Magellan Pipeline Company

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2019 Operational Reliability Assessment of the Longhorn Pipeline System

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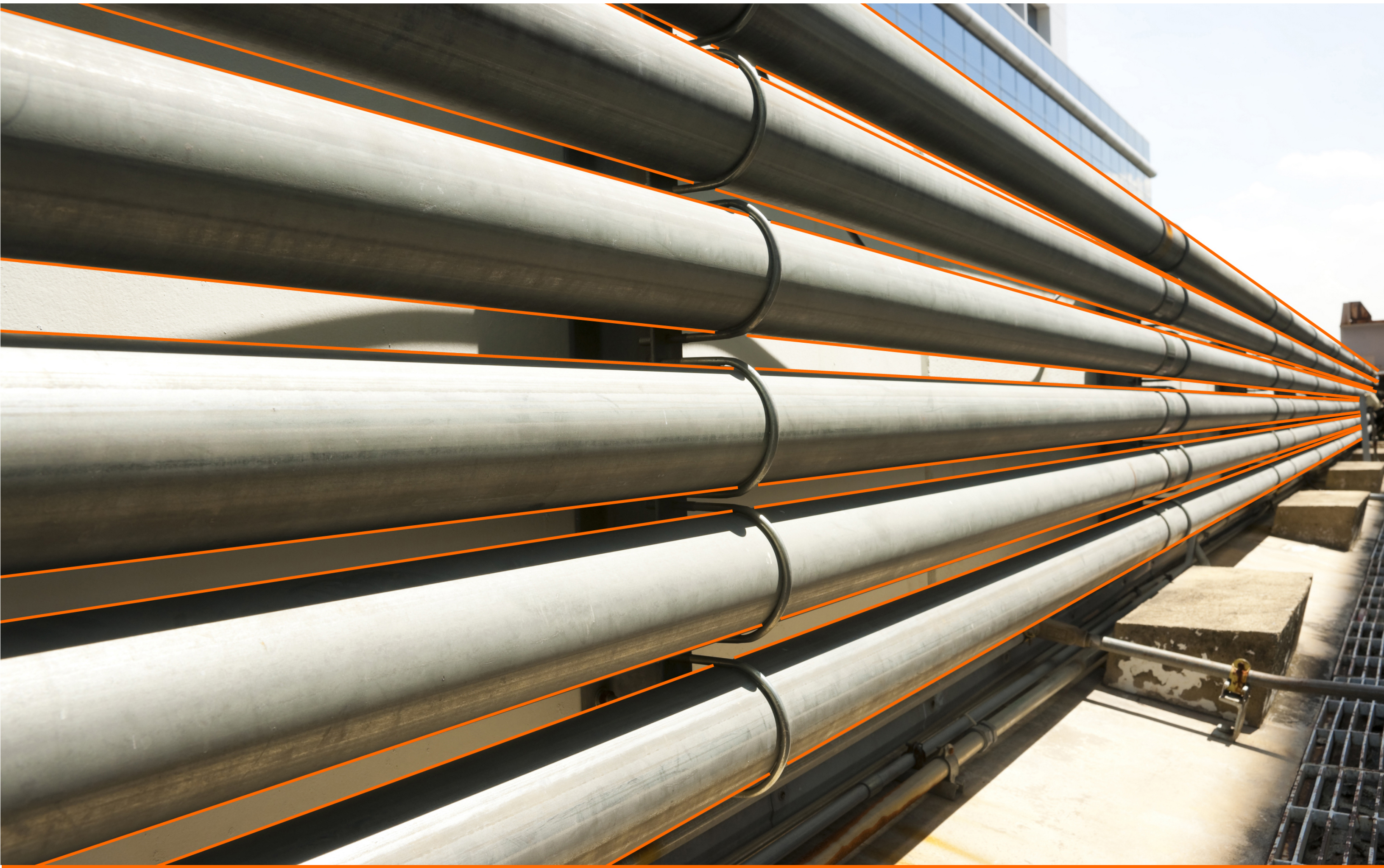

ENERGY & INDUSTRY DIVISION

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to

Magellan Pipeline Company

on

March 31, 2021

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EXECUTIVE SUMMARY

This report presents the annual Operational Reliability Assessment (ORA) of the Longhorn Pipeline System for the 2019 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, indicates the Texon to Barnhart segment of the line will require the next reassessment for pressure cycle fatigue susceptibility based on the threshold of detection based on the transverse field inspection (TFI) tool run completed in 2015. The reassessment for this segment is due in late 2022, however, Magellan conducted an ultrasonic crack detection (UCD) tool inspection on this segment in 2020 and will likely be the basis for the reassessment of this segment in the future. The pressure cycle fatigue analysis of recent UCD ILI indications reported for the Crane to Texon segment resulted in a minimum reassessment interval of 11.4 years (reassessment due early 2030). All indications reported on the Satsuma to East Houston segment resulted in calculated reassessment intervals greater than 64 years.

The 2019 maintenance and non-destructive evaluation (NDE) reports were reviewed and correlated to in-line inspection (ILI) assessments from 2018 and 2019 to validate the ILI specified tool performance using the supplied background information and the API 1163 ILI validation methodology. Thirty-one of the maintenance reports included ILI anomaly investigations. The ILI anomaly investigations found correlating features on all the referenced digs. Seven crack-like reported features were evaluated in-ditch on the Satsuma to East Houston segment and were all found to be cracked. Thirty crack-like reported features were also evaluated on the Crane to Texon segment; eight were found to be cracks (26.7%), six were found to be lack of fusion (20%), and 16 were found to be mill defects (53.3%). A run-to-run comparison was performed to determine external and internal corrosion growth rates (CGRs) for the ILI assessments performed or received in 2019. Calculated external upper bound CGRs ranged from 5.4 to 13.1 mpy while internal CGRs ranged from 2.5 to 8.4 mpy. The run-to-run comparisons indicated external/internal metal loss (ML) feature mismatch on the Satsuma to East Houston and East Houston to Speed Jct segments between the 2019 and 2014 ILI assessments. Magellan continues to conduct field investigations to remediate and validate metal loss as necessary.

The corrosion management data have been reviewed including internal corrosion coupon data, rectifier inspections, test point surveys, close interval surveys (CIS), atmospheric inspections, and tank inspection reports. Internal corrosion coupons continue to show low corrosion rates (≤0.62 mpy). The CIS was performed in 2019 and received by Magellan in 2020 for the pipeline right-of-way (ROW) from stationing 395+56 to 26340+35. The CIS data will be analyzed and summarized in the 2020 Longhorn ORA Report. Semi-annual surveys are being conducted on Tier II and Tier III areas per Longhorn Mitigation Commitment (LMC) 32. Atmospheric inspection and tank inspection reports indicate no immediate action is required. Monitoring should continue to identify future potential changes.

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 2019. The 227 ID reductions identified from the 2019 electronic geometry pig (EGP) assessments were compared to the existing laminations reported by the 2009/2010 UT assessments. One dent and 23 geometric anomalies (GMA) were found to either correlate or be present on the same joint as a lamination reported from the 2009/2010 UT assessments; the one dent and three GMAs that correlated have been previously repaired. Based on the 2019 maintenance reports, four laminations were found. Monitoring reported laminations for ID reductions might indicate the initiation of a hydrogen blister; however, no blisters were found during the 2019 dig program. Magellan should continue to monitor for lamination anomalies with ILI tools.

Earth movement and water forces can result in primary integrity concerns of 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 the long-term historical rates of movement at all the faults, except Hockley, continue to be slow and the pipeline crossing those faults have more than 100 years[1] to reach the allowable displacement. However, the short-term rate of movements at Akron, Hockley, McCarty, and Negyev faults reveal that they have been more active lately. Kiefner is recommending a more frequent monitoring than the default semi-annual frequency for the Akron fault. If the same rate of movement (i.e., 0.077 inches per year) continues in 2020, a more detailed analysis, such as finite element method, should be conducted for a more robust predictive capability of if/when/where fault movements become critical. In 2019, Magellan performed maintenance activities to relieve strain on the pipeline at the Hockley fault. However, Kiefner recommends a close monitoring of this fault due to its continuously high rate of movement. McCarty and Negyev faults also require close monitoring due to the relatively short time to failure for pipes crossing these faults.

The last recorded waterway inspections at the five river crossings (Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River) are from September 2017. The Cypress Creek crossing has the only exposure. Magellan recorded this exposure in a 2003 maintenance report, conducted mitigation in 2005 by recoating it, and monitors it periodically. A depth-of-cover (DOC) survey was only conducted for the Pin Oak Creek crossing in 2019. The maximum cover depth at Pin Oak Creek was found to be 4 feet. Close monitoring for the latter is recommended as there appear to be fluctuations in the DOC. The pipeline has been buried deep below the crossing at both Brazos River and Colorado River via horizontal directional drilling (HDD). The 2017 inspection report, by ONYX, indicated there were no exposed pipelines at the crossings, with all locations maintaining adequate DOC. The James River and Llano River waterways were inspected in 2018. Inspections indicate a DOC of 1.5ft at the Llano River crossing and exposed pipeline at the James River crossing. No remediation or mitigation has been reported for the latter. DOC survey and flood monitoring should be conducted periodically to ensure that the integrity of the pipeline is not jeopardized.

[1] This is the total time calculated from when the pipe is free of stress, i.e. since installation or the last time some form of stress relief was performed on it

The Longhorn third-party damage (TPD) prevention program exceeds the minimum requirements of federal and Texas state pipeline safety regulations. The aerial surveillance and ground patrol frequencies met the goals set forth in the Longhorn Mitigation Plan (LMP) with a few exceptions due to weather events in February, March, and May of 2019. However, following event cessation, Magellan was able to begin and complete patrols within 72 hours.

Magellan performs incident investigations on all events including near misses. During 2019, there were three incident investigations on the Longhorn Pipeline. Two incidents were classified as equipment failures: one minor and one significant. The minor incident was a power surge at the Crane Terminal and the significant incident involved a fire at the El Paso Terminal just after a lightning strike in the area. Both incidents were not reportable to PHMSA. The third incident was a one-call violation.

No occurrence of stress-corrosion cracking (SCC) has been recorded on the pipeline, including the 449 miles of the Existing Pipeline. Magellan should continue 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.

The 2019 facilities data indicate the pump stations and terminal facilities have been properly maintained and operated and have had no adverse impact on public safety. Process Hazard Analyses (PHAs) are performed on all new above ground facilities, when changes occur in existing facilities, and at 5-year intervals to evaluate and control potential hazards associated with the operation and maintenance of the facilities. Eight PHAs were completed and reviewed by Kiefner as a part of the ORA. The PHA techniques chosen were the Hazard and Operability Study and What-if Analysis. The HAZOP and What-if analysis process and requirements are well defined in 29 CFR 1910.119(e)(2)(i) Et. Seq. Kiefner did not participate in the PHA process; therefore, our review consisted of a document review of the final deliverables. The PHA's that were reviewed indicated that all were well attended by an expected level of operational and PHA leaders with appropriate training, skill, and knowledge of the system. It appears that the nodes identified were appropriate for the process and systems; and the discussion of the standard process upsets was thoroughly reviewed and considered. For the review of upset process hazard conditions, an appropriate risk matrix was developed, and risks were well prioritized into categories consistent with a system of this type. Additionally, for each hazard a review of the appropriate controls applicable to their hazards and their interrelationships appears to have been reviewed and addressed as well as the consequences thereof.

