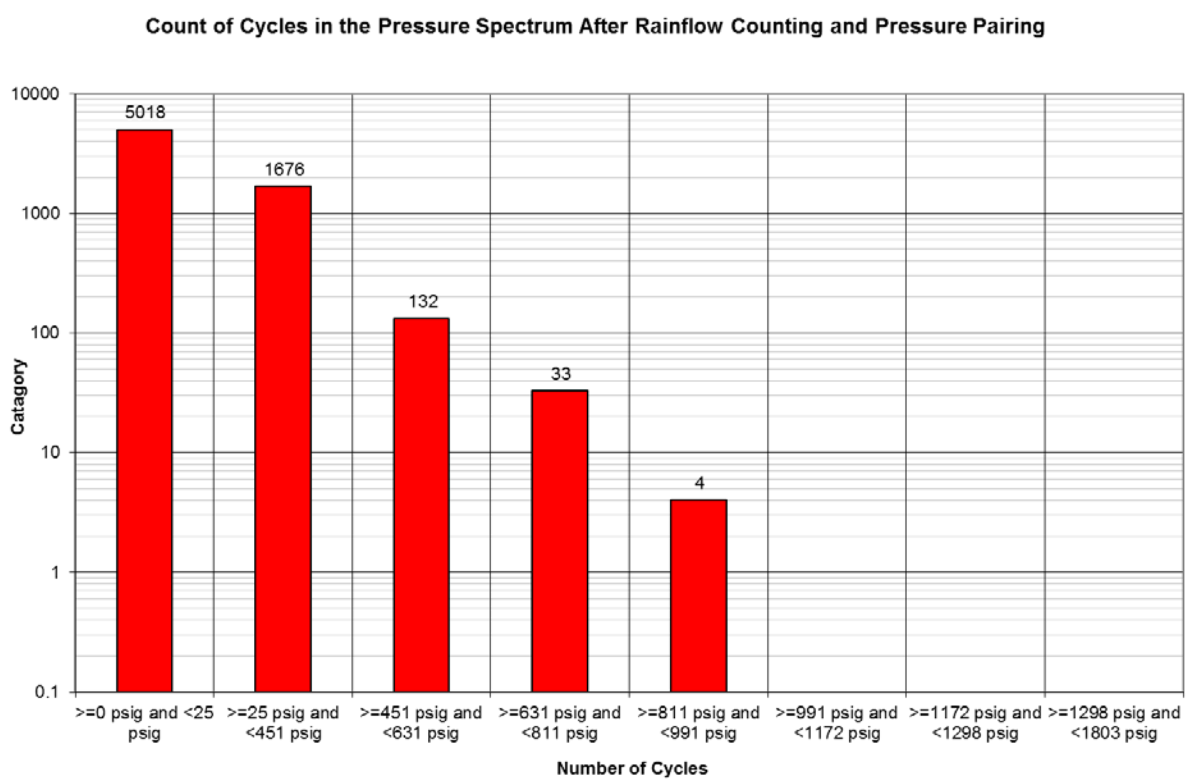


Figure 5. Pressure Cycles at Texon Station in 2016

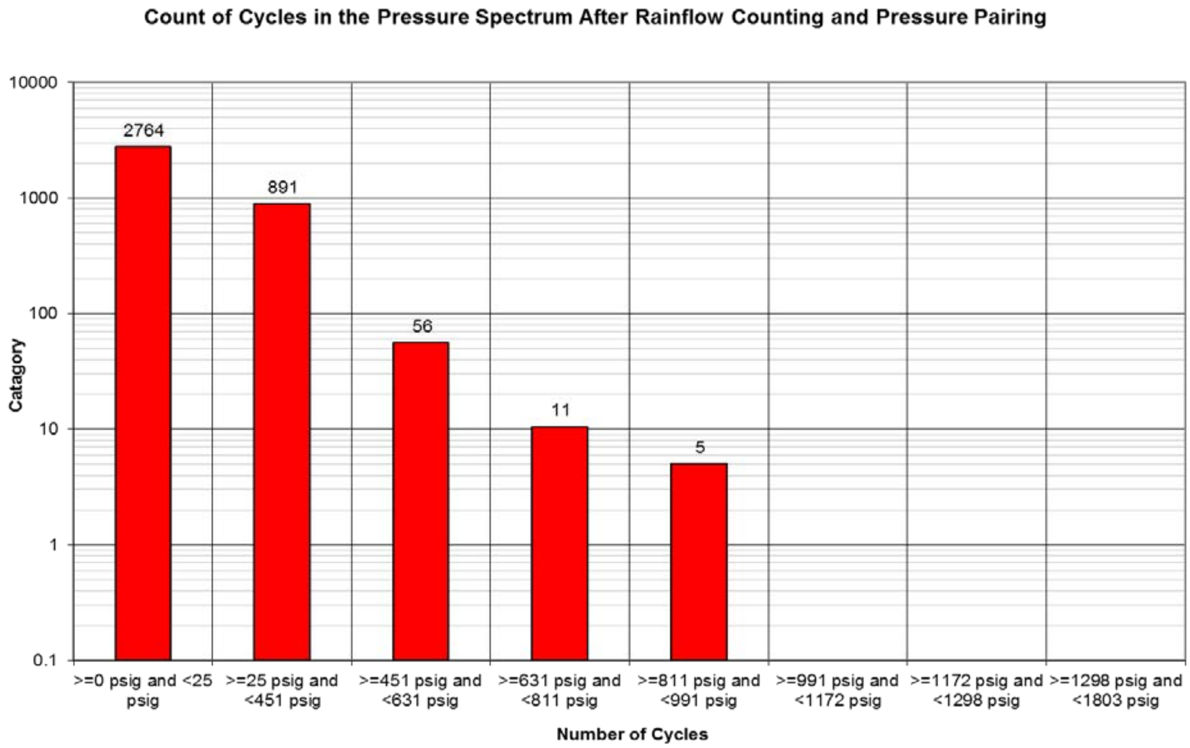


Figure 6. Pressure Cycles at Texon Station in 2015

Table 4 summarizes the locations evaluated. For the pipe between Crane Station and El Paso 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. The November 1, 2013 through December 31, 2016 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. For the pipe between the East Houston Station and Crane Station, the pressure data recorded after each segment's TFI ILI data were used in the analysis. For the pipe between East Houston Station and Speed Junction, the pressure data recorded after the line reversal was 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 419.4 years. This would result in a reassessment interval of a minimum of 188.9 years.

Table 5 depicts the fatigue life for each of the locations analyzed. 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 4. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations

Case	Description	Seam Type	Manufacturer	Station	Mile Post	Diameter, inches	Wall Thickness, inch	Pipe Grade
1	1998 in East Houston to Speed Junction	ERW-HF	U.S. STEEL	187+87	3.6	20	0.312	X52
2	1947 Pipe near Satsuma Discharge	ERW-LF	UNKNOWN	1799+54	34.1	20	0.312	Grade B
3	1950 Pipe near Buckhorn Discharge	EFW	A.O. SMITH	3587+73	67.9	18	0.281	45,000 SMYS
4	1950 Pipe near Warda Discharge	EFW	A.O. SMITH	5960+75	112.9	18	0.281	45,000 SMYS
5	1950 Pipe near Bastrop Discharge	EFW	A.O. SMITH	7487+53	141.8	18	0.281	45,000 SMYS
6	1947 Pipe at Cedar Valley Discharge	EFW	A.O. SMITH	8963+66	169.8	18	0.281	45,000 SMYS
7	1950 Pipe near Eckert Discharge	EFW	A.O. SMITH	12032+98	227.9	18	0.281	45,000 SMYS
8	1950 Pipe near James River Discharge	EFW	A.O. SMITH	13736+94	260.2	18	0.281	45,000 SMYS
9	1950 Pipe near Kimble Discharge	EFW	A.O. SMITH	15585+45	295.2	18	0.281	45,000 SMYS
10	1950 Pipe near Cartman Discharge	EFW	A.O. SMITH	18212+02	344.9	18	0.281	45,000 SMYS
11	1950 Pipe near Barnhart Discharge	EFW	A.O. SMITH	19354+32	366.6	18	0.312	45,000 SMYS
12	1953 Pipe near Texon Discharge	EFW	A.O. SMITH	21998+56	416.6	18	0.25	X52
13	1953 Pipe near Crane Crude Discharge	EFW	A.O. SMITH	24060+69	455.7	18	0.25	X52
14	1998 Pipe near Crane Products Discharge	ERW-HF	U.S. STEEL	24160+18	457.6	18	0.281	X65

Table 5. Fatigue Lives and Reassessment Intervals for Analysis Locations

Case	Cycles per Year	Date of Previous Assessment	Calculated Time to Failure from reversal date or 2014, 2015 TFI run date, years	Reassessment Interval, years	Reassessment Year
1	877	N/A	419.4	188.9	2202
2	4,067	10/1/2014	40.3	18.1	2032
3	2,132	12/18/2015	51.4	23.1	2039
4	2,073	12/16/2015	26.3	11.9	2027
5	2,316	12/11/2015	20.7	9.3	2025
6	1,914	9/19/2007	68.2	30.7	2046
7	1,926	3/22/2007	39.6	17.8	2033
8	4,080	8/19/2015	18.3	8.2	2023
9	3,573	9/1/2015	26.7	12.0	2027
10	3,754	8/28/2015	14.6	6.6	2022
11	3,091	8/24/2015	54.2	24.4	2040
12	3,346	8/11/2015	13.2	6.0	2021
13	2,949	7/17/2015	15.0	6.7	2022
14	585	N/A	> 500	> 225	>2238

5.2. 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 method is a valid approach for addressing line pipe corrosion.

In 2016, one MFL assessment was completed between Crane to Odessa and five TFI assessments were finalized between Eckert to Satsuma. A deformation tool accompanied the MFL tool run; deformations reported in the 2015 MFL assessments between Eckert to Satsuma were included in the 2016 TFI pipeline listings. Table 3 lists, by pipeline segment, the 2016 ILI assessments; mile posts are noted under each pipeline segment. Magellan will be performing additional remediation digs on the 2015 and 2016 MFL and TFI runs in 2017.

A run-to-run comparison was performed for external metal loss features reported by the MFL assessment on the Crane to Odessa segment. Only four data pairs (three external and one internal) were identified during the correlation of MFL assessments (2011 to 2016). This prevented calculation of external corrosion growth rates (CGRs) that could support confidence in a normal distribution. The TFI assessments were also correlated and resulted in 5,847 external data pairs. A CGR was not calculated using the TFI inspections due to the larger depth sizing specification of ±15% WT. The larger depth sizing gives more room for error in the data which makes it harder to get an accurate CGR. Data correlation and calculations were done using Kiefner's CorroSure software.

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 2007 TFI assessments and the 2016 TFI assessments can be seen in Figure 7 for Eckert to Satsuma. The histogram shows a spike in the 2016 data near MP 95.3. Previous MFL assessments were reviewed at this location and confirm that there has been metal loss reported on the same order of frequency magnitude that the 2016 TFI assessment is reporting.

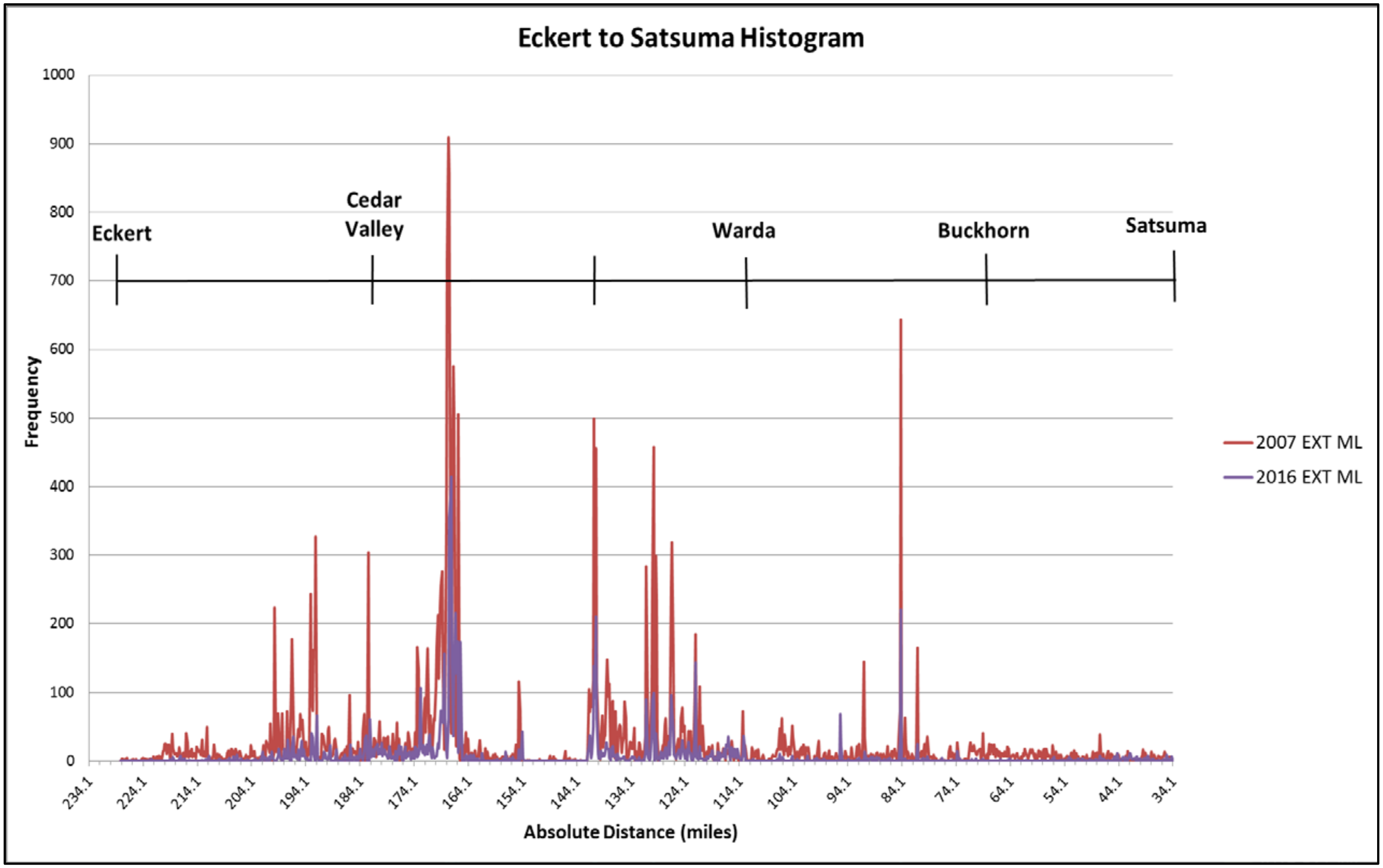


Figure 7. Eckert to Satsuma External Metal Loss Frequency by Linear Distance along the Pipeline (2007 TFI vs 2016 TFI Data)

Seam Weld Features

TFI seam weld features were also correlated and the results are shown in Table 6. Possible explanations for the difference in reported seam weld anomalies between 2007 and 2016 could be due to changes in tool technology, how features were reported, and repair of 2007 reported seam weld anomalies. GE reported that debris was present in isolated areas throughout the entire pipeline segment between Warda to Buckhorn and Eckert to Cedar Valley. GE stated that in areas where debris is located the sizing capability is reduced.