A probabilistic risk model has been used to effectively manage pipeline integrity and evaluate risk in accordance with 49 CFR 195.452. The results show that none of the pipeline segments exceeded Magellan's risk threshold; therefore, no additional mitigation 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 minimum required mileage for both aerial surveillance and ground patrol in the total number of miles patrolled and met the frequency requirement for patrol when weather permitted. In addition, public-awareness meetings were held, a new/enhanced damage prevention program was implemented, and ROW markers and signs were repaired or replaced where necessary.

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Terms, Definitions and Acronyms

Many of the terms and definitions are taken directly from Section 2.0 of the ORA Process Manual (ORAPM) titled Terms, Definitions, and Acronyms. Definitions in the ORAPM or Longhorn Mitigation Plan are italicized.

Accident	As stated in the LMP, an undesired event that results in harm to people or damage to property.
AC	Alternating Current
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
Bbl	barrels
BHGE	Baker Hughes, a GE Company
bpd	barrels per day
bph	barrels per hour
CFR	Code of Federal Regulations
CGR	Corrosion growth rate
CIS	Close interval survey
CMP	Corrosion Management Plan
CMS	Content Management System
CP	Cathodic Protection – A method of protection against galvanic corrosion of a buried or submerged pipeline through the application of protective electric currents.
Def	Deformation
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 • Environmental Impact Statement (EIS)
EFW	Electric-flash weld is a type of EW using electric-induction to generate weld heat.
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 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
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 the flow of the electric current. EW pipe has one longitudinal seam produced by the EW process.
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.
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
GMA	Geometric Anomaly – An ID Reduction less than 2% of pipe diameter

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)
Hydrostatic Test	An integrity verification test that pressurizes the pipeline with water also called a hydrotest or hydrostatic pressure test.
ID	Inside nominal diameter of line pipe
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
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 a part of the currently active Longhorn Pipeline, and the actual junction is at MP 9 (2 miles from the J-1 Valve).
Jct	Junction
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.

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

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

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

Magellan Magellan Pipeline Company, L.P.

Major Incident 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

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.

ML Metal loss

MOCR Management of Change Recommendation

MOP Maximum Operating Pressure

MP	Mile Post
mpy	Mils per year – Often referenced in conjunction with corrosion growth rates
NACE	NACE International – Formerly known as the National Association of Corrosion Engineers
NDE	Non-destructive Evaluation
Near-Miss	Number of unplanned/undesired third-party related events that did not result in significant loss but which, under slightly different circumstances, could have resulted in a minor, serious or major incident. Near miss data are obtained from Hazard / Near Miss cards, incident investigations, aerial patrol reports, maintenance reports and ROW inspection reports. An event defined in the Incident Investigation Program of the LMP as an undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property. In addition, the LMP states: a specific scenario of a minor accident (minor actual loss) could also be a major near-miss (major potential loss). Thus, a near-miss may or may not result in an incident.
NEPA	National Environmental Policy Act
New Pipeline	In 1998 extensions were added to the Existing Pipeline to make the current Longhorn Pipeline. Extensions were added from Galena Park to MP 9 and Crane to El Paso Terminal. Laterals were added from Crane to Odessa and from El Paso Terminal to Diamond Junction. In 2010 a 7-mile loop (3 ½ miles each way) was added, connecting Magellan's East Houston terminal to MP 6.
OD	Outside nominal diameter of line pipe.
One-Call	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. 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
PHA	Process Hazard Analysis
PHMSA	The Pipeline and Hazardous Materials Safety Administration, the federal agency within DOT with safety jurisdiction over interstate pipelines.
PMI	Positive Material Identification
Positive Material Identification (PMI) 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.
POE	Probability of Exceedance – The likelihood that an event will be greater than a pre-determined level; used in the ORA to evaluate corrosion defect failure pressures versus intended operating pressures. The POE for depth (POE_D) is the probability that an anomaly is deeper than 80% of wall thickness. The POE for pressure (POE_P) is the probability that the burst pressure of the remaining wall thickness will be less than the system operating pressure or surge pressure. The POE for each pipe joint is POE joint.
POF	Probability of Failure
Recommendation	Suggestion for activities or changes in procedures that are intended to enhance integrity management systems, but are not specifically mandated in the LMP

Repair	The LMP describes a repair as a temporary or permanent alteration made to the pipeline or its affiliated components that are intended to restore the allowable operating pressure capability or to correct a deficiency or possible breach in mechanical integrity of the asset.
Requirement	Activities that must be performed to comply with the LMP commitments
Risk	A measure of loss measured in terms of both the incident likelihood of occurrence and the magnitude of the consequences
Risk Assessment	A systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes and be performed at varying levels of detail depending on the operator's objectives.
ROW	Right-of-way – A strip of land where, through a legal agreement, some property rights have been granted to Magellan and its affiliates. The ROW agreement enables Magellan to operate, inspect, repair, maintain or replace the pipeline.
SCC	Stress-Corrosion Cracking – A form of environmental attack on 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[2])
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
SMYS	Specified Minimum Yield Strength – A common measure of the minimum
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.
TDW	T.D. Williamson
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

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

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.
UltraScan™ CD (UCD)	BHGE's ultrasonic crack detection in-line inspection tool.
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)

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1 INTRODUCTION

1.1 Objective

The annual Operational Reliability Assessment (ORA) report on the Longhorn Pipeline System for the 2019 operating year has been conducted by Kiefner and Associates, Inc. (Kiefner). The ORA report 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 Longhorn pipeline system has been operated by Magellan since 2005 and under Magellan's ownership since 2009. 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. The EA took place prior to the then newly configured pipeline refined product service. The EA "Finding of No Significant Impact" was conditioned upon Longhorn's commitment to implement certain integrity-related activities and plans prior to pipeline start-up and periodically throughout the operation of the system. Longhorn's commitment to minimize the likelihood and consequences of product releases was specified in the Longhorn Mitigation Plan (LMP). These commitments included the Longhorn Continuing Integrity Commitment wherein Longhorn agreed to implement System Integrity and Mitigation Commitments and conduct annual ORAs. A list of the Longhorn Mitigation Commitments (LMCs) addressed in the ORA report is provided in Appendix A – Mitigation Commitments.

The LMP committed Longhorn to retaining an independent third-party technical company to perform the annual 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 ORA contractor will assess the pipeline operating data and the results of integrity assessments, surveys, and inspections, and will make appropriate recommendations with respect to the seven potential threats to pipeline integrity. The ORAPM identifies the list of data needed to conduct the ORA; Appendix B – New Data used in this analysis provides the data used for the 2019 ORA Report. 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)[3]
7. Threats to Facilities Other than Line Pipe

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 which are listed below, that are used to formulate prevention and mitigation recommendations that are directly implemented periodically 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 the performance of ORA functions. Integrity intervention and inspection recommendations resulting from the ORA analyses are implemented by the LPSIP. A diagram of the functions and relative interactions of the LPSIP and the ORA is provided in Figure 1.

1. Corrosion Management Plan
2. In-Line Inspection (ILI) 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

[3]SCC has not been identified as a threat of concern to the Longhorn Pipeline and has not been recognized as a threat in the past, but was added as SCC has been an unexpected problem for some pipelines.

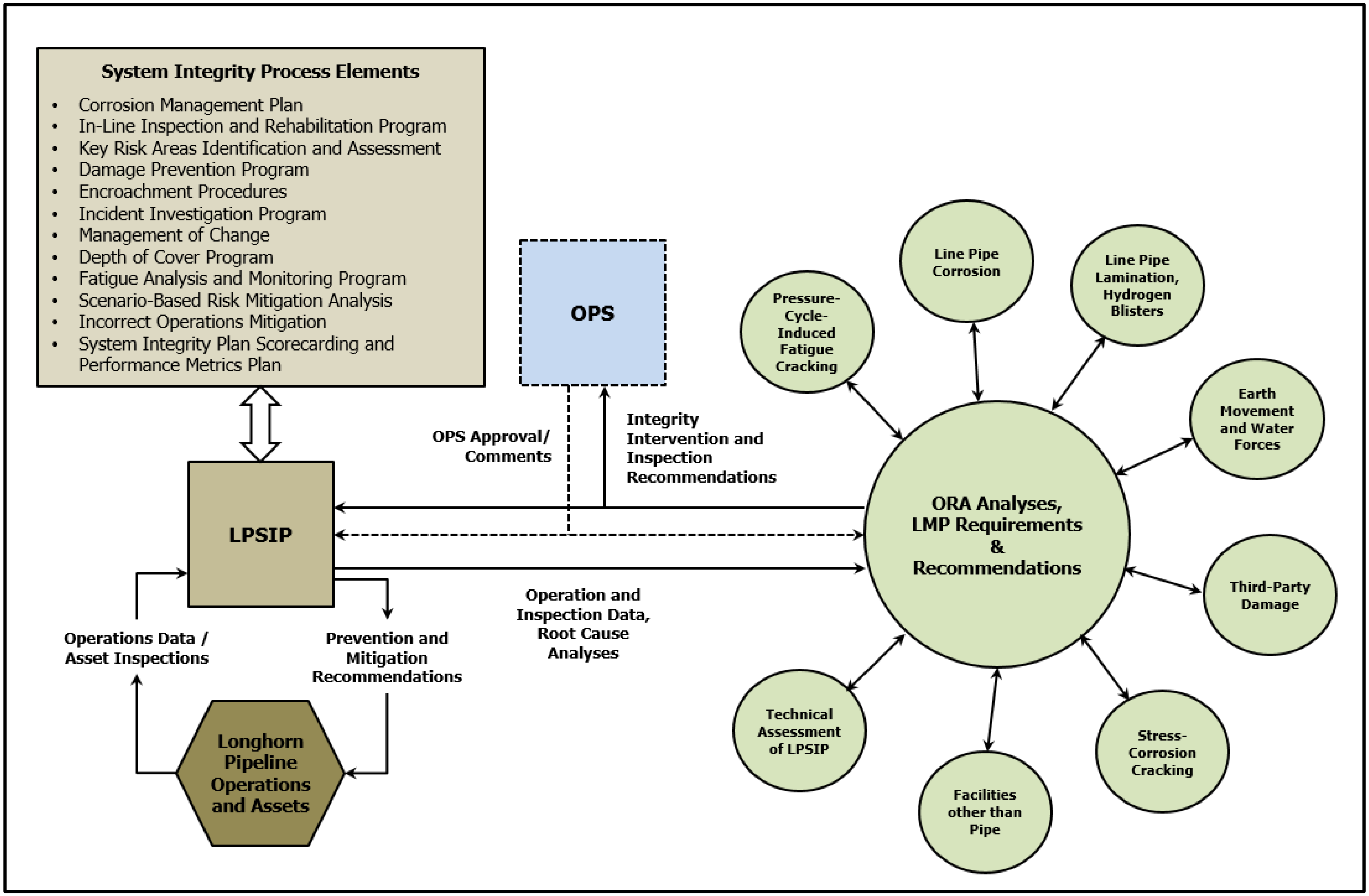

Figure 1. ORA Functions and Interaction with the LPSIP

1.4 Longhorn Pipeline System Description

The Longhorn pipeline system is comprised of a crude oil system (Eastern portion) and a refined products system (Western portion). Figure 2 shows the Longhorn System Map. Tier Levels are shown in Figure 3. A close-up of the Houston area is shown in Figure 4.