Table 6. Correlated Seam Weld Anomalies from TFI Assessments

Segment	2016 Seam Weld Anomalies	2007 Seam Weld Anomalies	Correlated Seam Weld Anomalies	Percentage Matched (%)
Eckert to Cedar Valley	111	876	55	49.5
Cedar Valley to Bastrop	271	201	48	23.9
Bastrop to Warda	74	109	28	37.8
Warda to Buckhorn	53	439	19	35.8
Buckhorn to Satsuma	88	343	62	70.5

ID Reductions

Magellan runs “Smart Geometry” tools (EGPs) to assess the threat of TPD and to monitor for possible hydrogen blistering. The ORA classifies ID reductions as a deformation of pipe diameter detected by the ILI tool. If an ID reduction is greater than or equal to 2% of the pipe diameter the ID reduction is referred to as a dent. If an ID reduction is less than 2% of the pipe diameter the ID reduction is referred to as a geometric anomaly.

The 2016 TFI assessment reports integrated information from the 2015 deformation tool runs. The information included from the 2015 deformation runs includes: 86 reported ID reductions, one of which was repaired in 2016 and 21 noted as being previously repaired. Of the remaining 64 ID reductions, 58 are classified as dents and six are classified as geometric anomalies. The dents break down as follows: 55 are located on the bottom 1/3 of the pipeline with depths that range from 2.0 to 4.0% OD and three are located on the top 2/3 of the pipe with depths that range from 2.0 to 3.2% OD.

The 2016 TFI assessments also included the following, from Eckert to Satsuma, 531 geometric anomalies with no associated depth, length, or width reported. ILI vendors will typically report geometric anomalies and correlate the reported geometric anomalies against the deformation reported features to verify geometric anomalies. For the 2016 TFI assessments, since a deformation tool was previously run in 2015 the reported geometric anomalies were not correlated against deformations by the vendor.

No dents were reported as interacting with seam welds, girth welds, or metal loss anomalies on the Eckert to Satsuma segments. Two dents were reported as interacting with a seam weld on the Crane to Odessa segment.

The Longhorn Pipeline System travels through a number of HCAs from James River to East Houston. As shown in Table 7, 38 of the dents are located within HCAs; however, these dents do not meet the current regulatory repair criteria (equal to or greater than 2% OD and interacts with a long seam or girth weld, or on the bottom of the pipe and with a depth greater than 6% OD).

Table 7. ID Reductions Located within HCAs [7]

Segment	Within HCA		
	Quantity	**Peak Depth (% OD)**	**Comment**
Buckhorn to Satsuma	0	N/A	• 1 dent reported; noted as repaired
Warda to Buckhorn	3	2.1%	• All 3 located on bottom 1/3 of pipe
Bastrop to Warda	3	2.3	• 1 dent noted as repaired • Two located on bottom 1/3 of pipe
Cedar Valley to Bastrop	0	N/A	
Eckert to Cedar Valley	29	3.4	• 7 dents are noted as repaired • 22 dents located on bottom 1/3 of pipe
Crane to Odessa	3	1.3	• One dent with a depth of 4.8% is noted as repaired • Two dents located on bottom 1/3 of pipe • One dent located on top 2/3 of pipe
Total	**38**		

[7] 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 evaluated using the ILI verification standard API 1163 Second Edition, April 2013. Section 7 and Section 8 of this standard describe methods 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. The standard defines results with and without field verification measurements. API 1163 Section 7 provides information on what the ILI vendor is to provide regarding pre-, mid-, and post-inspection checks for tool runs. API 1163 Section 8 describes a process for validating ILI measurements using three levels of validation.

The validation levels differ based on the risk of the pipeline segment and the amount of validation data. Validation Level 1, Level 2, and Level 3 could be described as a good, better, or best analysis approach. A Level 1 validation just looks at how the tool ran during the assessment; no statistical analysis is performed. A Level 2 validation builds on Level 1 by adding validation measurements: greater than or equal to five, but not statistically significant. Level 2 validations can be used to reject an ILI tool assessment. A Level 3 validation builds on the Level 1 and adds a statistically significant number of validation measurements which allows an as-run tool performance to be confidently stated.

The three levels of validation all consist of the following steps:

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

<u>Validation Level 1 (Annex C)</u>

- A comparison with large-scale historic data for pipeline segments similar to the pipeline being inspected (§8.2.3)

Validation Level 1 only applies to pipelines with anomaly populations that present lower risk of consequence or probability of failure. Typically there is only a limited number or no validation measurements taken on the pipeline being inspected. A Level 1 validation assumes the ILI specified tool performance is neither proven nor disputed for the ILI run. This assumption means the validity of the ILI run cannot be rejected solely based on a Level 1 validation. A Level 2 or Level 3 validation is required before an ILI run can be rejected.

<u>Validation Level 2 (Annex C)</u>

- A comparison with field excavation results warranted by the reporting of significant indications (§8.2.6)

Validation Level 2 applies to pipelines with a lower risk of consequence or probability of failure that have indications of significance reported by ILI. Typically there are enough validation measurements taken on the pipeline being inspected to confidently state whether the ILI tool is performing worse than the ILI specification and possibly reject the ILI run. However, a Level 2 validation does not let one confidently state that the ILI tool is performing within ILI specification. The number of validation measurements will be greater than or equal to five, but not statistically significant with which to perform a Level 3 validation. If the ILI tool specification can be rejected, then there is the option to progress to a Level 3 validation which may require additional validation measurements.

Validation Level 3 (Annex C)

- A comparison with field excavation results warranted by the reporting of significant indications (§8.2.3)

Validation Level 3 applies to pipelines with a higher risk of consequence or probability of failure that have indications of significance reported by ILI. Typically there are a statistically significant number of validation measurements taken on the pipeline being inspected to confidently state an as-run tool performance.

Depending on the analysis of the data using the API 1163 decision chart process, the tool performance can be rejected, accepted, or non-conclusive. 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.

For each assessment listed in Table 3, process verification and quality control was reviewed. The general results for all of the 2016 ILI assessments were 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:

- Channels 129 to 136 on the TFI tool failed on the Cedar Valley to Bastrop segment; these sensors equal 2.08% of the total sensors on the tool. GE notes detection and sizing of small features affected by this issue will be degraded.
- Channels 67 to 72 responded intermittently for a total of 9,681 ft on the Bastrop to Warda segment. GE notes within this area a total of 269 ft affected data along the seam weld; detection and sizing of seam weld features in these affected seam welds will be degraded.

- GE notes background noise was present in one of the four tool racks during the last 3.1 miles of the Warda to Buckhorn segment. The noise did not affect detection of features but may affect feature sizing.

In 2016, Magellan performed 154 in-ditch assessments associated with ILI anomaly investigations, of which 145 corresponded to the 2015 and 2016 ILI assessments. Material identification testing was completed at 75 (or 53%) of the investigation locations as 141 of the ILI anomaly locations did not have material documentation available. Table 8 shows, per pipeline segment, the breakdown of ILI investigation digs and material identification tests that were performed in 2016. Table 9 gives an overview of Positive Material Identification (PMI) testing since the requirement to perform PMI testing was added per the 2012 Longhorn Pipeline Reversal EA (Reference [6]). An overview of the ILI anomaly investigation dig results are listed in Table 10 for metal loss features, Table 11 for seam weld features, and Table 12 for deformation features.

Table 8. Summary of ILI Investigations in 2016

Pipeline Segment	Number of ILI Investigation Digs	Number of Material Identification Tests
8-in El Paso to Chevron	0	0
8-in Crane to Odessa	0	0
12-in El Paso to Kinder Morgan	0	0
18-in El Paso to Cottonwood	9	0
18-in Cottonwood to Crane	0	0
18-in Crane to Texon	15	7
18-in Texon to Barnhart	13	8
18-in Barnhart to Cartman	20	11
18-in Cartman to Kimble County	18	12
18-in Kimble County to James River	12	5
18-in James River to Eckert	14	3
18-in Eckert to Cedar Valley	9	6
18-in Cedar Valley to Bastrop	29	20
18-in Bastrop to Warda	10	3
18-in Warda to Buckhorn	4	0
18-in Buckhorn to Satsuma	1	0
20-in Satsuma to E. Houston	0	0
20-in E. Houston to Speed Junction	0	0
Total	**154**	**75**

Table 9. Positive Material Identification Testing Activity

Pipeline Segment	2014	2015	2016
8-in El Paso to Chevron	0	0	0
8-in Crane to Odessa	0	0	0
12-in El Paso to Kinder Morgan	0	0	0
18-in El Paso to Cottonwood	0	0	0
18-in Cottonwood to Crane	0	0	0
18-in Crane to Texon	0	1	7
18-in Texon to Barnhart	0	0	8
18-in Barnhart to Cartman	0	0	11
18-in Cartman to Kimble County	0	0	12
18-in Kimble County to James River	0	0	5
18-in James River to Eckert	0	1	3
18-in Eckert to Cedar Valley	1	0	6
18-in Cedar Valley to Bastrop	0	0	20
18-in Bastrop to Warda	0	1	3
18-in Warda to Buckhorn	0	2	0
18-in Buckhorn to Satsuma	0	0	0
20-in Satsuma to E. Houston	0	4	0
20-in E. Houston to Speed Junction	0	0	0
Total PMI Tests Performed	**1**	**9**	**75**
Segments without available Material Documentation	**2**	**18**	**141**
Percentage Addressed (Requirement of 50%)	**50%**	**50%**	**53%**

Table 10. Overview of 2016 ILI Field Investigation Metal Loss Data Correlations

Pipeline Segment	EXT ML to EXT ML	EXT ML to Lamination	EXT ML to Sloping Lamination	EXT ML to Planar Laminations	EXT ML to Lamination with Crack-like Indication	EXT ML to Surface Breaking Laminations	EXT ML to Mill or Grind Repair	EXT ML to Dent Associated with ML	EXT ML to Gouge	EXT ML to Wall Thickness Variation	EXT ML to Through Wall Crack-like Indication	INT ML to INT ML	INT ML to ID Lamination	INT ML to Mid-wall Lamination	INT ML to Wall Thickness Variation	EXT ML to INT ML	INT ML to EXT ML	Total Data Correlations
18-in El Paso to Cottonwood	0	0	0	0	0	0	0	0	0	0	0	16	0	0	0	0	0	**16**
18-in Crane to Texon	13	27	10	1	0	2	2	0	0	0	0	0	0	1	0	1	0	**57**
18-in Texon to Barnhart	21	2	13	0	1	0	0	2	0	0	1	0	0	0	0	0	0	**40**
18-in Barnhart to Cartman	33	0	4	4	0	0	8	3	0	0	0	0	0	0	0	0	0	**52**
18-in Cartman to Kimble County	14	3	23	0	0	0	0	0	1	0	0	1	0	0	0	0	0	**42**
18-in Kimble County to James River	4	2	0	0	0	0	1	0	2	3	0	8	1	2	0	0	0	**23**
18-in James River to Eckert	2	0	1	5	0	0	0	0	0	3	0	4	0	0	7	0	5	**27**
18-in Eckert to Cedar Valley	1	3	0	0	0	0	1	0	0	0	0	0	0	2	0	0	4	**11**
18-in Cedar Valley to Bastrop	125	8	0	1	0	0	0	0	0	0	0	0	0	0	0	4	0	**138**
18-in Bastrop to Warda	10	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	**12**
18-in Warda to Buckhorn	0	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	**8**
18-in Buckhorn to Satsuma	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1**
Total	**223**	**46**	**52**	**12**	**1**	**2**	**12**	**5**	**3**	**6**	**1**	**37**	**1**	**5**	**7**	**5**	**9**	**427**

*Note: the data correlations are between 2015/2016 TFI reported features and the 2016 in-ditch reported findings.

Table 11. Overview of 2016 ILI Field Investigation Seam Weld Anomaly Data Correlations

Pipeline Segment	SW Anomaly to SW Anomaly	SW Anomaly to Lack of Fusion	SW Anomaly to Geometry on SW	SW Anomaly to EXT ML on Seam Weld	SW Feature B to Inclusion	SW Feature B to Lack of Fusion	SW Feature B to SW Anomaly	SW Feature B to ID/OD Crack-like Indication	SW Feature B to SW Crack-like Indication	SW Feature B to Hook Crack	SW Feature B to Lamination	SW Feature B to Sloping Lamination	SW Feature B to SW Toe Geometry	SW Feature B to Mill Defect / Trim Tool Miss Edge	SW Feature B to High/Low Mismatch	SW Feature B to Dent on Seam Weld	Total Data Correlations
18-in El Paso to Cottonwood	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Crane to Texon	2	0	0	1	1	0	2	1	0	0	0	0	0	0	0	0	**7**
18-in Texon to Barnhart	0	0	0	3	0	0	0	1	0	0	0	0	0	0	0	0	**4**
18-in Barnhart to Cartman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cartman to Kimble County	0	0	0	0	0	1	1	0	1	1	0	0	0	0	1	0	**5**
18-in Kimble County to James River	1	1	0	0	0	1	1	0	0	0	0	0	1	0	0	0	**5**
18-in James River to Eckert	0	1	0	0	0	1	0	0	1	0	0	0	0	0	0	0	**3**
18-in Eckert to Cedar Valley	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	**2**
18-in Cedar Valley to Bastrop	0	0	1	1	0	2	0	0	0	0	0	0	0	1	0	1	**6**
18-in Bastrop to Warda	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	**1**
18-in Warda to Buckhorn	0	0	0	0	0	2	0	1	2	0	0	0	0	0	0	0	**5**
18-in Buckhorn to Satsuma	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	**3**	**2**	**1**	**5**	**1**	**7**	**3**	**5**	**4**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**38**

*Note: the data correlations are between 2015/2016 TFI reported features and the 2016 in-ditch reported findings.

Table 12. Overview of 2016 ILI Field Investigation Deformation Anomaly Data Correlations

Pipeline Segment	Dent w/ML to Dent w/ML	Dent to Dent w/ML	Dent w/ML to Dent	Dent to Dent	Dent to Dent w/Gouge	Dent to Possible Pop out during Depressurization	Dent with Ovality & High/Low Mismatch at GW	Dent to Dent Affecting SW	Total Data Correlations
18-in El Paso to Cottonwood	0	0	0	0	0	0	0	0	**0**
18-in Crane to Texon	0	0	0	0	0	0	0	1	**1**
18-in Texon to Barnhart	3	0	0	0	0	0	0	1	**4**
18-in Barnhart to Cartman	3	0	0	1	0	0	1	0	**5**
18-in Cartman to Kimble County	0	0	0	1	0	0	0	0	**1**
18-in Kimble County to James River	2	0	1	1	1	0	0	0	**5**
18-in James River to Eckert	5	0	0	9	4	1	0	0	**19**
18-in Eckert to Cedar Valley	1	1	0	0	0	0	0	0	**2**
18-in Cedar Valley to Bastrop	0	0	0	0	0	0	0	0	**0**
18-in Bastrop to Warda	0	0	0	0	0	0	0	0	**0**
18-in Warda to Buckhorn	0	0	0	0	0	0	0	0	**0**
18-in Buckhorn to Satsuma	0	0	0	0	0	0	0	0	**0**
Total	**14**	**1**	**1**	**12**	**5**	**1**	**1**	**2**	**37**

*Note: the data correlations are between 2015/2016 TFI reported features and the 2016 in-ditch reported findings.

The TFI tool performance analysis considered results from all assessments from Crane to Satsuma. Segments were also looked at individually (i.e. Cedar Valley to Bastrop) and compared to the overall result to see if any segment differed significantly from the whole. If a segment had less than five metal loss data pairs it was not considered for individual tool performance as there was not a statistically significant number of metal loss validation measurements.

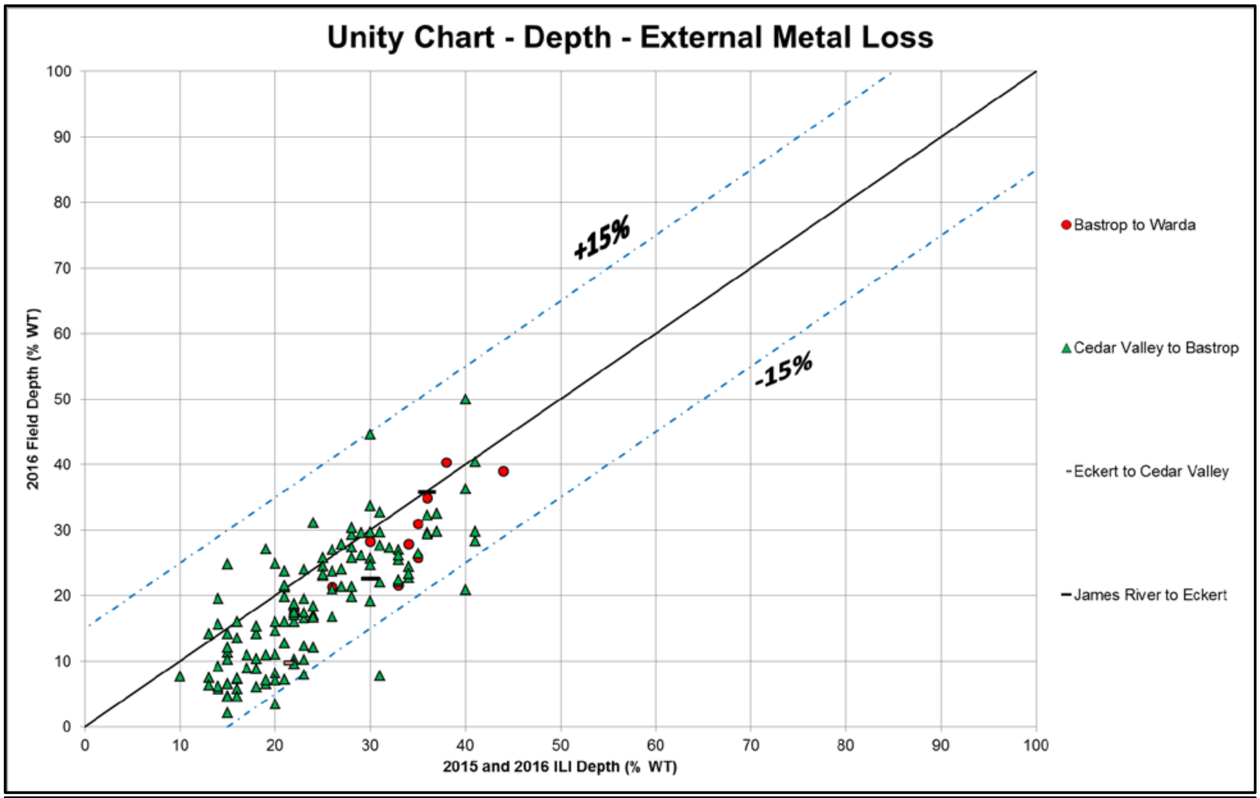
Correlation of the 2015 and 2016 TFI assessments and the 2016 dig results found in the ILI in-ditch investigation maintenance reports resulted in 501 correlated features. A breakdown of the dig results can be found in the preceding tables, Table 10, Table 11, and Table 12. The correlated data show that features reported by TFI as external metal loss (ML), assumed to be corrosion, were identified as external corrosion approximately 65% of the time in the field. The remaining 35% of investigated external ML were determined not to be external corrosion. These were laminations, wall thickness variations, gouges, prior grind repair, or mill defects. 122 different laminations were found in 42 of the ILI investigation digs and no laminations correlated with reported ILI ID reductions.

The 2016 field investigations resulted in 217 external metal loss data pairs from Crane to Satsuma; 209 of the metal loss data pairs were within the ±15% tool performance boundary. Figure 8 and Figure 9 show the in-ditch and ILI data pairs expressed as a unity plot. The unity plot shows that the TFI tool is over calling the depth on an average of 5.1% for correctly identified external metal loss features and on an average of 8.1% for correctly identified internal metal loss features.

A review of the correlated data was performed to determine if any correlation should be removed from further analysis. It is important to check the correlated data and remove correlations that are not metal loss to metal loss, as these results could skew the results. There were six correlated external metal loss features removed, four due to being reported in the field as internal metal loss interacting with a lamination, and two reported in the field evaluations with a general comment of “external metal loss less than 12.5% WT.”

A statistical analysis was performed to determine the average and standard deviation, and if outliers or extreme values were present. Extreme values have a low probability of occurrence on the order of 10^{-6} or less and should be noted with the reason for the occurrence. These values should be removed from the statistical analysis so that the results are not skewed. Outliers should be individually reviewed to determine the reason for the occurrence and if the data should remain incorporated within the statistical analysis. There were no correlated features that were noted or removed due to outliers or extreme values. The statistical analysis results are also shown in Table 13. Note that if the statistical analysis results in a negative value it represents that the ILI tool has under called the features when compared to the in-ditch data. Figure 10 demonstrates the difference between the ILI predicted and in-ditch depth based on a normal distribution for all correlated external metal loss features. Ideally, a cumulative fraction curve of 0.5 will be 0% WT as shown in ±15% WT for 80% of the data. The cumulative fraction curve for the best fit data shows that the ILI assessment has an overcall of approximately 5% WT. The curve is also showing a steeper slope which indicates that the tool appears to be performing better than specification if bias is accounted for. If the bias is accounted for, the tool is performing better than specification at ±7.9% WT. The best fit curves show a good fit to the correlated data with some deviation near the tails that indicated that there are some areas that are not normally distributed.

Review of the 2016 maintenance and NDE reports have brought about two recommendations to consider for future in-ditch anomaly investigations. The first recommendation is to use advanced NDE methodologies that have a high resolution for in-ditch evaluations to help characterize and size anomalies that are within the pipe body. In 2016, two NDE reports identified anomalies found in-ditch that are difficult for an ILI tool to detect and/or size. The second recommendation is if an in-ditch anomaly investigation discovers an anomaly that is difficult to characterize through non-destruction testing, then it is recommended to perform pipeline cutouts to allow for metallurgical investigation.



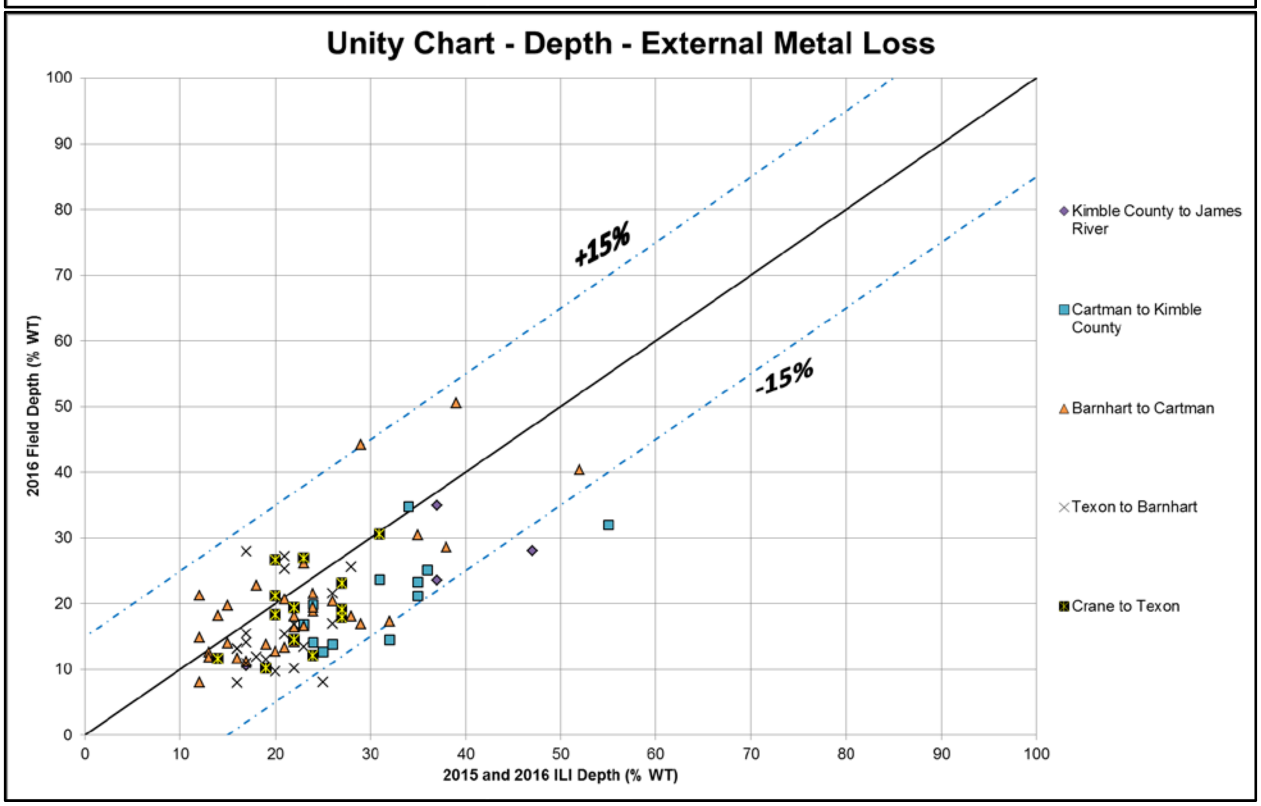


Figure 8. Unity Chart for Depth Verification for External Metal Loss (Upper Bound ±15% WT)