The Eastern portion of the Longhorn system transports crude oil through an 18-inch pipeline over 424 miles from Crane Station to Satsuma Station. Intermediate pumping stations are located at Texon, Barnhart, Cartman, Kimble County, James River, Eckert, Cedar Valley, Bastrop, Warda, and Buckhorn. The crude system continues with 32 miles of 20-inch pipe from Satsuma Station to East Houston Terminal and 9 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 Western portion of the Longhorn system transports refined products from Odessa to El Paso, TX. The refined product system is made up of 237-miles of 18-inch pipe from Crane Station to the El Paso Terminal and 29 miles of 8-inch pipe from Odessa to Crane Station. At the El Paso Terminal, there are 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. A timeline showing the history of the Longhorn Pipeline System is shown in Figure 5. The station locations for the Longhorn pipeline systems are listed in Table 1.

Table 1. Longhorn Pipeline Station Locations

System	Station	Type	Milepost	Tier	MOP (psig)
Crude	Crane	Pump	457.5	II	1034
	Texon	Pump	416.6	II	898
	Barnhart	Pump	373.4	II	898
	Cartman	Pump	344.3	II	952
	Kimble County	Pump	295.2	II	898
	James River	Pump	260.2	I	965
	Eckert	Pump	227.9	I	959
	Cedar Valley	Pump	181.6	II	965
	Bastrop	Pump	141.8	I	981
	Warda	Pump	112.9	I	965
	Buckhorn	Pump	68.0	I	787
	Satsuma	Pump	34.1	III	786
	E. Houston	Terminal	2.35	II	1168
Refined Product	Odessa[4]	Meter	NA	I	1440
	Crane	Pump	457.5	I	1440
	Cottonwood	Valve	576.3	I	1440
	El Paso	Terminal	694.4	I	1440

The current flow rate for the crude system is 292,000 barrels per day (bpd) from Crane to East Houston. The flow rate for the refined product system is 64,000 bpd from Odessa to El Paso. There were no operational changes to the Longhorn Pipeline System during 2019.

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

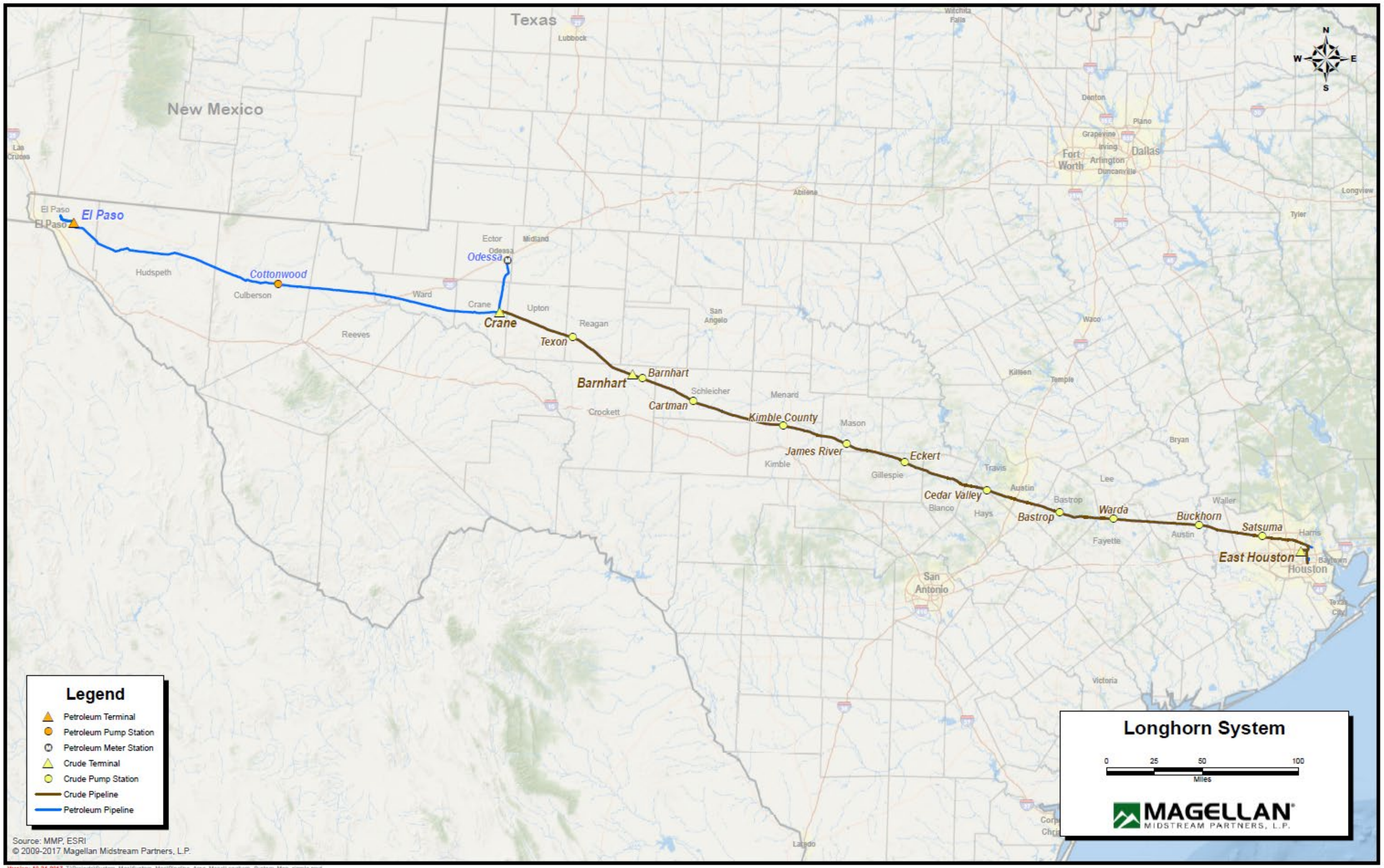

Figure 2. Longhorn System Map (2019)

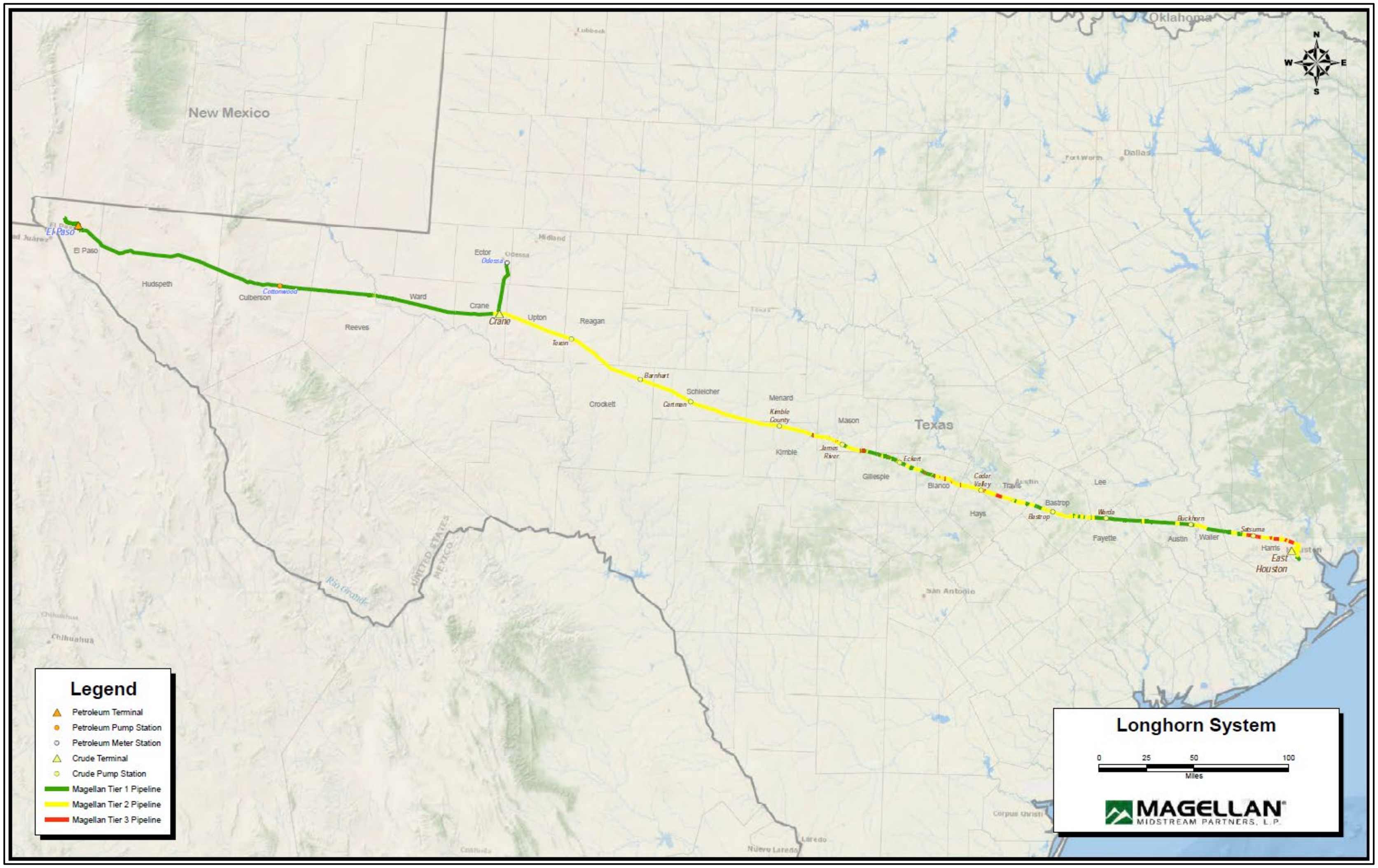

Figure 3. Longhorn System Map showing Tier Level (2019)