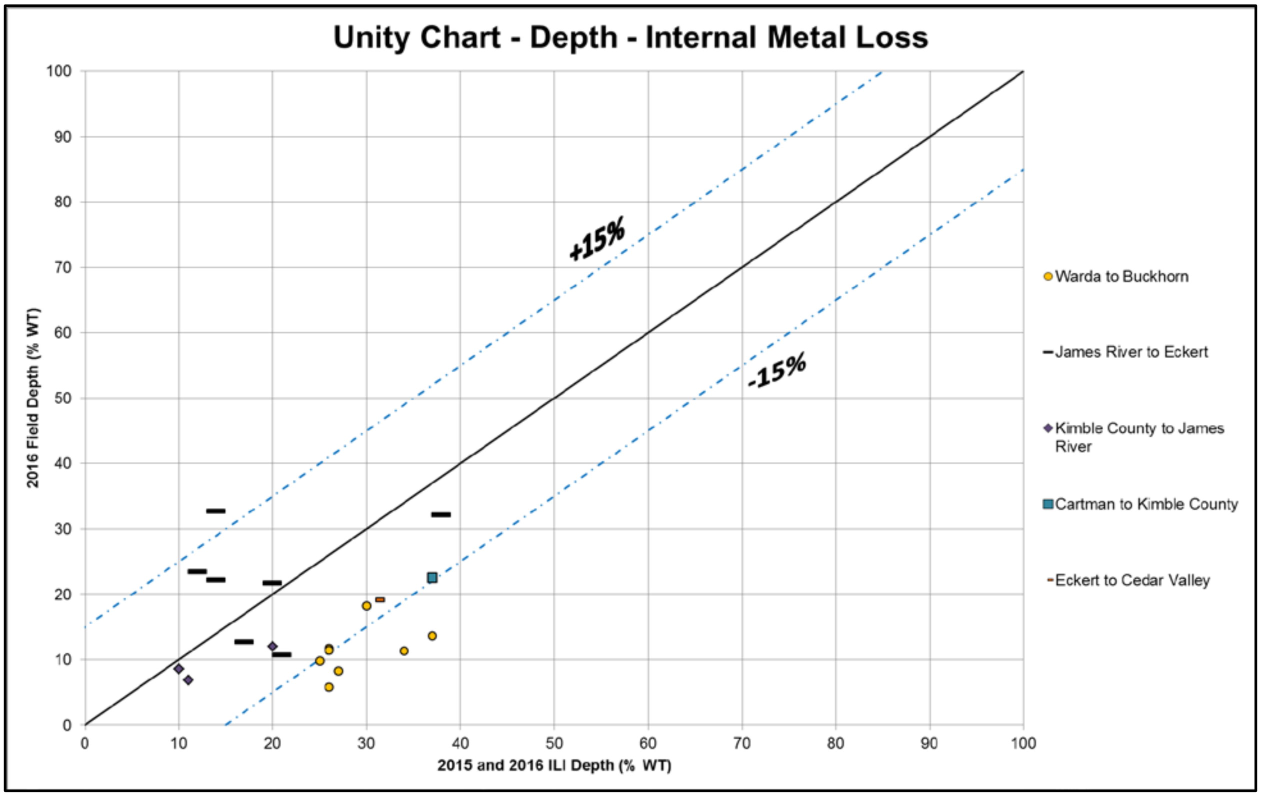


Figure 9. Unity Chart for Depth Verification for Internal Metal Loss (Upper Bound ±15% WT)

Table 13. Summary of Sizing and Population Density for External Metal Loss

	Overall – Crane to Satsuma	Bastrop to Warda	Cedar Valley to Bastrop	Cartman to Kimble County	Barnhart to Cartman	Texon to Barnhart	Crane to Texon
Number of features used in analysis	217	10	121	12	33	21	13
Total number of features	223	10	125	14	33	21	13
Average size difference	5.1% WT	4.6% WT	5.2% WT	10.7% WT	2.8% WT	4.8% WT	3.4% WT
Standard deviation	6.2% WT	3.9% WT	5.9% WT	6.2% WT	6.8% WT	6.3% WT	5.5% WT
Outliers	≤ -11.7% WT	≤ -5.8% WT	≤ -10.8% WT	≤ -6.1% WT	≤ -15.6% WT	≤ -12.0% WT	≤ -11.4% WT
	≥ 21.9% WT	≥ 15.0% WT	≥ 21.2% WT	≥ 27.5% WT	≥ 21.2% WT	≥ 21.6% WT	≥ 18.2% WT
Extreme Values	≤ -24.3% WT	≤ -13.6% WT	≤ -22.8% WT	≤ -18.7% WT	≤ -29.4% WT	≤ -24.6% WT	≤ -22.5% WT
	≥ 34.5% WT	≥ 22.8% WT	≥ 33.2% WT	≥ 40.1% WT	≥ 35.0% WT	≥ 34.2% WT	≥ 29.3% WT

Table 14. Summary of the TFI Tool Performance

	Overall – Crane to Satsuma	Bastrop to Warda	Cedar Valley to Bastrop	Cartman to Kimble County	Barnhart to Cartman	Texon to Barnhart	Crane to Texon
Tool Specification Depth Accuracy (% WT)	±15	±15	±15	±15	±15	±15	±15
# of successful measurements within the specified tool tolerance	209	10	118	10	32	20	13
# of total measurements taken	217	10	121	12	33	21	13
Lower Bound Probability (Agresti-Coull) (%)	93.9	79.8	94.4	62.64	88.5	82.7	83.7
Upper Bound Probability (Agresti-Coull) (%)	97.8	100.0	99.0	94.2	99.9	99.7	100.0

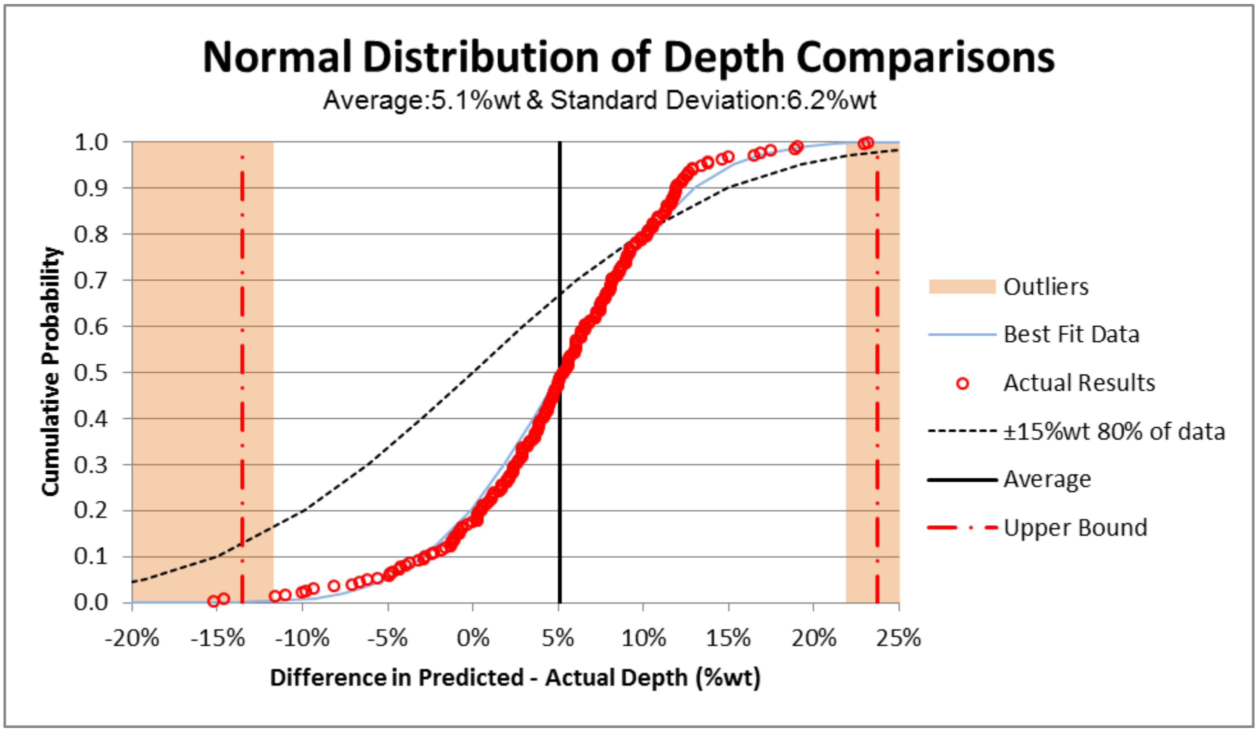


Figure 10. Normal Distribution Chart for the Difference between In-ditch and ILI Predicted Depths for 217 Data Pairs

5.3. Pipe Laminations and 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 2016 maintenance reports showed that laminations were the reason for one ILI investigation dig. Laminations were reported in 42 of the 154 in-ditch ILI investigation digs. No laminations found during in-ditch assessments were reported to be associated with a deformation or with blistering. ID reductions identified from the 2016 TFI assessments were aligned with the reported laminations from the 2010 UT assessments; monitoring these reported laminations for ID reductions may indicate the initiation of a hydrogen blister. No ID reductions correlated with laminations.

Continued monitoring of the lamination anomalies for the possibility of blister growth with ILI tools was recommended per the Longhorn Pipeline Reversal EA, Section 6.2.1.2.

5.4. Earth Movement (Fault and Stream Crossings)

Fault Crossings

The Longhorn Pipeline System crosses several aseismic faults between Harris County (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 original Longhorn Pipeline crosses four faults, including Akron, Melde, Breen, and Hockley, the location and geologic data of which are summarized in Table 15.

Table 15. 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
Note: Blank fields indicate that data was unavailable.

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-five subsequent displacement readings have been taken at approximately 6-month intervals. A plot of the vertical displacements over time is shown in Figure 11. Faults move in one direction only, so the up and down variability is an indication of the uncertainty of the measurement. Using nearly 13 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 over 12½ years for the Akron Fault and 0.019 in/yr over 12½ 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 11 readings taken as shown in Figure 12. The trend lines for the Negyev and Oates faults show no movement. At the McCarty Fault, there is a jump of about one-half inch between the baseline reading and the first reading point though no movement was observed from the readings after that. The jump at the first reading point is likely due to a false baseline reading.

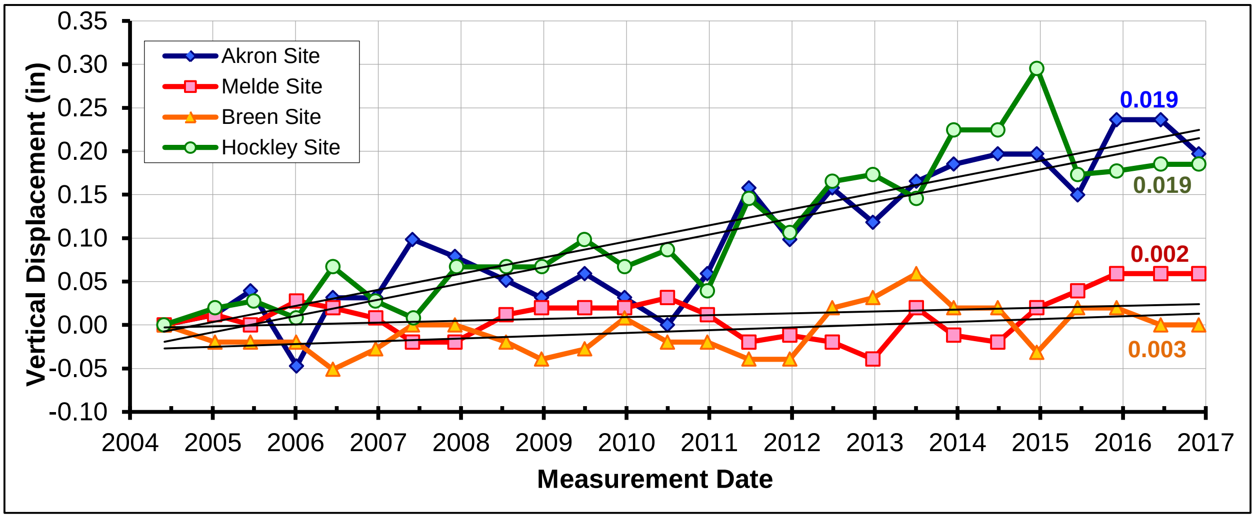


Figure 11. Fault Displacement over 13-Year Period at Akron, Melde, Breen and Hockley Faults

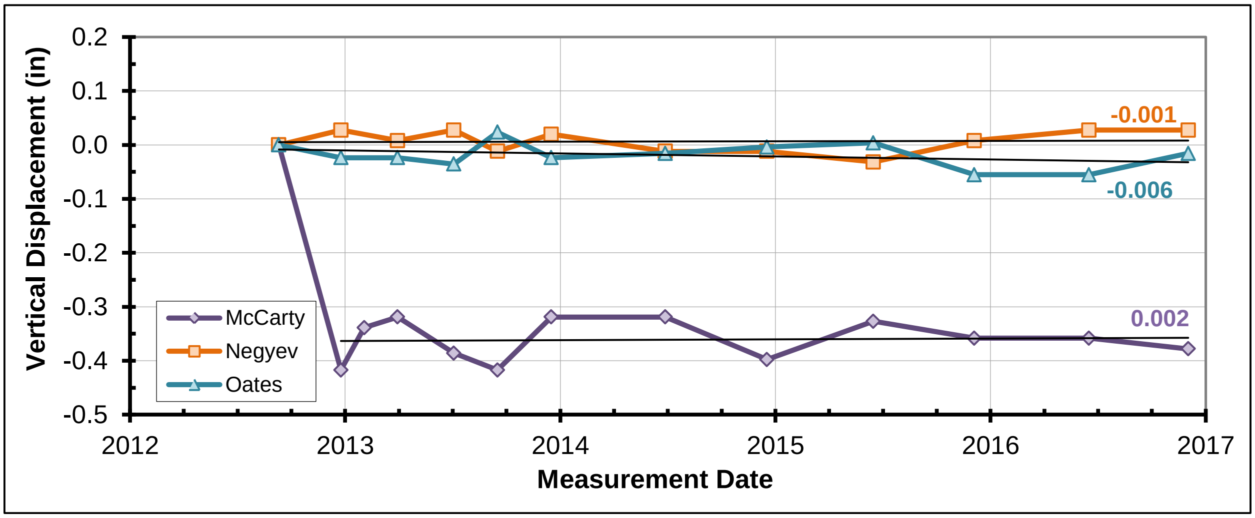


Figure 12. Fault Displacement over 4-Year Period for McCarty, Negyev and Oates

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[8] 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 a best estimate for representative values of obtainable properties; 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

[8] ASME B31.4-2002, Pipeline Transportation Systems for Liquids and Slurries, ASME Code for Pressure Piping, B31. The standard allows longitudinal stress up to 54% of SMYS.

also determined. Due to the high rate of movement and the relatively low allowable 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[9]. An important difference is that ASME B31.4 increased the allowable longitudinal stress level from 54% SMYS to 90% SMYS in 2012. The new allowable longitudinal stress level of 90% SMYS 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 of 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. Refer to the 2014 ORA Report for details of the analysis.

Table 16 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 11 and Figure 12. The calculated rate of displacement and reduced number of years to reach the allowed displacement are similar to the values in the 2015 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 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 were provided in 2014 ORA Annual Report and discussed in Section 3.4 of this report. The other six faults have more than

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

100 years to reach the allowable displacement. Such long time periods to reach a displacement 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 16. 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	222
Melde	4.13	0.002	1,937
Breen	1.50	0.003	471
Hockley	1.25	0.019	67
McCarty	0.95	0.002	625
Negyev	2.65	0.001	4138
Oates	2.65	0.006	476

* 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 EA (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 16. Actual measurements over the past 13 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.

Waterway Inspection

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. At other stream crossings, the pipeline has been buried very deep through horizontal directed drilling (HDD) and minimal risk of exposure is expected.

In the past, Magellan indirectly estimated the risk of pipe exposure at river crossings by surveying the erosion and movement of river banks two times each year. Starting in 2016, the survey of river banks was replaced by waterway inspections which directly measured the depth-of-cover (DOC) above the pipe under the river crossing. The waterway inspection was conducted by ONYX Service Incorporated (ONYX) at the Colorado River Crossing in July of 2016 and at the Pin Oak Creek Crossing in December of 2016. No pipeline exposures were found.

The Longhorn Pipeline crosses the Colorado River near MP 136 in Bastrop County, TX. During the inspection at this crossing, the width of the waterway was 210 feet and the maximum depth of the water was 4 feet. The pipeline was at least six feet below the bank of the river. At the river bottom, there is about a 100-foot long pipeline segment that has a DOC less than two feet near the west side with a minimum of 1.5 feet. The west bank has a steep cliff made out of concrete bags and articulated mats. The bags and mats were expanded into the river bottom and pass the centerline of the river. They were installed as a temporary protection against scour about 16 years ago. The east bank of the river is flat with a mud beach. The pipeline segment near the east bank has a DOC between two and four feet. The waterway inspection result in 2016 is very similar to that in 2015. No significant changes of pipeline DOC were found. An HDD has been scheduled to lower the pipeline at this crossing during April 2017. The pipeline would have sufficient cover to prevent future exposure after the HDD.

The Longhorn Pipeline crosses the Pin Oak Creek near MP 122.5 in Fayette County, TX. During the inspection at this crossing, the width of the waterway was 30 feet and the maximum depth of the water was 4 feet. The DOC was at least five feet at the bank of the creek. The minimum DOC of 2.25 feet was detected at the creek bottom near the creek centerline. The creek bottom consisted of soft mud. Magellan also provided an updated waterway inspection result at the Pin Oak Creek conducted in June 2015[10]. By comparing the inspection results, it revealed that there was no change in the pipeline position during the one and a half years. However, the contour of the creek bottom and bank evolved significantly and steps formed at the west bank, which indicated erosion. The minimum DOC at the creek bottom decreased from 2.8 feet in June of 2015 to 2.25 feet in December 2016. The pipe may become exposed in 2022 if the DOC decreases at this rate. The pipeline may be exposed earlier if events resulting in significant erosion occur during the time. Magellan should continue to perform waterway inspections at the current frequency to monitor the conditions and perform further remediation at the Pin Oak Creek if necessary, such as installing the pipeline deeper through HDD or placing a concrete mat at the river bottom to prevent scouring.

Flood Monitoring

The water surface was inspected daily and compared with the specified flood stage at three rivers, including the Colorado River, the Pin Oak Creek, and the Pedernales River. The monitoring site for the Colorado River is at Bastrop. No water surface exceeding the flood stage of 23 feet was reported in 2016. The monitoring site for the Pin Oak Creek is at Smithville. The water surface exceeded the flood stage of 20 feet by 4.43 feet on May 27, 2016

[10] The updated version of 2015 waterway inspection results at the Pin Oak Creek Crossing was provided to Kiefner by Magellan on July 7, 2017. It replaced the previous version provided by ONYX in which the elevations of the pipe were determined to be incorrect. The old version was reviewed in the 2015 Longhorn ORA.

and by 9.20 feet on May 28, 2016. The monitoring site for the Pedernales River is near Johnson City. The water surface exceeded the flood stage of 14 feet by 2.08 feet on June 2, 2016.

Magellan has committed to visually inspect the water crossings whenever a flood condition occurs.

Blasting

In November 2016, Erfurt Blasting Inc. conducted a series of blasting operations near the Longhorn Pipeline segment in Johnson City, TX.

Magellan conducted stress analyses via Battelle's model[11] with the assumption that the blasting was generated by 15 pounds of explosives per day 200 feet away from the pipeline. The resulting additional hoop stress due to blasting was calculated to be 1,239 psi. The sum of nominal hoop stress under actual operating pressure of 700 psig and the additional stress due to blasting was 21,432 psi, which is below the nominal hoop stress of 28,846 psi under the maximum operating pressure (MOP) of the pipeline at 1000 psig. Magellan then determined the influence of blasting to the pipeline was acceptable.

The blasting operation was also monitored by Ranger Excavating, LP in the field on November 17, 18 and 21, 2016. One monitor was placed on top of the Longhorn Pipeline at or near the location closest to the blasting center. The measured peak particle velocity (PPV) and the distance of the monitor to the blasting center are summarized in Figure 13. The figure shows that the closest blasting is beyond 650 feet from the pipeline and the maximum recorded PPV is 0.11 ips.

[11] McClure, G.M., Atterbury, T.V., and Frazier, N.A., "Analysis of Blast Effects on Pipelines", Journal of the Pipelines Division, Proc. of the American Society of Civil Engineers, November, 1964.

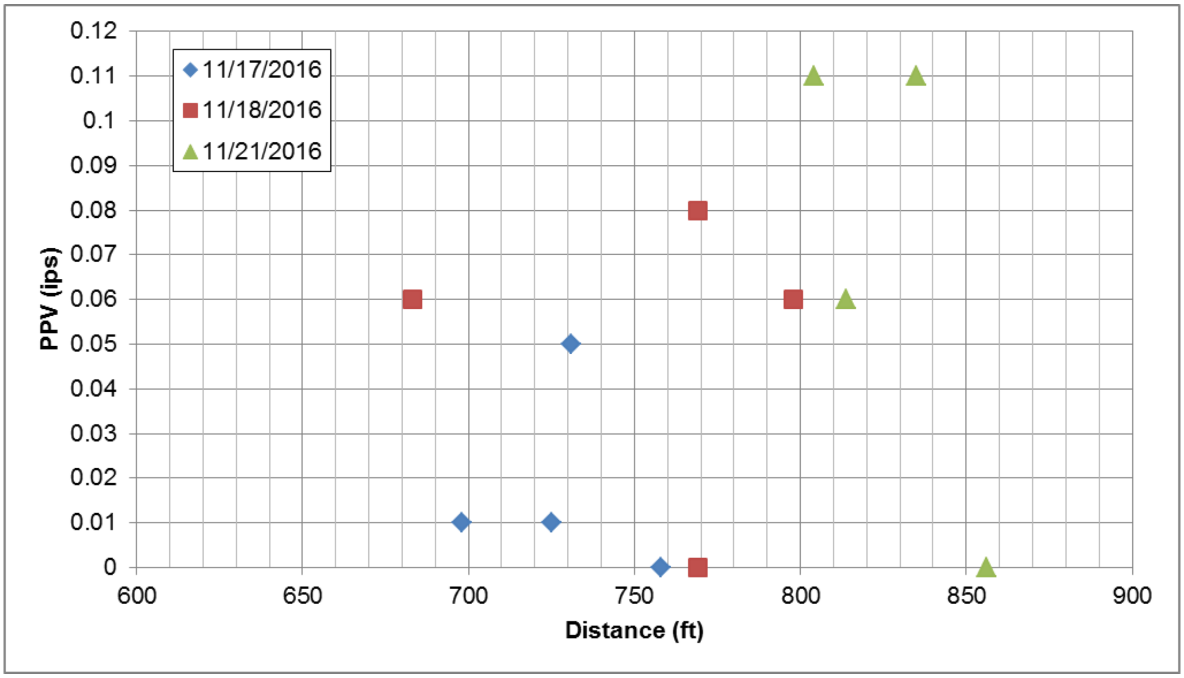


Figure 13. Measured PPV and Distance to the Blasting Center

Note the following comments with respect to the above analysis:

1) The stress analysis indicated the hoop stress due to the assumed blasting scenario plus that under actual operating pressure is still below the hoop stress resulting from the MOP. There is a considerable safety margin left at this stress level. When the wave of the ground vibration generated by blasting passed the buried pipes, it resulted in temporary ovalization in the pipeline cross section and through-wall bending. The stress due to through-wall bending is not considered as severe as the membrane stress, such as that generated by internal pressure. The reason is that under elastic conditions the peak bending stress only occurs at the outside surface of the pipe and varies linearly through the thickness. Therefore, ASME B31.4 allows the hoop stress including the through-wall bending component up to 90% of SMYS[12].

2) The recorded vibration indicated in the assumed blasting scenario was conservative. The assumed blasting of 15 pounds blasting at 200 feet from pipeline in the stress analysis is expected to result in a PPV at 0.29 ips[13]. Meanwhile, the recorded PPV is limited to 0.11 ips.

[12] Section 451.9 (a) in ASME B31.4.

[13] This PPV is estimated following $PPV = 160\left(R/\sqrt{W}\right)^{-1.6}$ with $R = 200\ \mathrm{ft}$ and $W = 15\ \mathrm{lbs}$ from Basters' handbook 17th Edition, ed. by Hopler, RB and International Society of Explosives Engineers.

3) A review the ILI indications in a 400-foot long pipeline segment nearest to the blasting site present four anomalies as listed in Table 17. The anomalies beyond this 400-foot segment are away from the blasting sites with negligible additional stress resulting from blasting. The most severe metal loss[14] in Table 17 is at 208.739 mile post with a depth of 23% pipe WT and a length of 6.46 inches. This metal loss results in a stress concentration factor of 1.14 at the local region following the modified ASME B31G. From item 1) above, the sum of hoop stress due to internal pressure and the additional hoop stress due to blasting is less than the nominal hoop stress at MOP with a design factor of 72%. Therefore, the maximum stress during blasting at the metal loss location should be less than 82% (=72%×1.14) of SMYS, which is well below SMYS and is acceptable.

Table 17. Anomalies in the 400-foot Long Segment Nearest to the Blasting Site

Calculated Mile Post (mile)	Feature Description	Peak Depth (%wt)	Length (in)	Width (in)	Orientation
208.739	External Metal Loss	23%	6.46	4.61	3:00
208.762	Geometric Anomaly affecting seam weld				11:45
208.770	External Metal Loss	16%	6.38	3.31	9:13
208.813	External Metal Loss	15%	4.65	1.97	9:07

Based on the above considerations, it was determined there was no damage to the Longhorn Pipeline from the blasting operation.

5.5. Third-Party Damage

The susceptibility of a pipeline to third-party excavation damage is dependent on characteristics such as the extent and type of excavation or agricultural activity along the pipeline ROW, the effectiveness of the One-Call System in the area, the amount of patrolling of the pipeline by the operator, the placement and quality of ROW markers, and the depth-of-cover over the pipeline. In all cases, different threats will exist at different locations along the pipeline.

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:

---

[14] No assessment was conducted for the geometric anomaly at mile post of 208.762 due to insufficient data. This anomaly was indicated by TFI tool from GE but not in the geometry tool report from TDW.

- 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, 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 2016 TPD Annual Assessment, Kiefner concluded:

- There were zero ROW near-misses and zero one-call violations.
- The 2016 TPD Annual Assessment shows a decrease of approximately 28% in the number of aerial patrol observations.

- There was an approximate 25% decrease in unique[15] aerial patrol observations, with a 38% decrease in third-party activity or non-company aerial-patrol-observations.
- The majority of aerial observations involved first and second party (Magellan and/or contractors under their control) versus third party observations (other pipeline operators, city utilities, landowners).
- One-call frequency increased approximately 5.5% and the number of tickets sent to Field Operations for clearing/locating increased by approximately 2.2% from 2015 to 2016.
- There was no ILI detected third-party damage.

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

No new exposures were identified in 2016. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the System Integrity Plan (SIP) were repaired after additional erosion was found. There was no third-party damage found at any of the remediated locations.

One-Call Violation Analysis

There were zero one-call violations during 2016. Of 17,562 one-calls in 2016, it appeared that 18% 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 9,148 (52%) of the one-call tickets. Travis County (Austin) accounted for 4,490 (26%) 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 868 tickets (5%).

Magellan should continue to ensure all relevant data are recorded on the incident data reports 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:

- Galena Park to the Pecos River (Tier-II and Tier-III areas)[16]:

[15] Unique observations refer to first and second party.

    - o Every 2.5 days, not to exceed 72 hours
- Pecos River to El Paso Terminal (Tier-I areas):
    - o Once a week, not to exceed 12 days, but at least 52 times per year
- Edwards Aquifer Recharge Zone (MP170.5-MP173.3):
    - o 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 2016 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.

5.6. 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 has performed investigative digs each year for three years in areas that could be most 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. In 2016 Magellan performed 154 ILI investigation digs and during each dig, the exposed pipe surface was checked for SCC using magnetic particle testing. No SCC has been found.