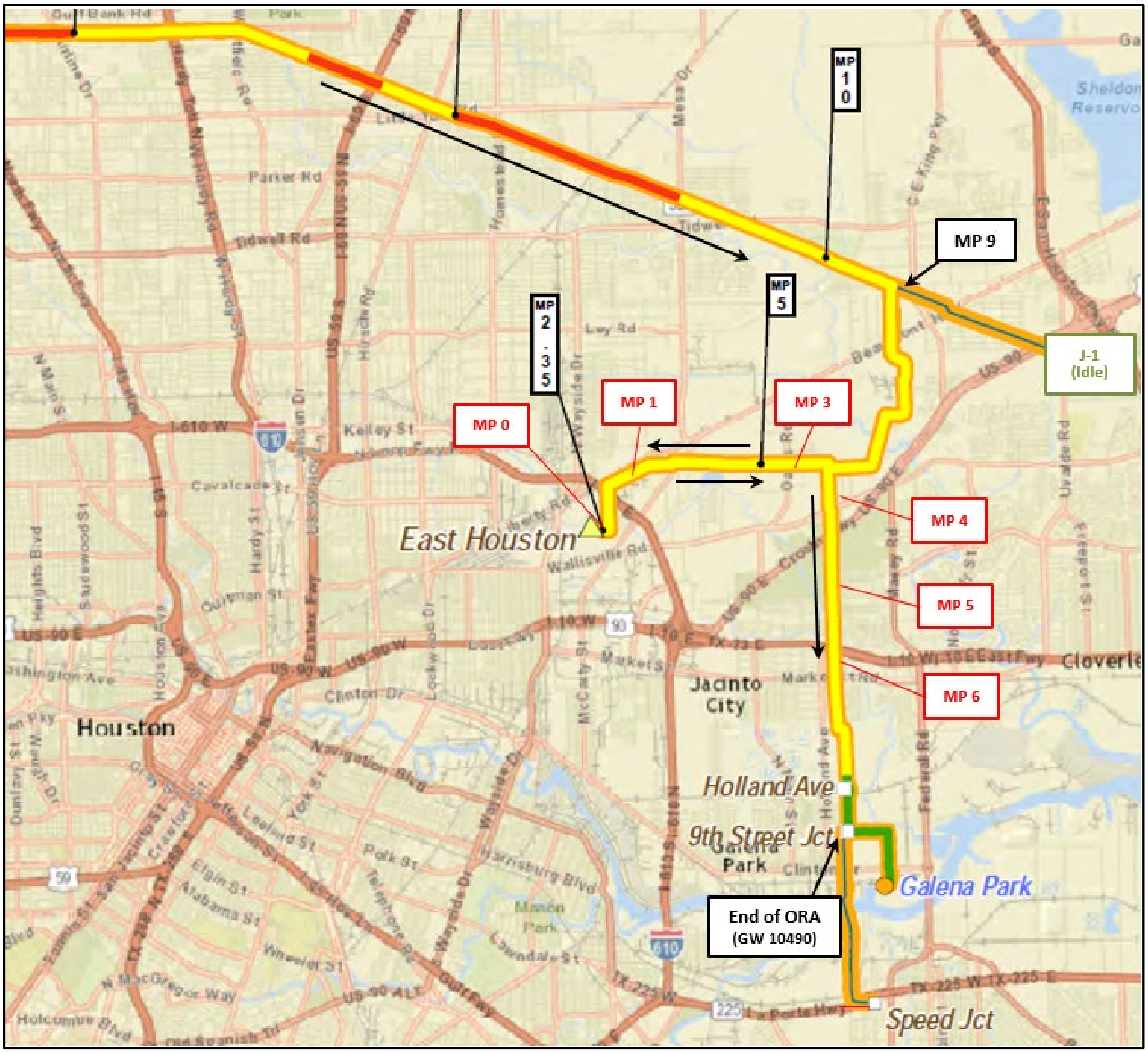

Figure 4. Map of Longhorn System within Houston Area (2019)

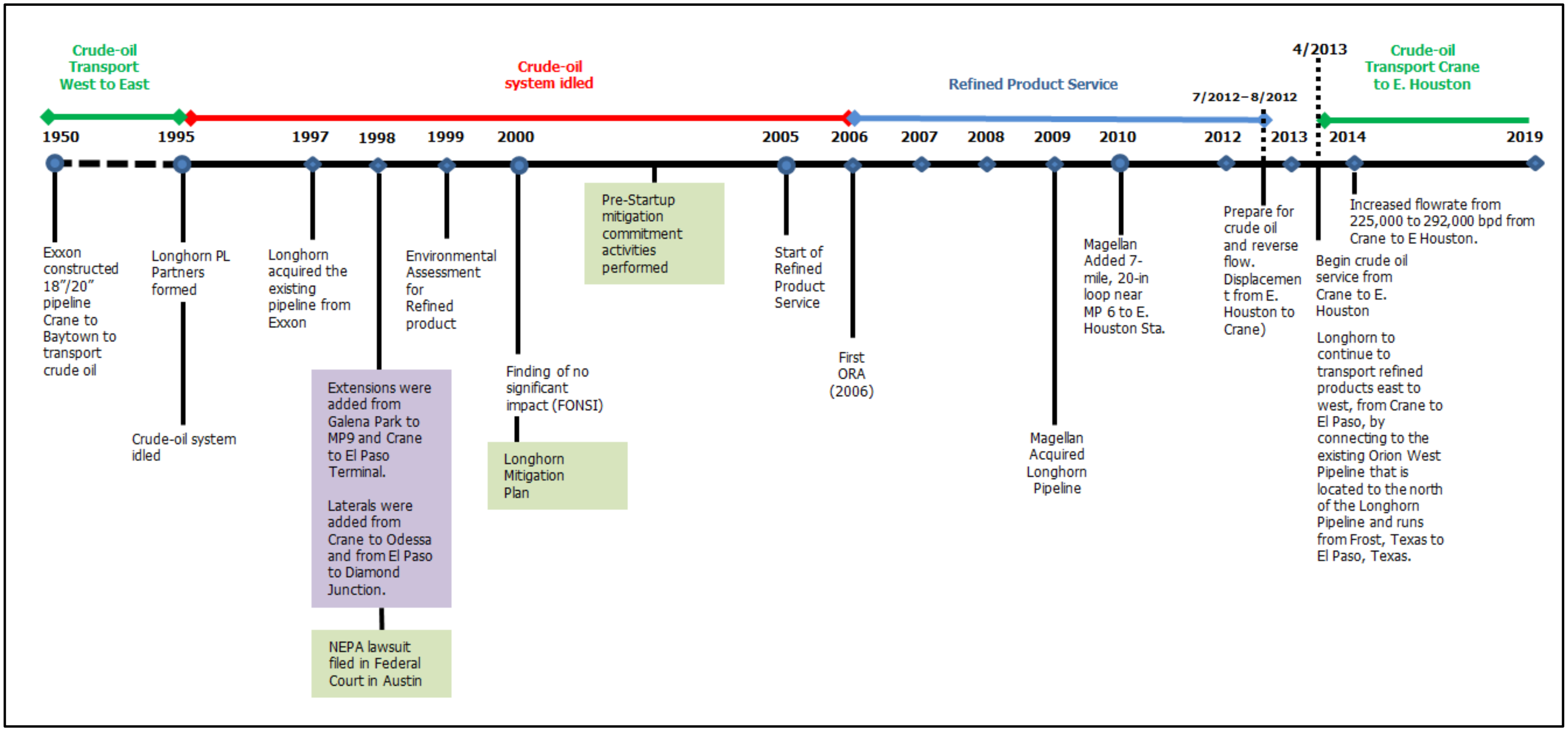

Figure 5. Timeline of the Longhorn Pipeline System

2 ORA ANALYSES AND LONGHORN MITIGATION PLAN REQUIREMENTS

The LMP monitors the following threats for the ongoing integrity of the Longhorn pipeline: pressure-cycle-induced fatigue cracking, corrosion, pipe laminations and hydrogen blisters, earth movement, TPD, SCC, and threats to facilities other than line pipe. In 2019, there were three assessments performed and received and two additional reports were received for ILI assessments performed in late 2018. The two segments assessed in 2018 and reports received in 2019 were Crane to Texon and El Paso to Strauss. The El Paso to Strauss segment was assessed using T.D. Williamson's (TDW) magnetic flux leakage (MFL) tool while the Crane to Texon segment was assessed using the Baker Hughes, a General Electric company, (BHGE) Magnescan (MF4) tool. For the 2019 assessments; two segments (Satsuma to E. Houston and Warda to Buckhorn) were assessed using BHGEs MF4 tool and one segment (E. Houston to Speed Jct) used TDW's gas magnetic flux leakage (GMFL) tool. Three segments (Crane to Texon, Warda to Buckhorn, and Satsuma to E. Houston) were also assessed using BHGE's Ultrascan™ CD (UCD) tool. EGP assessments were run on four segments of the Longhorn crude system; one in late 2018 and three in 2019. One EGP assessment was performed on the Longhorn refined system. The EGP assessments were performed using TDW's Deformation tool. Refer to Table 2 for a list of assessments performed in 2019 by pipeline segment.

Table 2. Longhorn System ILI Assessments

East Houston to Speed Jct	Satsuma to East Houston	Warda to Buckhorn	Crane to Texon		El Paso to Strauss
0.0 to 10.8	**34.1 to 2.4**	**112.9 to 68.0**	**457.5 to 416.6**		**0.0 to 9.4**
Corrosion					
GMFL	MFL	MFL**		MFL*~	MFL*
8/28/2019	8/13/2019	11/5/2019		10/16/2018	10/25/2018
Pressure Cycle Induced Fatigue					
	UCD	UCD**	UCD*		
	8/16/2019	11/8/2019	10/19/2018		
Third-Party Damage					
Deformation	Deformation	Deformation**	Deformation		Deformation*
8/28/2019	8/13/2019	11/5/2019	2/13/18 & 10/16/2018~		10/25/2018

*Assessments were performed in 2018 with final reports received in 2019.
**Final reports were received in 2020 and analysis will be included in the 2020 ORA Report.
*~The MFL assessment for Crane to Texon was included in the 2018 ORA Report.
~Two deformation assessments performed by different tool vendors (one by GE and one by TDW).

2.1 Pressure-Cycle-Induced Fatigue

Linear indications could potentially enlarge in service due to fatigue if subjected to pressure cycling loads sufficient to cause crack growth. Longitudinal seam flaws that may be affected by pressure cycles are more prevalent in pipes manufactured using older welding technology such as low frequency electrical resistance weld (LF-ERW) and flash welded (FW) pipe. Also, pipe seams in vintage pipes manufactured prior to 1970 typically exhibit low toughness compared to pipes produced using modern welding technology. As a result, manufacturing flaws in or 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 could 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 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 reach a critical size.