5.7. 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:

[16] Note that the patrol now includes E Houston to 9th Street Junction.

- 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 three pipeline facilities during 2016: Crane, Barnhart, and El Paso Terminal. No 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) and that the change be assessed to ensure that the appropriate risk mitigation levels on the system are maintained.

A Process Hazard Analysis (PHA) was performed on the El Paso Terminal and the Holly Receipt and Storage Tank Project. The analysis focused on the addition of two incoming pipelines from Holly and included metering, proving, rack manifolds, and a new storage tank.

A PHA was also conducted for the Crane Terminal Expansion. The scope of the study was the addition of a storage tank to accommodate current and future Longhorn crude product grades, including WTS, WTI, or crude condensate.

All eight incidents in 2016 occurred at facilities. Four were minor[17] and four were hazard near-misses. There were three releases which were not DOT-reportable because they were confined to company property, cleaned up promptly and were less than five gallons.[18] Four of the facility incidents involved human error, which were due to procedures not being followed and/or drawings not maintained accurately.

---

[17] A minor incident as defined in the LMP: 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 workdays cases; Citations under $25,000
[18] Per 49 CFR 195.5, Reporting Incidents

From the standpoint of facility data acquired for 2016, one can conclude that active non-pipe facilities had no adverse impact on public safety.

6. 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 of 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 2016 is evaluated below.

6.1. 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:

- <u>Number of miles of pipelines inspected by aerial survey and by ground survey (by pipeline segment) in a 12-month period</u>. This metric is compared to the previous 12-month periods. The goal is 100% of the commitment. Magellan met this commitment in 2016.

- <u>Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period</u>. 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 being replaced or repaired in future years, and this decline will not indicate any failing on the part of Magellan. On the other hand, tracking the replacement or repair of signs by pipeline segment may indicate third-party vandalism or carelessness in certain segments of the system which could be used as a leading indicator that additional public education might be needed in that region of the pipeline route.

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

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

Table 18 provides a summary of the LPSIP Activity Measures from 2005 through 2016.

Table 18. LPSIP Activity Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
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	173,996
No. of warning or ROW identification signs installed, replaced, or repaired		979	732	237	536	460	291	76	66	539	266	130	315
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	15
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	4,745
	Tier II	6,881	7,874	7,852	7,059	4,265	4,265	4,415	4,415	6,370	7,641	9,183	9,706
	Tier III	1,498	1,617	1,653	1,459	833	833	918	918	1,312	1,554	3,167	3,111

6.2. 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 2016 are presented in Table 19.

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 downward trend in immediate anomalies found per mile. In 2016 there were no immediate conditions as defined by the LPSIP and 49 CFR 195.452. The 2016 results follow a similar trend to recent years (2009-2015) where no immediate conditions had been reported. The monitoring and excavation program should continue to address significant reported anomalies.

No MFL reported metal loss features met POE evaluation dig requirements in 2016. POE calculations should continue to be performed.

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 19. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of immediate ILI anomalies per mile pigged		0.029	0.0203	0.038	0.004	0	0	0	0	0	0	0.004	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification.	Tier I	NA	0.0212	0.035	0.006	0	0	0	0	0	0	0	0
	Tier II	NA	0.0208	NA	NA	0	0	0	0	0	0	0.004	0
	Tier III	0.192	NA	0.003	NA	0	0	0	0	0	0	0	0
Total number of anomalies per hydrotest		NA	NA	NA	NA	NA	NA	NA	NA*	NA**	NA**	NA**	0
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~	0

* Hydrostatic tests were performed for pipeline commissioning purposes.
**No hydrotests were performed during 2014. 2015, or 2016.
~POE calculations only performed on the MFL assessments; the number of POE evaluations per mile pigged did not include the TFI mileage.

6.3. 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 20. Response times, volumes, and costs are for DOT-reportable leaks.

Table 20. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of leaks (DOT reportable)		2	0	1	3	0	1	2	0	2	2	0	0
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	NA
	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA
Average product volume released per incident	Tier I	5.7 bbls	0	5.7 bbls	0.4 bbls	0	0.4 bbls	1.2 bbls	NA	0.47 bbls	2.74 bbls	0	NA
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0	NA
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	NA
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0	NA
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50	< $50	NA	> $100k	< $25	0	NA
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50	< $25	NA	< $25k < $50k > $100k	< $25	0	NA
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	2
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0	0	2	0	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	0
Number of service interruptions		115	165	155	74	16*	17	9	8	15	15	11	8

7. Integration of Intervention Requirements and Recommendations

7.1. 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 and hydrogen blisters, 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 (EGP) 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. 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 caused 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 longitudinal 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 committed to run the UT tool to inspect for laminations and blisters. The UT tool can also characterize corrosion and has capabilities for detecting mechanical damage. The commitment was to perform a UT five years after startup and at intervals established by the ORA. 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 21 is a compilation of the tools run to date on the crude system 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 and third-party damage are based on the most recent inspection date; corrosion 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 21 because it is currently addressed using surface surveys rather than ILI technology.

Table 22 presents the completed ILI runs and planned inspections for the refined system.

Table 21. Completed ILI Runs and Planned Future ILI's for Longhorn Crude System

	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
Mileage	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
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
Date of Tool Run		21-May-06		21-Jul-06		2/15/2007
Tool	TFI	TFI		TFI		TFI
Date of Tool Run	6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07
Tool	SMFL	MFL	MFL			
Date of Tool Run	1-Oct-14	18-Dec-14	16-Dec-14			
Tool				MFL	MFL	MFL
Date of Tool Run				11-Jan-15	10-Jan-15	27-Mar-15
Pressure Cycle Induced Fatigue						
Tool	TFI ‡	TFI ‡		TFI ‡		TFI ‡
Date of Tool Run	6-Jul-07	20-Dec-07		19-Sep-07		22-Mar-07
Tool		TFI	TFI	TFI	TFI	TFI
Date of Tool Run		18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15
Tool	Def.					
Date of Tool Run	10-Jun-04					
Tool		Deformation		Deformation		
Date of Tool Run		21-May-06		21-Jul-06		
Tool	Def.	Deformation		Deformation		Def.
Date of Tool Run	5-Oct-07	15-Dec-07		16-Oct-07		15-Feb-07
Tool						
Date of Tool Run						
Tool	Def.	Deformation		Deformation		
Date of Tool Run	11-Sep-09	12-Oct-09		16-Dec-09		
Tool						Def.
Date of Tool Run						25-Jan-10
Tool	Def.	Deformation		Deformation		Def.
Date of Tool Run	7-Jun-12	7-Jun-12		9-Jun-12		15-Jun-12
Tool	Def.					
Date of Tool Run	22-Jun-13					
Tool	Def.					
Date of Tool Run	1-Oct-14					
Tool		Def.	Def.	Def.	Def.	Def.
Date of Tool Run		18-Dec-14	16-Dec-14	11-Jan-15	10-Jan-15	27-Mar-15
Next Required Assessment						
Corrosion	1-Oct-19	18-Dec-19	16-Dec-19	11-Jan-20	10-Jan-20	27-Mar-20
Pressure-Cycle Induced Fatigue	2032	2039	2027	2025	2046	2033
Third-Party Damage	1-Oct-17*	18-Dec-17*	16-Dec-17*	11-Jan-18*	10-Jan-18*	27-Mar-18*

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.
* 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.

	Eckert to Ft McKavett			Ft McKavett to Crane		
	Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
Mileage	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			MFL		
Date of Tool Run	19-Dec-06			12-Oct-06		
Tool	TFI					
Date of Tool Run	9-Nov-07					
Tool				TFI		
Date of Tool Run				8-Jan-08		
Tool	TFI	TFI	TFI	TFI	TFI	TFI
Date of Tool Run	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
Pressure Cycle Induced Fatigue						
Tool	TFI ‡					
Date of Tool Run	9-Nov-07					
Tool				TFI		
Date of Tool Run				8-Jan-08		
Tool	TFI	TFI	TFI	TFI	TFI	TFI
Date of Tool Run	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
Third-Party Damage						
Tool	Deformation			Deformation		
Date of Tool Run	19-Dec-06			12-Oct-06		
Tool				Deformation		
Date of Tool Run				21-Dec-07		
Tool	Deformation					
Date of Tool Run	23-Jan-08					
Tool	Deformation			Deformation		
Date of Tool Run	27-Mar-10			5-Aug-10		
Tool	Deformation			Deformation		
Date of Tool Run	17-Jun-12			1-Jul-12		
Tool	Def.	Def.	Def.	Def.	Def.	Def.
Date of Tool Run	6-Aug-15	4-Aug-15	31-Jul-15	25-Jul-15	19-Jul-15	18-Jun-15
Next Required Assessment						
Corrosion	19-Aug-20	1-Sep-20	29-Aug-20	24-Aug-20	11-Aug-20	17-Jul-20
Pressure-Cycle Induced Fatigue	2023	2027	2022	2040	2021	2022
Third-Party Damage	6-Aug-18*	4-Aug-18*	31-Jul-18*	25-Jul-18*	19-Jul-18*	18-Jun-18*

‡ 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

* 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 22. Completed 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	8" El Paso Kinder Morgan	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**	**0 to 9.4**	**0 to 9.4**
Assessments	**Corrosion**							
	Tool			MFL				
	Date of Tool Run			4-Nov-06				
	Tool			MFL	MFL	MFL	MFL	MFL
	Date of Tool Run			7-Mar-07	6-Mar-07	6-Mar-07	8-Mar-07	7-Mar-07
	Tool	MFL	MFL				Out of service between 2007 and 2012	
	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					MFL	
	Date of Tool Run	19-Nov-13					28-Jan-14	
	Tool			SMFL				
	Date of Tool Run			5-Oct-2016				
	Third-Party Damage							
	Tool			Deformation				
	Date of Tool Run			4-Nov-06				
	Tool	Deformation	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	8-Mar-07	7-Mar-07
	Tool	Deformation	Deformation				Out of service between 2007 and 2012	
	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			Deformation				
	Date of Tool Run			5-Oct-2016				
Next Required Assessment								
	Corrosion	19-Nov-18	19-May-17	5-Oct-2021	23-Feb-17	21-Feb-17	28-Jan-19	22-Feb-17

	Crane to Cottonwood	Cottonwood to El Paso	Crane to Odessa	8" El Paso to Chevron	8" Kinder Morgan Flush Line	8” El Paso Kinder Morgan	12" El Paso to Kinder Morgan
Pressure-Cycle Induced Fatigue	2226	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*	*Not susceptible*	*Not Susceptible*
Third-Party Damage	21-Nov-18	19-May-17	Oct-5-2019	23-Feb-17	21-Feb-17	28-Jan-19	22-Feb-17

7.2. 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 9th Street Junction to El Paso is under DOT jurisdiction as well as the four laterals connecting El Paso to Diamond Junction.

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 west 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.

7.3. 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 have been no pipe replacements since the reversal.

8. SUMMARY OF RECOMMENDATIONS

The following table provides a summary of recommendations from the 2016 ORA.

Table 23. Summary of 2016 Recommendations

Topic	Recommendation	ORA Section
In-line Inspection	Advanced NDE methodologies, such as Automated UT (AUT), that have a high resolution are recommended for in-ditch evaluations to help characterize and size complex anomalies that are within the pipe body. Kiefner recommends that Magellan consider pipeline cutouts to allow for metallurgical investigation if an in-ditch anomaly is difficult to characterize through non-destructive testing. Kiefner recommends that Magellan continue to look into advanced technology that will help assess interacting threats such as: dents with metal loss, dents with mechanical damage or gouges, and laminations with metal loss or denting. It is recommended that the advanced technology be incorporated into the regular assessment intervals.	Executive Summary
Earth Movement – Faults	The current six-month monitoring practice is recommended for the Hockley 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 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.	3.4
Stream Monitoring	Continue monitoring at current frequency and perform further remediation at the Pin Oak Creek if necessary. Examples include installing the pipeline deeper through horizontal directional drilling (HDD) or placing a concrete mat at the river bottom to prevent scouring.	3.4

REFERENCES

1. Kiefner, J. F. and Mitchell, J. L., "Charpy V-Notch Impact Data for Six Samples of Seam-Weld Material from the Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 06-6 to Longhorn Partners Pipeline Company, (January, 19, 2006).
2. Kiefner, J. F., Johnston, D. C., and Kolovich, C. E., "Mock ORA for Longhorn Pipeline", Kiefner and Associates, Inc., Final Report 00-49 to Longhorn Pipeline Partners, LP (October 16, 2000).
3. Kiefner, J. F., Kolovich, C. E., Zelenak, P. A., and Wahjudi, T. F., "Estimating Fatigue Life for Pipeline Integrity Management", Paper No. IPC04-0167, Proceedings of IPC 2004 International Pipeline Conference, Calgary, Alberta, Canada (October 4-8, 2004).
4. Verbeek, E.R., Ratzlaff, K.W., Clanton, U.S., Faults in Parts of North-Central and Western Houston Metropolitan Area, Texas, U.S. Geological Survey, September 2005.
5. Environmental Assessment, Appendix 9E, Longhorn Mitigation Plan Mandated Studies Summaries.
6. Final Environmental Assessment of the Longhorn Pipeline Reversal, PHMSA-2012-0175, December 2012.

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 ORA, 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 LPSIP at Sec. 3.5.2 and the associated ORA at Sec. 4.0.	Within 3 months of startup and thereafter at such intervals as are established by the ORA	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 LPSIP at sec. 3.5.2 and the associated ORA at Sec. 4.0.	At such intervals as are established by the ORA, 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 LPSIP at Sec. 3.5.2 and the associated ORA at Sec. 4.0.	At such intervals as are established by the ORA, 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 LPSIP, 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 LPSIP, 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 ORA, 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 ORAPM 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 2016.

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 eight additional 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 2016.

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

Milepost	Facility Name	Tier	Elevation, feet	
			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 during 2016.