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 has been found to correspond reasonably well to the value of "upper-shelf" energy as determined utilizing standard Charpy V-notch impact tests. As noted in Reference [1], the full size, 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. When using hydrostatic test pressure, 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. However, no starting flaw sizes determined by hydrostatic test pressure were used in this analysis.

Toughness is not a factor in establishing either starting defect size using the ILI detection threshold, the N10 notch (the basis for an initial flaw size from API 5L) or crack detection (CD) tool indicated sizes. 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. All starting flaw sizes for this analysis were based on inspection tool threshold for detection (Existing Pipeline), API Specification 5L N10 notch size (New Pipeline) or crack detection tool reported indication sizes (inspected segments).

The fatigue assessment methodology involved:

- Operating pressure data processing using Rainflow cycle counting.
- Segmentation of the pipeline to account for pipe properties and attribute changes including outside diameter, grade, wall thickness, and elevation changes.
- Establishment of initial crack sizes from the detection threshold from the ILI vendor performance specification, ILI-indicated dimensions, or API inspection parameters.

- Determination of the final sizes of flaws at failure or critical size (predicted burst pressure equal to the MOP of the pipeline segments adjusted for elevation at the location of the segment analyzed).
- Fatigue crack growth assessment using fracture mechanics principles.
- Estimate time taken for both ILI-indicated and hypothetical threshold anomalies to grow to critical size.

2.1.1 Pressure Cycle Processing

Magellan supplied one-year of operational pressure data for the crude oil pipeline system from Crane Station through Satsuma Station, receipt point at East Houston Terminal, discharge point at the East Houston Station, and receipt point at Speed Jct. Pressure data in the same format was supplied for the refined products segments of the pipeline between Crane Station and El Paso Terminal. The pressure data used in the analysis were recorded at the discharge, suction, and receipt points of stations and facilities. The pressure readings were recorded from January 1, 2019 to December 31, 2019 at 1-minute intervals. The pressure data supplied was added to pressure data from the previous analyses to create an operational pressure history for each segment.

Rainflow counting was used to prepare the pressure data for analysis. The pressure spectrum based on pressure records for each pump station was rainflow cycle-counted to reduce the stochastic signal into cycles that can be used in the fatigue model. The basic concept of the rainflow counting method is to determine the peaks and valleys of the randomly-varying pressure data and to eliminate the intermediate pressures that are between the peaks and valleys (smaller peaks and valleys are also recognized by the process). The cycle-counting analysis produces count and sequence of cycles of various amplitudes which are then used with crack-growth calculation schemes. Kiefner's rainflow cycle counting process complies with ASTM E-1049 guidelines for rainflow counting methods.[5]

Due to the density of liquid products, elevation changes impact the internal pressure loading of the pipe due to hydrostatic head losses and gains. Data for the intermediate locations between the pressure measurement locations were calculated based on elevation changes and the hydraulic pressure gradient.

The pressure cycle data recorded since the date of the ILI inspection were used in the fatigue evaluation of pipeline segments for which the starting crack size was based on the crack detection tool inspections. For the 2019 analysis, the pressure cycles from October 19, 2018 through December 31, 2019 were used for the Crane to Texon segment, and pressure cycles from August 16, 2019 through December 31, 2019 were used for the Satsuma to East Houston segment.

2.1.2 Initial Flaw Size

The Eastern section of the Longhorn pipeline system that carries crude oil from Crane Station to Satsuma Station was internally inspected by General Electric (GE) in 2015 using a TFI tool to detect and size narrow axial indications such as linear indications in the longitudinal seam of

[5] ASTM, "Standard Practices for Cycle Counting in Fatigue Analysis", E 1049, Annual Book of Standards, 2002.

ERW and FW pipe. The segment from Satsuma to Speed Junction was inspected by TDW in 2014 using their SMFL technology to detect and size longitudinal seam flaws. The segment of the line between Crane and Texon was inspected using a UCD tool in late 2018 and the results of this inspection were provided in 2019. Similarly, the segment between Satsuma and East Houston was inspected using a UCD tool in 2019.

The fatigue assessment was conducted for 107 points along the segments of the crude oil portion of the pipeline between Texon and Satsuma and between East Houston and Speed Junction. Each of these points corresponds to a pipe property change including OD, grade, wall thickness, elevation, proximity to pump station discharge, and date of installation.

For Existing Pipeline segments (1947 to 1953 pipe material) the initial flaw sizes were determined by the threshold detection limit of TFI or SMFL inspections. Pursuant to the procedure in Section 3.4 of the ORAPM, 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 tool can detect seam weld features with a depth of 50% WT for features between one and two inches in length and a minimum depth of 25% WT 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. A 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.

Although the likelihood of such flaws being present in the newer pipe material (1998, 2010, 2012, and 2013) is much less than that associated with the 1950 pipe material, pressure-cycle monitoring and crack-growth analyses were considered for the New Pipeline. A slightly different procedure is applied to the calculation of time to failure for the new pipe installed from 1995 through 2013 including the entire western refined products section of the line from Crane to El Paso and the segments of the crude line between Texon and Satsuma and between East Houston and Speed Junction. Instead of using the sizes of flaws detected by the TFI tool, the starting flaw size was based on the largest flaw that could have escaped detection by the manufacturer's ultrasonic seam inspection. That would be the size of the "calibration" flaw used to test the ultrasonic seam inspection detection threshold. The calibration flaw size comes from API Specification 5L and 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 of locations containing newer pipe.

Locations near a pump discharge typically tend to experience more aggressive pressure cycles than locations away from the pump discharge. For the purpose of the current analysis, where pipe with similar attributes (grade, wall thickness, and other attributes) were present in a given Discharge-Suction/receipt segment, the pipe closest to the upstream pump station was used in the analysis. 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 as long as its difference in elevation, relative to upstream locations, is not significant.

The recent crack detection ILI conducted on the Crane to Texon and Satsuma to East Houston segments allowed the calculation of fatigue life based on the inspection results. The inspection of the Crane to Texon segment resulted in 397 indications that remained in the line after repairs and 335 indications were identified on the Satsuma to East Houston segment. The starting point for fatigue analysis on these two segments of the pipeline was the size of the anomalies reported.

A complete summary of the pipe segments evaluated as part of this study is presented in Appendix D – Threshold Anomaly Fatigue Evaluation Results and Appendix E – Crack Detection ILI Anomaly Fatigue Evaluation Results. The case locations were chosen with reference to the operating direction and pump locations as of 2019. The analysis was performed using pressure data collected from the most recent ILI inspections to December 2019.

2.1.3 Fatigue Crack Growth Assessment

To conduct a pressure-cycle analysis for the Longhorn Pipeline, the well-known and widely accepted "Paris Law" model was used. The crack-growth calculations were performed using Kiefner's Pipelife software.[6] Pipelife uses the Paris Law[7] equation, $da/dN=C(\Delta K)^n$, to estimate the incremental crack growth for a given feature in response to the pressure cycles counted from the rainflow method; where da/dN is the increment of crack growth per load cycle, ΔK is the range of cyclic stress-intensity at the crack-tip, and C and n are material crack-growth parameters. The cyclic stress intensity factor was determined using the Newman-Raju equation.[8] Details of these equations are available in the Mock ORA (Reference [2]). The pressure cycles were applied, and crack growth was calculated until failure was predicted at the MOP at the feature location. The cumulative number of pressure cycles at failure was then converted to a time to failure in years based on the interval over which the pressure data were collected. The fatigue life is the time in years for the defect to grow from the initial crack size to the final critical size. 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) as specified in the ORAPM.

The material-parameter constants used in the Paris equation affect the amount of crack growth that is calculated in response to a given pressure cycle. The constants are commonly referred to as the "crack-growth rate" parameters. These parameters 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 that are published in the Fitness-For-Service API Standard 579-1/ASME FFS-1[9] were used.

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[6] Kiefner, J. F., Kolovich, C. E., Wahjudi, T. F., and Zelenak, P. A., *"Estimating Fatigue Life For Pipeline Integrity Management"*, Paper Number IPC04-0167, Proceedings of IPC 2004, International Pipeline Conference, Calgary, Alberta, Canada (October 4 - 8, 2004).
[7] Paris, P. C. and Erdogan, F., *"A Critical Analysis of Crack Propagation Laws"*, Transactions of the ASME, Journal of Basic Engineering, Series D, Vol. 85, No. 5, pp 405-09.
[8] Newman, J.C. and Raju, I.S., "An Empirical Stress-Intensity Factor Equation for the Surface Crack", Engineering Fracture Mechanics, Vol 15, No 1-2, pp. 185-192, 1981.
[9] API RP 579-1/ASME FFS-1, Fitness-For-Service, Third Edition, 6/1/2016

The time to failure and reassessment intervals estimated by Kiefner can be used by Magellan to reassess the integrity of the pipeline as required and in accordance with the LMP.

2.1.4 Fatigue Assessment Results

Table 3 shows the segments with a predicted reassessment interval of less than 10 years for flaws potentially present in the pipeline. The pressure cycle data since the most recent ILI tool run for each segment were used in the fatigue evaluation. A safety factor of 2.22 was applied to the calculated time to failure for each of the postulated flaws to determine a reassessment interval.

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 16.39 years (from August 11, 2015) on the Texon to Barnhart segment. The shortest time to failure occurred on an 18-inch, 0.250 WT, Grade X52 pipe that was installed in 1953 and located at Station Number 21999+54. Applying a factor of safety of 2.22, a reassessment interval of 7.38 years is recommended based on the current operating pressures. This reassessment interval is relative to the latest inspection date of August 11, 2015. Calculated reassessment intervals for all of the threshold indications that could have been missed by the 2015 TFI tool run are Appendix D – Threshold Anomaly Fatigue Evaluation Results along with the results for API N10 size features.

The shortest time to failure predicted for the newer installed pipe was 345 years with a reassessment interval of 155 years. This hypothetical API N10 size flaw was evaluated at Station Number 0+02 in the East Houston to 9th Street segment of the line on 20-inch OD, 0.375-inch WT Grade B pipe installed in 2010. These results suggest that the newer pipe is unlikely to be susceptible to pressure-cycle induced fatigue crack growth if future operation is similar to, or less aggressive, compared to historical operation.

The shortest calculated time to failure for indications reported from the recent UCD ILI is 25.2 years resulting in a reassessment interval of 11.4 years from the date of inspection. The indication that this reassessment interval is based on was reported by the ILI tool to be 0.91 inch deep and 4.47 inch long in 18-inch OD, 0.246-inch WT, Grade X52 pipe at Station Number 23466+39 in the Crane to Texon segment. The calculated reassessment interval for the remainder of the indications reported by the UCD ILI was greater than 14 years. Calculated reassessment intervals for all of the indications reported by the UCD ILI are included in Appendix E – Crack Detection ILI Anomaly Fatigue Evaluation Results.