Mill Inspection Defect Detection Threshold (Item 13)

Magellan reviewed the documentation for each pipe segment covered by the 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[5], 5LX[19], or 5LS[20]. 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. CVN 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 in the following table:

[19] API Standard 5LX, Specification for High-Test Line Pipe
[20] API Standard 5LS, Specification for Spiral-Welded Line Pipe

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 2016.

B.2. Operating Pressure Data

For Items 21, 22, and 23, Kiefner has received pressure and flow data for Galena Park[21], East Houston, Satsuma, Cedar Valley, Kimble County, Crane, and El Paso Pump Station since September 17, 2004. From November 1, 2013 to December 31, 2016 pressure and flow data have also been received for Texon, Barnhart, Cartman, James River, Eckert, Bastrop, Warda, and Buckhorn Pump Stations. From September 1, 2016 to December 31, 2016 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.

[21] Galena Park is no longer part of the Longhorn Pipeline System.

B.3. ILI Inspection and Anomaly Investigation Reports

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

A total of 202 maintenance reports were received for evaluations completed in 2016. Anomaly investigations were complete in 154 of the 202 maintenance reports. Anomaly investigations also included nondestructive evaluation (NDE) reports with detailed investigation results. PMI reports were available for 75 of the 154 anomaly investigation reports. 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 ILI anomalies were excavated per segment. In Table B-3b the total number of anomalies addressed includes the targeted ILI anomalies for each dig and any anomaly found in the area of repair for that associated dig.

Table B-3a. Remediations per Maintenance Reports Completed in 2016

	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*									12/4/15*	12/8/15*	12/11/15*	12/16/15*	12/18/15*					10/5/16
Maintenance Report	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No	Yes
Tier I	17	12	0	0	0	0	2	10	5	15	4	11	0	0	0	0	0	4
Tier II	0	0	18	13	21	18	12	5	6	15	8	1	1	0	0	0	0	0
Tier III	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0
Total Digs	17	12	18	13	21	18	14	17	13	30	12	12	1	0	0	0	0	4
HCA	0	5	0	0	0	0	1	3	3	20	1	0	0	0	0	0	0	0
Non-HCA	17	7	18	13	21	18	13	14	10	10	11	12	1	0	0	0	0	4

*TFI assessment: final reports were received in 2016.

Table B-3b. Reported Anomalies Excavated per the 2016 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	633	0	0	78	52	53	48	13	12	5	332	39	0	1	0	0	0	0	0
Int Metal Loss	85	20	0	0	0	0	3	14	26	0	0	0	22	0	0	0	0	0	0
Mill Anomaly w/Metal Loss	5	0	0	1	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0
Lack of Fusion External	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Mid-wall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Internal	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	18	0	0	0	2	2	1	2	10	1	0	0	0	0	0	0	0	0	0
ID Reduction w/associated metal loss	13	0	0	0	3	4	0	3	3	0	0	0	0	0	0	0	0	0	0
ID Reduction affecting pipe curvature at seam weld	11	0	0	1	1	0	0	0	9	0	0	0	0	0	0	0	0	0	0
Girth Weld Anomaly	0	0	0	0	0	0	0	0	0	0	0	0	0	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	1	0	0	0	0	0	0	0	0	1	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
Seam Weld Feature B	29	0	0	4	1	0	5	3	0	5	4	1	6	0	0	0	0	0	0
Seam Weld Anomaly	15	0	0	3	6	0	0	2	1	0	3	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	2	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Ext Metal Loss Crosses Long Seam	6	0	0	3	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0
TOTAL	**820**	**20**	**0**	**92**	**66**	**60**	**57**	**37**	**61**	**16**	**342**	**40**	**28**	**1**	**0**	**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.

B.4. Hydrostatic Testing Reports

Hydrostatic Leaks and Ruptures (Item 75)

No hydrostatic tests were performed on the Longhorn Pipeline System during 2016.

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 correlation of MFL assessments (2011 to 2016) for the Crane to Odessa segment resulted in four data pairs (three external and one internal). External CGRs were not calculated due to too few data pairs available to support confidence in a normal distribution. The TFI assessments were also correlated and resulted in 5,847 external data pairs. External CGRs were not calculated for the TFI inspections due to the large range in tool performance +/-15% WT.

Internal Corrosion Coupon Results (Item 37)

Internal corrosion coupon reports were reviewed at 12 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 12 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; the 16-inch Plains WTI Delivery 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 and one coupon was reported as being lost in the pipeline. 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								
16	Crane	Advantage – Delivery to Crane	N0184	12/29/2015	5/1/2016	124	-0.01	
16	Crane	Advantage – Delivery to Crane	S7894	5/1/2016	9/1/2016	123	0.00	
16	Crane	Advantage – Delivery to Crane	S7914	9/1/2016	12/27/2016	117	0.02	
12	Crane	Centurion – Delivery to Crane	N0195	12/29/2015	5/1/2016	124	0.02	
12	Crane	Centurion – Delivery to Crane	S7899	5/1/2016	9/1/2016	123	0.00	
12	Crane	Centurion – Delivery to Crane	S7929	9/1/2016	12/27/2016	117	0.02	
16	Crane	Plains WTI – Delivery to Crane	N0186	12/29/2015	5/1/2016	124	0.03	
16	Crane	Plains WTI – Delivery to Crane	S7892	5/1/2016	9/1/2016	123	0.00	
16	Crane	Plains WTI – Delivery to Crane	S7918	9/1/2016	12/27/2016	117	0.00	
24	Crane	Tank Manifold at Crane	G2959	12/29/2015	5/1/2016	124	0.00	
24	Crane	Tank Manifold at Crane	G3994	5/1/2016	9/1/2016	123	0.00	
24	Crane	Tank Manifold at Crane	G4048	9/1/2016	12/27/2016	117	0.02	
18	Cartman	Cartman Station ML (6645)	G2961	12/8/2015	4/19/2016	133	0.02	
18	Cartman	Cartman Station ML (6645)	G3996	4/19/2016	9/1/2016	135	0.00	
18	Cartman	Cartman Station ML (6645)	G4096	9/1/2016	12/12/2016	102	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	G2962	1/4/2016	4/1/2016	88	0.07	
18	Cedar Valley	Cedar Valley Station ML (6645)	G3997	4/1/2016	9/9/2016	161	0.00	
18	Cedar Valley	Cedar Valley Station ML (6645)	G4097	9/9/2016	1/3/2017	116	0.00	
18	Satsuma	Satsuma Station ML (6645)	G2963	12/30/2015	5/4/2016	126	0.04	
18	Satsuma	Satsuma Station ML (6645)	G3998	5/4/2016	9/2/2016	121	0.00	
18	Satsuma	Satsuma Station ML (6645)	G4098	9/2/2016	1/11/2017	131	0.00	
20	East Houston	East Houston ML (6645)	N0187	12/30/2015	4/14/2016	106	-0.02	
20	East Houston	East Houston ML (6645)	S7891	4/14/2016	8/31/2016	139	0.00	
20	East Houston	East Houston ML (6645)	S7920	8/31/2016	12/28/2016	119	0.00	
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	G2960	2/16/2016	4/29/2016	73	0.02	
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	G3995	4/29/2016	9/1/2016	125	0.00	
20	Speed Jct	Speed Jct Manifold from East Houston (6643)	G4094	9/1/2016	12/30/2016	120	0.00	
Refined Line								
8	Crane	8” Odessa to Crane (6648)	N0185	12/29/2015	5/1/2016	124	0.00	
8	Crane	8” Odessa to Crane (6648)	S7902	5/1/2016	9/1/2016	123	0.00	
8	Crane	8” Odessa to Crane (6648)	S7915	9/1/2016	12/27/2016	117	-	Lost in line
18	El Paso	18” Mainline (6645)	N0153	12/31/2015	4/27/2016	118	0.00	
18	El Paso	18” Mainline (6645)	N0155	4/27/2016	9/1/2016	127	0.00	
18	El Paso	18” Mainline (6645)	AX0105	9/1/2016	1/3/2017	124	0.00	
8	El Paso	8” Plains Outbound (6650)	N0154	12/31/2015	4/27/2016	118	0.00	
8	El Paso	8” Plains Outbound (6650)	AX0103	4/27/2016	9/1/2016	127	0.00	
8	El Paso	8” Plains Outbound (6650)	AX0104	9/1/2016	1/3/2017	124	0.00	

Line Pipe Anomalies/Repairs (Item 43)

A number of potential integrity threats were addressed in 2016. These included investigations (anomaly, POE, and 3rd party), new line crossings, ROW repair, pipeline marker repair, road crossings, line removal, and addressing exposed pipe. Table B-5 lists the 202 maintenance received. Note: 57 of the maintenance reports had corresponding positive material identification reports.

Table B-5. Maintenance Report Items

Maintenance Report Items	Number
3rd Party Investigation	3
4” Pipeline Removal	2
A-sleeve Cut Out	0
Address Exposed Pipe	3
Anomaly Investigation	154
Corrosion Cut Out	0
Dent Cut Out	0
Depth-of-Cover Survey	2
Depth-of-Cover for New Temporary Road Crossing	4
Fix Pipeline Marker	1
Lease Road Built Crossing ROW	2
Material Grade Testing Cut Out	0
New Fiber Optic Cable Crossing	7
New Irrigation Water Line Crossing	1
New 8” Pipeline Crossing	1
New 12” Pipeline Crossing	2
New 16” Pipeline Crossing	1
New 24” Pipeline Crossing	1
New 30” Pipeline Crossing	1
New 8” Poly Line Crossing	1
New 10” Poly Line Crossing	2
New Power Line Crossing	3
New Test Station	1
POE Investigation	0
Positive Material Identification	75
Third-Party Line Crossing	7
ROW Repair	1
Unauthorized Encroachment	2
Valve Stem Replacement	0

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 2016.

Periodic Fault Benchmark Elevation Data (Item 31)

Semi-annual fault displacement monitoring was performed on June 16, 2016 and December 2, 2016 which covers semi-annual fault measurements at the seven fault monitoring sites from inception in mid-2004[22] through December 2016.

Pipeline Maintenance Reports for Stream Crossings

Beginning in 2016, scour inspections were replaced by annual waterway inspections.

Flood Monitoring

Flood monitoring spreadsheets were received for the Colorado River, Pin Oak Creek, and Pedernales River. There were two instances where the flood stage was exceeded at the Pin Oak Creek in May 2016 and once at the Pedernales River in June 2016.

Waterway Inspection

The depth-of-cover above the pipe at the bottom of the Pin Oak Creek was inspected in July 2016 and the Colorado River in December in 2016. No exposures of the pipeline at the two stream beds were found.

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

Blasting Operation

A blasting operation was conducted near the Longhorn Pipeline in Johnson City, TX by a third party in November 2016. Kiefner received stress analysis calculations and site seismic monitoring records of ground vibration to review for potential impacts to the pipeline as a result of the blasting operations.

B.7. Maintenance and Inspection Reports

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

No new pipe exposures were identified in 2016. Four sites that have been actively managed under the Outside Forces Damage Prevention Program in accordance with the SIP were repaired after additional erosion was found. 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. Kiefner also received the bi-annual inspection reports for 2016.

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 2016.

Facility Inspection and Compliance Audits (Item 48)

Comprehensive safety inspections of each facility are conducted 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. Manned facilities are inspected once a year; unmanned facilities are inspected every two years. Pump stations located in sensitive and hypersensitive areas are inspected every two and one-half days. 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 2016.

Table B-6. Facility Safety Reviews

Facility	Manned	Tier	Inspection Date
Crane	Yes	II	6/15/16
Barnhart	No	II	7/8/16
El Paso East	Yes	I	5/26/16

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. 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 2016

Action Items	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
New	632	516	706	755	533	566	600	512	741	916	504	678	7659
Completed	630	516	687	750	533	562	597	512	729	904	504	676	7600
Open at End of Month	2	0	19	5	0	4	3	0	12	12	0	2	59

B.9. Significant Operational Changes

Number of Service Interruptions per Month (Item 70)

Table B-8. Service Interruptions per Month for 2016

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total*
No./Month	0	0	1	2	0	3	0	0	0	0	1	1	8

* From the Daily Ops Report ending Dec 31, 2016.

B.10. Incorrect Operations and Near-Miss Reports

During 2016 there were eight incidents within the Longhorn Pipeline System. Three involved releases, but were not DOT-reportable.

Five of the incidents involved human error (incorrect operations).

There were four hazard near-miss events. A hazard 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.

The first hazard near-miss involved a quick connect failure at a pig receiver trap at Cartman which was quickly isolated with no release of crude. The item was replaced and a valve was also installed upstream of the fitting.

The second occurred at Crane while installing an actuator on a drain block and bleed (DBB) valve. A small amount of product leaked through the valve body to the other side of the valve. After further discussion with the valve manufacturer, it was determined that the pressure must be equalized on both sides in order for the valve to stay seated while the actuator is being rotated. No product was released to the ground and no intermixing of non-compatible grades occurred. This near-miss event was due to human error involving improper installation.

The third hazard near-miss involved the installation of an electrical panel rack near the East Houston Terminal. The contractor was in the process of drilling to install piers for the foundation of the rack. The construction area was between the Longhorn inbound and outbound lines at East Houston. A facility locate form had been completed with all of the appropriate parties onsite and a one-call was completed. The facility locate form indicated that there were assets in the vicinity of the work. However, due to ongoing grading work in the area, the contractor neglected to stake out or mark the location of the planned piers. As a result, on the day of the excavation, the Magellan locator was not contacted to witness the excavation. Another inspector from a different project noticed where they were auguring and instructed them to stop work as they were near the Longhorn Pipeline. At that time they were at a depth of approximately ten feet and one foot to the side of the Longhorn Pipeline which was at a depth of twelve feet. This near-miss event was due to human error; procedures were not followed (Pipeline Locating and Excavation Safety).