The results for the crude segment of the pipeline remained relatively consistent with the 2018 assessment performed by Kiefner. This suggests that pressure cycling for this pipeline has not changed significantly since the 2018 Kiefner assessment. Table 4 compares the results from the current 2019 fatigue assessment with those from the previous assessments.

Table 3. Predicted Time to Failure Less than 10 Years

Pipeline Segment	OD (inch)	WT (inch)	Yield Stress (psi)	Defect Location (feet)	Elevation (feet)	Calc. Time to Failure (years)	Re-assessment Interval (years)	Re-assessment Due Date	ILI Date
Texon-Barnhart[1]	18	0.250	52,000	21999+54	2,675	16.4	7.4	12/28/2022	8/11/2015
Cartman-Kimble[1]	18	0.281	45,000	18168+81	2,445	19.6	8.9	7/4/2024	8/29/2015
Bastrop-Warda[1]	18	0.281	45,000	7483+48	395	19.2	8.7	8/9/2024	12/11/2015
James River-Eckert[1]	18	0.281	45,000	13733+47	1,705	21.5	9.7	4/30/2025	8/19/2015

[1]Evaluation based on ILI threshold anomaly size

Table 4. Comparison of Reassessment Dates from Past ORAs

Segment	2015 Report	2016 Report	2017 Report	2018 Report	2019 Report
East Houston to 9th Street Jct	5/15/2214	8/23/2202	7/11/2174	3/15/2195	3/23/2170
Satsuma to East Houston	9/14/2027	11/14/2032	4/1/2035	9/7/2034	4/3/2084*
Buckhorn to Satsuma	6/15/2028	1/31/2039	3/1/2034	10/17/2034	5/5/2034
Warda to Buckhorn	12/27/2020	10/23/2027	11/23/2027	9/19/2030	3/6/2030
Bastrop to Warda	6/16/2020	4/7/2025	4/5/2024	10/6/2024	8/9/2024
Cedar Valley to Bastrop	3/6/2039	8/13/2046	2/9/2040	3/8/2044	8/8/2043
Eckert to Cedar Valley	8/1/2023	9/30/2033	8/9/2034	10/7/2032	9/12/2031
James River to Eckert	7/9/2027	11/5/2023	6/27/2025	3/28/2025	4/30/2025
Kimble County to James River	9/25/2034	9/11/2027	8/28/2030	9/6/2027	10/28/2027
Cartman to Kimble County	11/23/2024	3/29/2022	10/20/2023	5/20/2024	7/4/2024
Barnhart to Cartman	12/16/2053	1/17/2040	4/22/2045	12/1/2036	10/22/2037
Texon to Barnhart	9/9/2024	7/23/2021	12/11/2022	12/25/2022	12/28/2022
Crane to Texon	4/24/2023	4/13/2022	10/14/2027	1/28/2023	8/7/2025*
Crane to El Paso	11/29/2238	11/29/2238	3/22/2109	1/4/2498	1/4/2498

*Based on as-called ILI indication sizes.

2.2 Corrosion

Current ILI assessments were reviewed with an understanding of the background and approach for API 1163 ILI verification. API 1163 Second Edition, April 2013 describes methods in Section 7 and 8 that can be applied to verify that the ILI tool was performing as expected and reported inspection results are within the performance specification for the pipeline being inspected. For further background and approach on API 1163 Section Edition, April 2013 refers to Appendix C – Approach to API 1163 Verification.

For each assessment listed in Table 2, process verification and quality control were reviewed. The general results for all of the 2019 ILI assessments were that the functionality of the ILI inspection tools was determined to be within normal standard operating conditions and the locating of reference points by the ILI tool were determined to be consistent over the entirety of the ILI assessments.

The threat of corrosion can be monitored using ILI assessments, which 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. ILI assessments completed in 2019 are listed in Table 2. An overall ILI reassessment schedule can be found in Section 6, Table 33 for the crude system and Table 34 for the refined system. The next crude system assessment for corrosion is in 2020 for the Barnhart to Texon segment. The next refined system assessment for corrosion is due in 2021 for the 8-inch Crane to Odessa segment.

A run-to-run comparison was performed to determine external and internal corrosion growth rates (CGRs) for the ILI assessments performed or received in 2019. The three segments reviewed are: El Paso to Strauss, Satsuma to East Houston, and East Houston to Speed Jct. Each segment had a previous ILI assessment performed in 2014. The overall matched results from the run-to-run comparison are shown in Table 5. The run-to-run comparison indicated external/internal ML feature mismatches between the 2019 and 2014 assessments. There are no pipe replacements with reported metal loss features between the current and previous assessments. CGRs were calculated for the three pipeline segments and are shown in Table 6. There were not enough data pairs to support CGR calculations for internal ML features and internal ML mill anomalies on the El Paso to Strauss segment nor the internal ML mill anomalies on the E. Houston to Speed Jct segments. Data correlation and calculations were done using Kiefner's CorroSure software.

Table 5. Overall Results of the Run-to-Run Comparisons

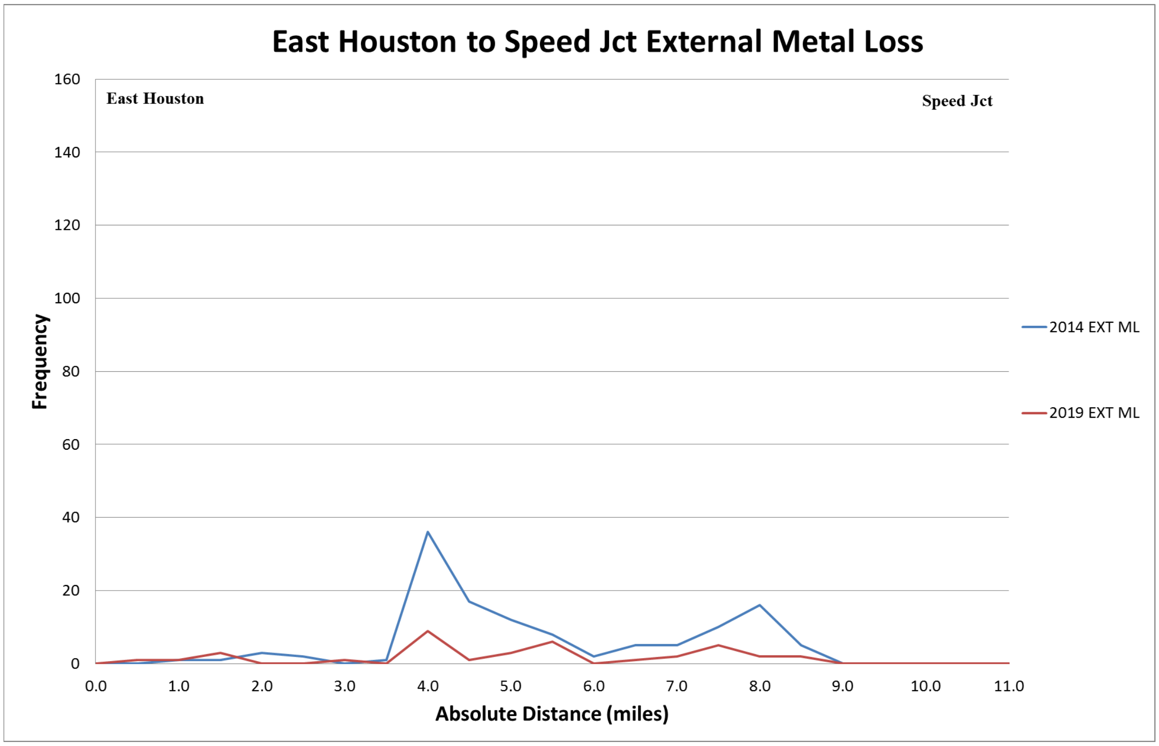
Segment	Matched Features		Total Matched Features	Maximum Available Matches	% Matched Features
	Corrosion	Manufacturing			
El Paso to Strauss	10	N/A	10	16	62.5
Satsuma to East Houston	2358	36	2394	5040	47.5
East Houston to Speed Jct	237	N/A	237	485	48.9

Table 6. Corrosion Growth Rate Results for 2019 ILI Assessments

Segment	Upper Bound CGR (mpy)			
	EXT ML	INT ML	EXT/INT ML Mismatches	INT ML Mill Anomalies
El Paso to Strauss	5.4	N/A	N/A	N/A
Satsuma to East Houston	13.1	9.0	7.7	11.7
East Houston to Speed Jct	6.4	2.5	2.3	N/A

External corrosion growth 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 ML frequency (occurrences or count) along the linear distance of the pipeline can indicate where external ML features are more likely. Figure 6 through Figure 10 provide external ML frequency histograms for the 4 segments assessed in 2019; internal ML frequencies were also reviewed and are shown in the figures.

- Figure 6 and Figure 7 shows histograms for East Houston to Speed Jct; Figure 6 shows the external and internal ML features broken out separately while Figure 7 shows the external and internal ML features combined. Figure 7 indicates the ML count between assessments is similar and that there is a difference in how external and internal features were reported between the two assessments. There are 49 internal ML features from the 2019 assessment that correlate with external ML features from 2014.
- Figure 8 and Figure 9 show histograms for Satsuma to East Houston; Figure 8 shows the external and internal ML features broken out separately while Figure 9 shows the external and internal ML features combined. Figure 9 indicates the 2019 ILI assessment is reporting more ML features overall than the 2014 ILI assessment and also indicates that there is a possible difference in how external and internal features were reported between the two assessments. There are 23 external ML features from the 2019 assessment that correlate with internal ML features from 2014 and 745 internal ML features from the 2019 assessment that correlate with external ML features from 2014.
- Figure 10 shows histograms for El Paso to Strauss. Figure 10 is showing similar ML feature counts between the two ILI assessments. All ML features from both assessments (2014 and 2019) had reported depths ≤18% WT. Due to the low level of corrosion and the tool tolerance (±10% WT) there are a couple of areas where one assessment reported a ML feature, and the other assessment did not report a feature; example between MP 6.0 and 7.0. There is one external ML feature from the 2019 assessment that correlate with an internal ML feature from 2014 and one internal ML feature from the 2019 assessment that correlate with an external ML feature from 2014.