The fourth hazard near-miss occurred at the Crane Station. While excavating to relocate a tank berm, the track hoe operator located a live lighting electrical conduit that had not been shown on the drawings during the facility locate.

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, 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 2016. 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 2016 there were no third-party incidents and no ROW near-misses.

Unauthorized ROW Encroachments (Item 52)

There were 57 ROW encroachments recorded in 2016, 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 2016 TPD Annual Assessment. There were no one-call violations in 2016.

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

The 2016 TPD Annual Assessment shows a 38% decrease in non-company activities from unique aerial patrol observations.

Aerial patrol data indicated that agricultural activity was observed 5 times (1.7% of non-company observations) in 2016, 17 times (3.6% of non-company observations) in 2015, and 7 times (2.1% of non-company observations) in 2014. 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) needs to be inspected once per week (not to exceed 12 days, but at least 52 times per year). Daily patrols are also required over the Edwards Aquifer Recharge Zone (MP170.5-MP173.3) with one patrol per week to be a ground-level patrol.

To meet this requirement through aerial patrols, the pipeline ROW was flown over daily from the Pecos River to 9th Street Junction (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 (every 2.5 days, not to exceed 72 hours)													
301: MP528 to E. Houston	13,472	13,853	13,660	13,994	14,079	13,668	15,320	12,544	13,921	14,095	11,263	10,641	**160,510**
Aerial Patrol (once / week, not to exceed 12 days)													
303: MP528 to MP694	1,056	1,056	1,320	792	1,056	1,320	1,056	792	1,056	1,056	1,320	1,056	**13,200**
Ground Patrol (once / week)													
Edwards Aquifer: MP170.5-MP173.3	22.4	30.8	16.8	19.6	16.8	11.2	11.2	33.6	16.8	25.2	42	39.2	**286**

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 a few exceptions due to bad weather in March, August, November, and December.

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from the Pecos River (MP528) to the El Paso Terminal (MP694), including the El Paso Laterals.

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	1	1	2	13	7	3	47	119	12	106	4	0	315

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 2016.

Table B-11. Educational and Outreach Meetings

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25	30	30
School Program:												
School Program - Houston	2	2	3	4		6	5	6	1	3	4	4
School Program - Austin	3	2	7	3	4	3	4	5	5	2	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	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 2016 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	311	313	380	399	392	412	421	528	393	426	413	357	4745
II	717	664	778	765	742	744	854	1045	885	1002	808	702	9706
III	241	222	253	256	254	256	280	308	272	309	250	210	3111
Total	1270	1199	1411	1420	1388	1412	1554	1880	1551	1737	1471	1269	17562

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 2016 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	289	256	296	260	237	242	111	0	1	0	1	0	1693
Pipeline Safety	161	121	130	100	108	105	50	0	1	0	1	0	777
Call Before You Dig	130	52	51	62	67	78	31	4	0	8	2	0	485
Call Before You Dig Video	0	1	0	0	1	7	0	0	0	0	0	0	9
System Integrity Plan	135	114	94	92	75	105	34	2	4	3	2	0	660
Longhorn Info.	271	261	326	273	357	296	122	4	10	19	3	0	1942
Pipeline Emergencies	46	35	32	35	18	35	17	0	0	0	0	0	218
Home Page – 811	0	0	0	0	1	0	0	0	0	0	0	0	1

Number of ROW Encroachments by Month (Item 67)

The number of ROW encroachments during 2016 is shown in the following table. The Annual TPD Report identified 57 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	4	5	6	3	9	6	0	7	2	6	3	4	55
Unauthorized	0	0	2	0	0	0	0	0	0	0	0	0	2
Total	4	5	8	3	9	6	0	7	2	6	3	4	57

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

No physical hits were reported from 2012 through 2016. 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 2016 Annual Third-Party Damage Prevention Program Assessment (TPD Annual Assessment) was received in August 2017. 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 17,562 one-call notifications were made.

Table B-15. One-Call Activity by Month

Month	One-Call Clear	Field Locate	Total Tickets
Jan	616	230	1270
Feb	574	264	1199
Mar	660	319	1411
Apr	725	253	1420
May	696	242	1388
Jun	736	271	1412
Jul	813	279	1554
Aug	1083	325	1880
Sep	894	252	1551
Oct	952	265	1737
Nov	770	252	1471
Dec	610	243	1269
Totals	9129	3195	17562

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

Kiefner received incident data and investigation reports for eight incidents along the Longhorn Pipeline System for 2016. Table B-16 provides a brief summary of these incidents. Four of the incidents were minor and four were hazard near-misses (HNM). Three involved releases, but were not DOT-reportable. The incident investigations identified human error as the primary cause for six of the incidents, which generally involved a failure to follow procedures and/or inaccurate drawings.

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.

Minor Incident

- 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 workdays cases
- Citations under $25,000

Significant Incident

- 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

Major Incident

- 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

There were no metallurgical failure analyses conducted during 2016.

Table B-16. Summary of Incidents for 2016

Incident	Brief Description	Cause	Magellan Class	DOT Reportable
1/4/2016 Crane, Tank Coating Contractor	Coating contractor prepping internal tank floor for coating with steel shot blasting machine. Operator stopped operations and put machine in neutral to help carry bucket of steel shot to refill machine. When returned, noticed machine sparking. Rubber wheel caught fire. Wheel had locked up and caused gouge/hole in tank floor.	• Human error. Operator should never leave equipment when power is on. • Equipment failure	Minor	No
1/14/2016 El Paso, Filter Drain Release	Contractor working on filter operation at truck rack manifold took cap off 2-inch drain, left work area, did not tell co-workers or Magellan employees that he removed cap. Operations subsequently needed to drain water boot off filter vessel into the 2-inch drain. Diesel/water mixture released from drain line where cap had been removed.	• Human error	Minor	No
5/16/2016 Cartman, Quick Connect Failure (HNM)	After filling pig receiver trap with crude and preparing to remove pressure from trap, air was escaping from test port fitting on relief valve.	• Equipment failure (quick connect fitting) • Human error. Valve not installed upstream of quick connect fitting.	HNM	No
9/28/2016 Crane, Product Quality (HNM)	While installing an actuator on a double block and bleed (DBB) valve, downstream side of valve empty, upstream full, while rotating actuators seat became unseated, allowing small amount of product to flow.	• Human error. Improper installation. Pressure must be equalized prior to rotating actuator.	HNM	No
10/6/2016 El Paso, Overfill truck compartment, release	Driver overfilled one of his diesel fuel compartments by 91 gallons. All but 2 gallons remained inside the secondary containment and sump. The trailer being loaded was not the normal trailer for the driver and it had different compartment volumes, he had just swapped trailers prior to loading at Magellan. Driver entered the wrong quantity.	• Human error. Driver entered incorrect amount. Driver instructions not followed.	Minor	No
10/28/2016 E Houston Link (HNM)	Contractor drilling 10-ft to construct piers in vicinity of Longhorn Pipeline. Facility locate form and one-call had been completed. Facility locate form indicated assets in vicinity of the work. However, due to ongoing grading work in area the contractor neglected to mark the location of the planned piers. As a result on the day of the excavation, the Magellan locator was not contacted to witness the excavation. Another inspector from a different project noticed where they were auguring, and instructed them to stop as they were near the Longhorn Pipeline inside the fence. At that time they were at a depth of approximately 10' and 12" to side of the LH line. The LH pipeline was at a depth of 12'. The pipeline was not hit.	• Human error. Procedures not followed (Pipeline Locating, Excavation Safety).	HNM	No
12/2/2016 Crane, Conduit	While excavating to relocate a tank berm, trackhoe operator almost contacted a live	• Human error. Conduit not shown on drawings.	HNM	No

Incident	Brief Description	Cause	Magellan Class	DOT Reportable
(HNM)	electrical lighting conduit. Conduit scratched.			
12/29/2016 El Paso, Equipment Failure	Operator noticed a leak on a secondary pump for tank. Transmix (2 gallons) leaked past a locked out/tagged out valve into drip pan and overflowed to earthen containment.	• Equipment failure • Pump and valves had been locked out for 1½ years waiting on pipe modifications. Product leaked through valve, then thermal relief caused a pump gasket rupture.	Minor	No

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 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 at or below 1 x 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 2016 and executed. Results show no areas along the pipeline with PoF greater than 1 x 10^{-4} failures and as such supports the effectiveness of Magellan's existing Integrity Management Program (IMP). No additional mitigative measures are required or recommended at this time.

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

The 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 PHA is required, and Magellan's procedures provide that the asset integrity engineer should determine the appropriate PHA methodology for change requests.

Two PHAs were performed in 2016. One was for the El Paso Terminal Holly Receipt and Storage Tank Project. The analysis focused on the addition of two incoming pipelines from

Holly and included metering, proving, rack manifolds, and a new storage tank. A PHA was also conducted for the Crane Terminal Expansion. The scope of the study was the addition of a storage tank to accommodate current and future Longhorn crude product grades, including WTS, WTI, or crude condensate.

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

PHMSA Advisories

DEPARTMENT OF TRANSPORTATION ADB-2016-06, December 9, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2016-0137; FR Cite: 81 FR 89183
Pipeline Safety: Safeguarding and Securing Pipelines from Unauthorized Access
Summary:

- PHMSA is issuing this Advisory Bulletin in coordination with the Department of Homeland Security's (DHS), Transportation Security Administration (TSA), to remind all pipeline owners and operators of the importance of safeguarding and securing their pipeline facilities and monitoring their Supervisory Control and Data Acquisition (SCADA) systems for abnormal operations and/or indications of unauthorized access or interference with safe pipeline operations. Additionally, this Advisory Bulletin is to remind the public of the dangers associated with tampering with pipeline system facilities.
- This Advisory Bulletin follows recent incidents in the United States that highlight threats to oil and gas infrastructure. On October 11, 2016, several unauthorized persons accessed and interfered with pipeline operations in four states, creating the potential for serious infrastructure damage and significant economic and environmental harm, as well as endangering public safety. While the incidents did not result in any damage or injuries, the potential impacts emphasize the need for increased awareness and vigilance.

https://www.federalregister.gov/documents/2016/12/09/2016-29500/pipeline-safety-safeguarding-and-securing-pipelines-from-unauthorized-access

DEPARTMENT OF TRANSPORTATION ADB-2016-05, August 16, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: PHMSA-2016-0075; FR Cite: 81 FR 54512
Pipeline Safety: Clarification of Terms Relating to Pipeline Operational Status
Summary:

- PHMSA is issuing this advisory bulletin to all owners and operators (operators) of hazardous liquid, carbon dioxide, and gas pipelines, as defined in 49 Code of Federal Regulations Parts 192 and 195, to clarify the regulatory requirements that may vary depending on the operational status of a pipeline.
- Further, this advisory bulletin identifies regulatory requirements operators must follow for the abandonment of pipelines. Pipeline owners and operators should verify their

operations and procedures align with the regulatory intent of defined terms as described under this bulletin.

- Congress recognized the need for this clarification in its Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016.

https://www.federalregister.gov/documents/2016/08/16/2016-19494/pipeline-safety-clarification-of-terms-relating-to-pipeline-operational-status

DEPARTMENT OF TRANSPORTATION ADB-2016-04, June 21, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: Docket No. PHMSA-2016-0071; FR Cite: 81 FR 40398
Pipeline Safety: Ineffective Protection, Detection, and Mitigation of Corrosion Resulting From Insulated Coatings on Buried Pipelines
Summary:

- PHMSA is issuing this advisory bulletin to remind all owners and operators of hazardous liquid, carbon dioxide, and gas pipelines, as defined in 49 Code of Federal Regulations (CFR) Parts 192 and 195, to consider the overall integrity of the facilities to ensure the safety of the public and operating personnel and to protect the environment.
- Operators are reminded to review their pipeline operations to ensure that pipeline segments that are both buried and insulated have effective coating and corrosion-control systems to protect against cathodic protection shielding, conduct in-line inspections for all threats, and ensure in-line inspection tool findings are accurate, verified, and conducted for all pipeline threats.

https://www.federalregister.gov/documents/2016/06/21/2016-14651/pipeline-safety-ineffective-protection-detection-and-mitigation-of-corrosion-resulting-from

DEPARTMENT OF TRANSPORTATION ADB-2016-03, February 11, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: Docket No. PHMSA-2016-0013; FR Cite: 81 FR 7412
Pipeline Safety: Dangers of Abnormal Snow and Ice Build-up on Gas Distribution Systems
Summary:

- This advisory bulletin advises owners and operators of petroleum gas and natural gas facilities of the need to take the appropriate steps to prevent damage to pipeline facilities from accumulated snow or ice.
- Past events on natural gas distribution system facilities appear to have been related to either the stress of snow and ice or the malfunction of pressure control equipment due to ice blockage of pressure control equipment vents.
- This advisory reminds owners and operators of the need to take precautionary actions to prevent adverse events.

https://www.federalregister.gov/documents/2016/02/11/2016-02704/pipeline-safety-dangers-of-abnormal-snow-and-ice-build-up-on-gas-distribution-systems

DEPARTMENT OF TRANSPORTATION ADB-2016-02, February 5, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.

DEPARTMENT OF TRANSPORTATION ADB-2016-01, January 19, 2016
AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA); DOT.
Docket Number: Docket No. PHMSA-2015-0283; FR Cite: 51 FR 2943
Pipeline Safety: Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scout, and River Channel Migration
Summary:

- PHMSA is issuing this advisory bulletin to remind all owners and operators of gas and hazardous liquid pipelines of the potential for damage to pipeline facilities caused by severe flooding and actions that operators should consider taking to ensure the integrity of pipelines in the event of flooding, river scour, and river channel migration.

https://www.federalregister.gov/documents/2016/01/19/2016-00765/pipeline-safety-potential-for-damage-to-pipeline-facilities-caused-by-flooding-river-scour-and-river

B.15. DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2016.

B.16. Literature Reviewed

See references.