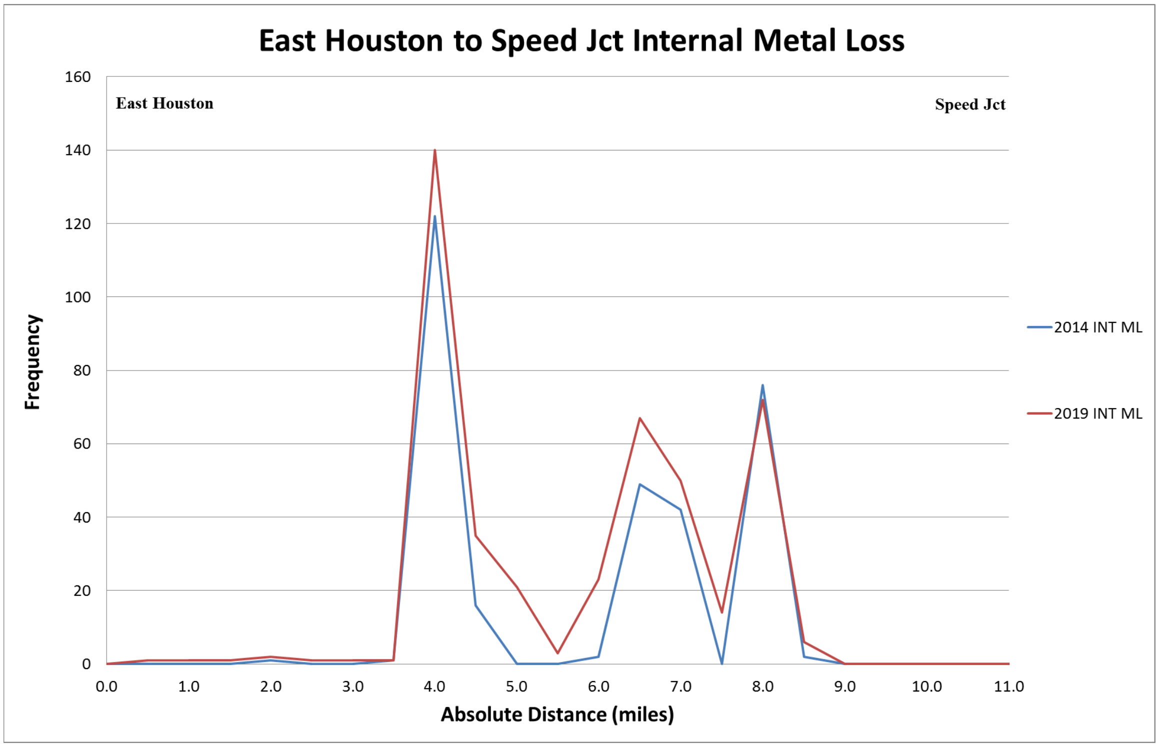


Figure 6. East Houston to Speed Jct ML Frequency by Linear Distance along the Pipeline (2014 MFL vs 2019 MFL)

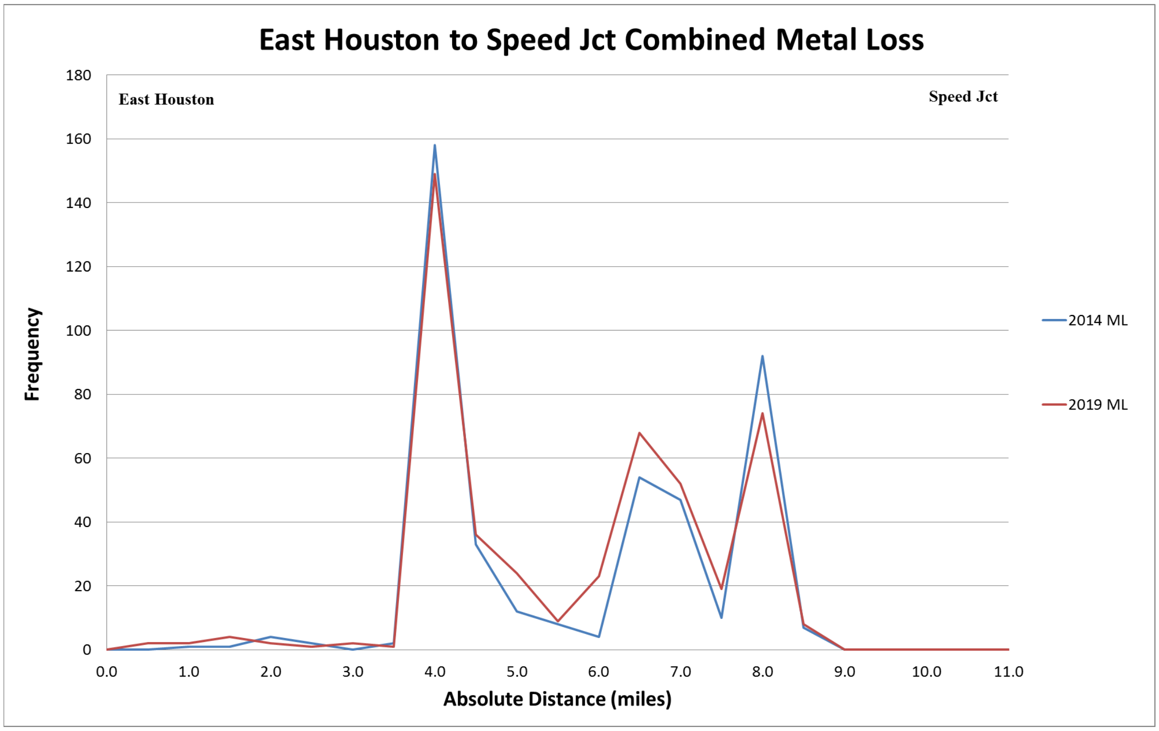
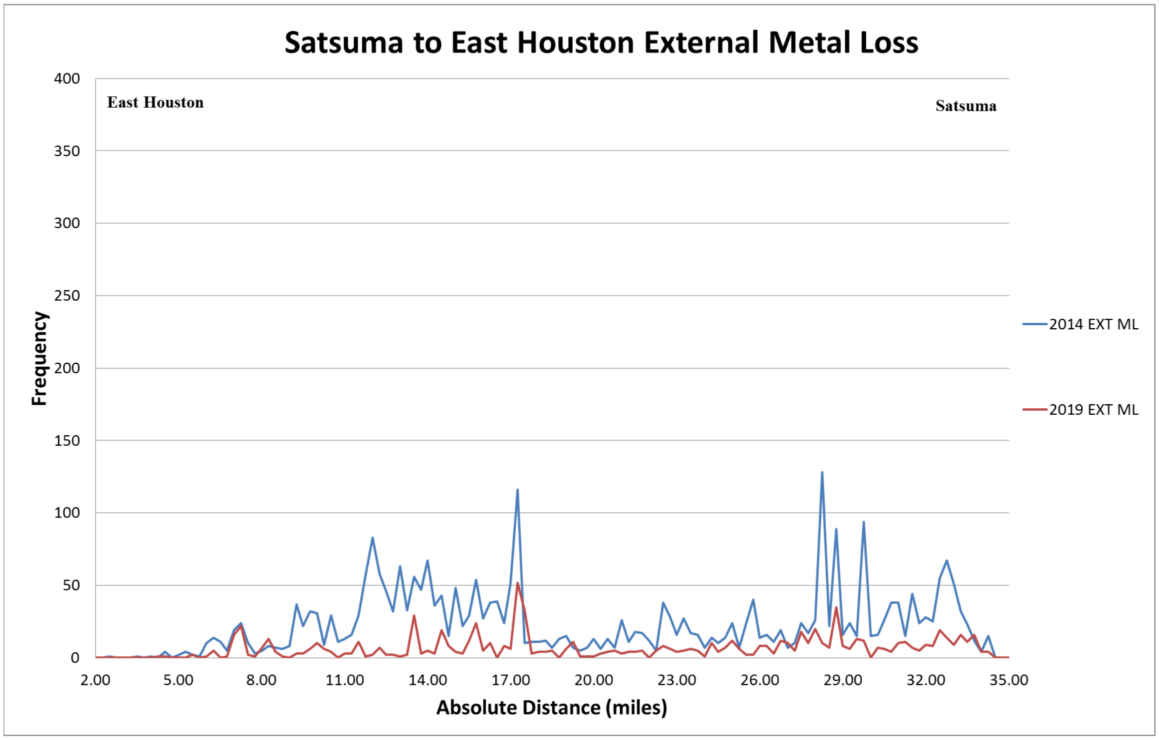


Figure 7. East Houston to Speed Jct Combined ML Frequency by Linear Distance along the Pipeline (2014 MFL vs 2019 MFL)



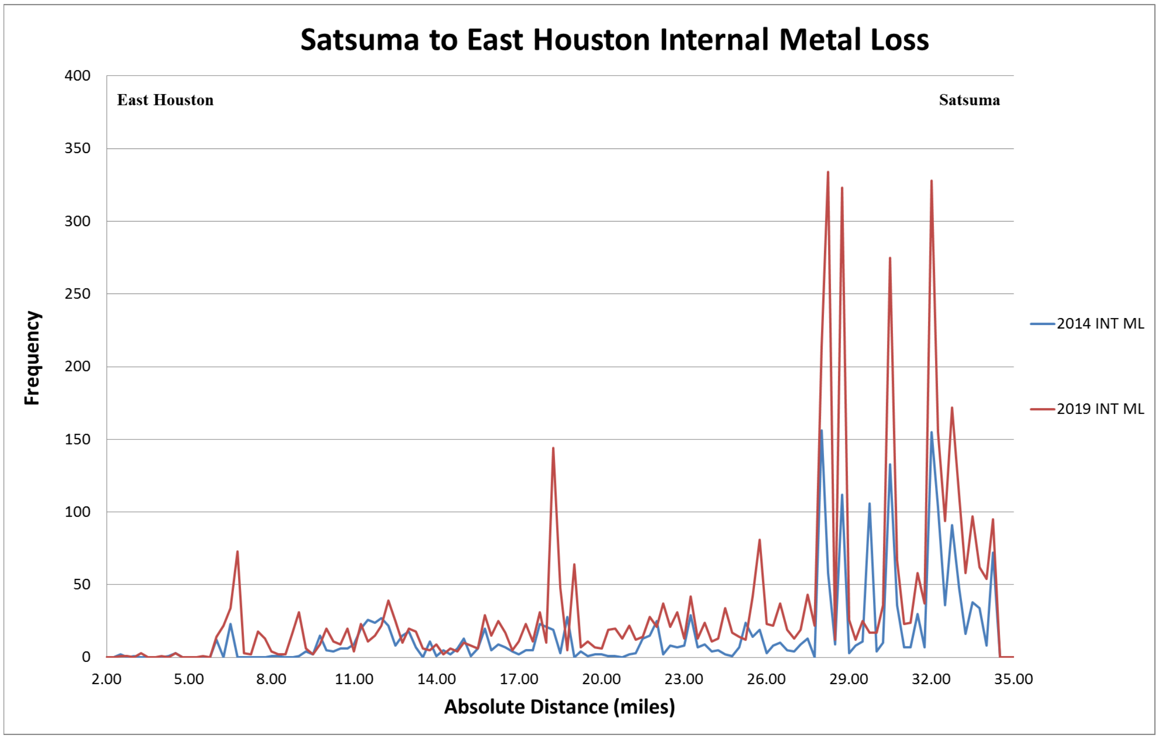


Figure 8. Satsuma to East Houston ML Frequency by Linear Distance along the Pipeline (2014 MFL vs 2019 SMFL)

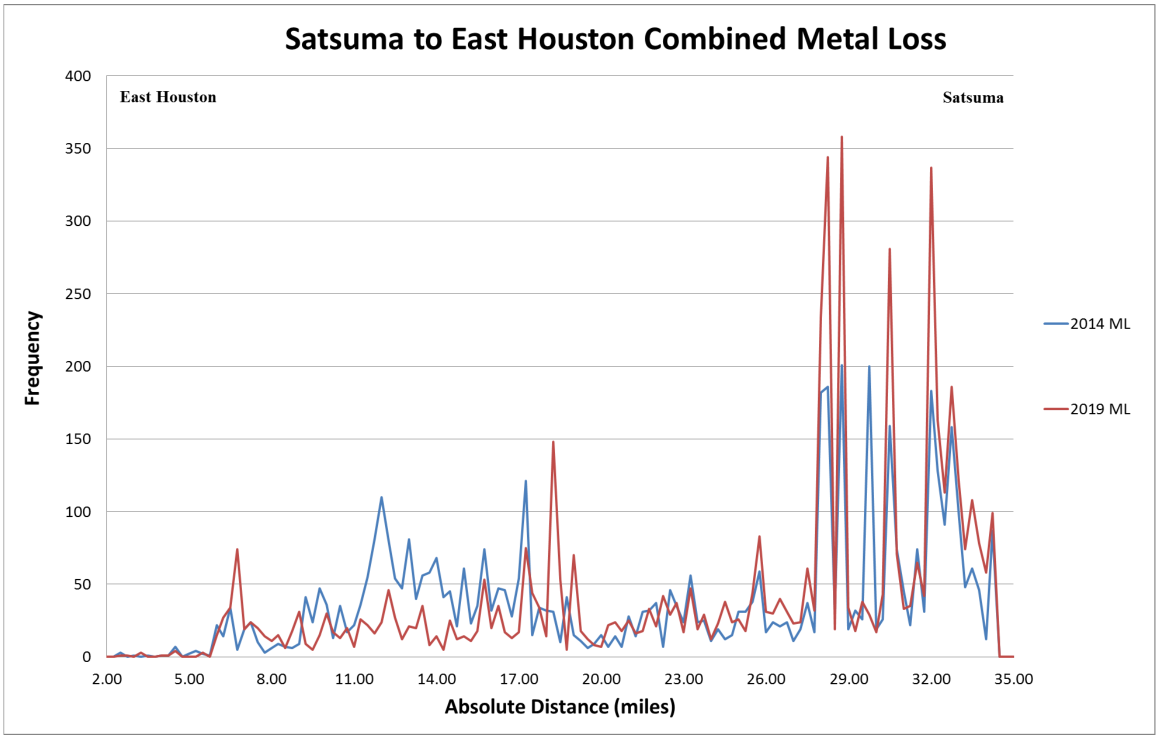
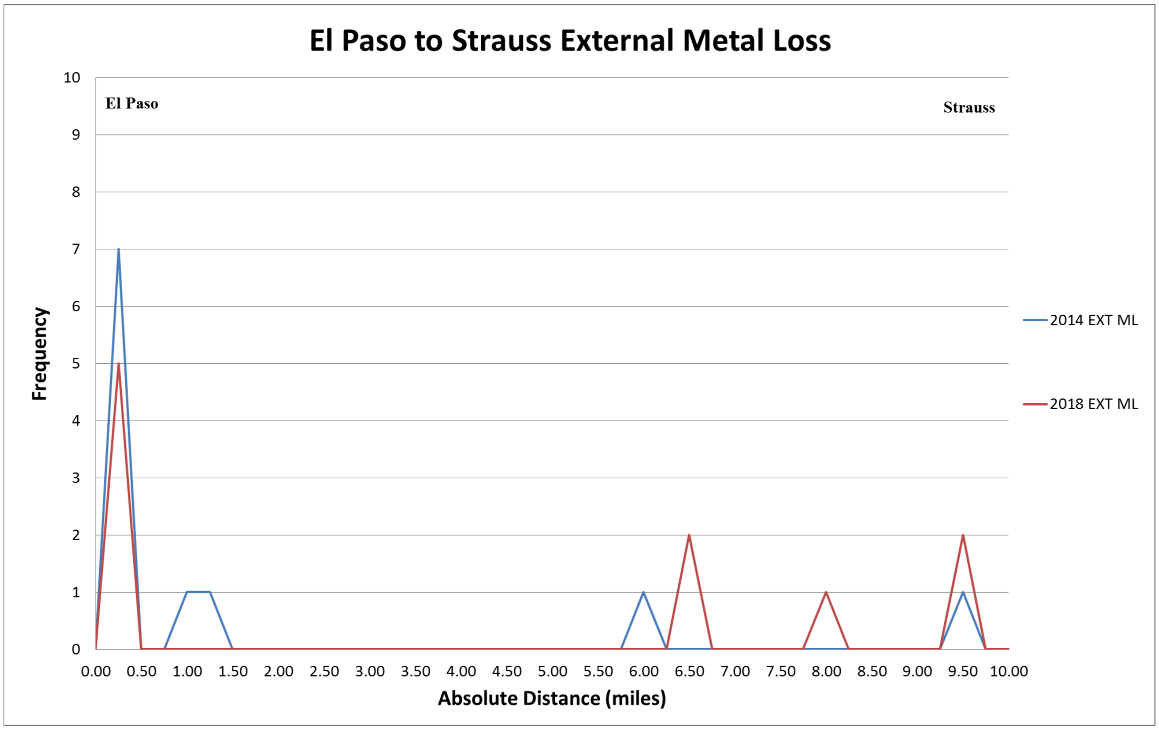


Figure 9. Satsuma to East Houston Combined ML Frequency by Linear Distance along the Pipeline (2014 MFL vs 2019 SMFL)



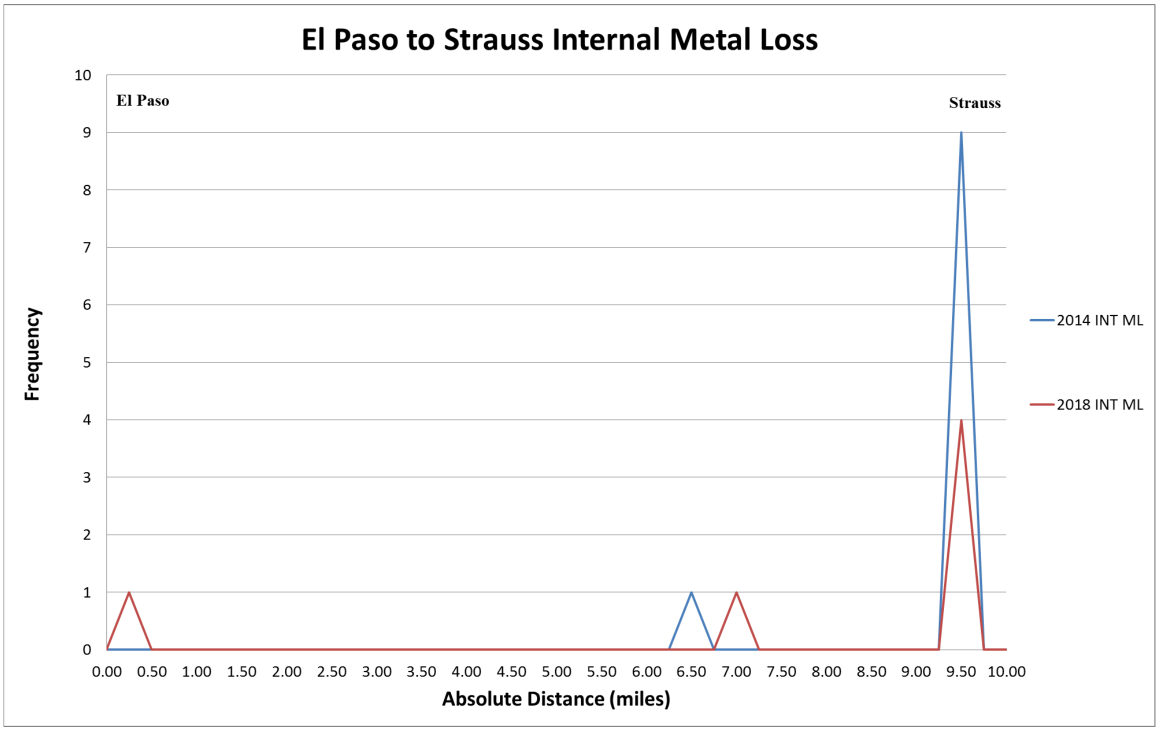


Figure 10. El Paso to Strauss ML Frequency by Linear Distance along the Pipeline (2014 MFL to 2018 MFL)

Crack features identified from the 2018/2019 UCD assessments were correlated with crack features reported from SMFL and TFI assessments. The two segments reviewed are: Crane to Texon (2015 TFI to 2018 UCD) and Satsuma to East Houston (2014 SMFL to 2019 UCD). Table 7 shows a breakdown of reported crack features between the current UCD assessments and the previous SMFL/TFI assessments. Fifty-five cracks reported from the current UCD assessments were found to either correlate or be present on the same joints with cracks reported from the 2014/2015 assessments; Table 8 provides a breakdown of the correlations. One feature on the Crane to Texon segment is noted as being located under a sleeve. The matched and unmatched feature quantities provided in Table 8 are based on the 2018/2019 UCD assessments.

Table 7. UCD Reported Feature Comparison

Segment	Features Reported by UCD							
	2019			2014 / 2015				
	Crack-Like	Crack Colony	Notch	SW Anomaly	SW Feature B	Seam Variation	Axial ML Feature in Long Seam	EXT/INT SWML
Crane to Texon	468	6	22	210	4	-	13	31
Satsuma to East Houston	354	2	1	-	-	44	2	92

Table 8. UCD Crack Feature Correlations[10]

Segment	Quantity			List of Joints with Correlated Features*
	Joint(s)	Matched Crack Features	Unmatched Crack Features	
Crane to Texon	20	10	29	2920, 3280, 3970, 4190~, 7350, 9130, 10390@,10470, 11550**, 12810, 17610#, 17950, 18340, 19730, 20170, 20520, 22300^, 38820#, 39110^, 43650
Satsuma to East Houston	10	11	5	1710, 2260, 2470#, 3570, 4860, 7750, 12880, 22860, 24050, 29330
Total	**30**	**21**	**34**	

*The listed joint numbers are from the current UCD assessment.
**Matched feature is reported under a sleeve.
~Two features were addressed in 2019 and one feature was addressed previously.
@Two features have been previously addressed.
^One Feature has been previously addressed.
#Features were addressed in 2019.

[10] Features may not be directly correlating (i.e. overlapping area), but were identified in this table if reported on the same joint.

2.2.1 Maintenance Reports and In-Ditch Evaluations

In 2019, Magellan performed 31 in-ditch ILI assessments which corresponded to current ILI assessments (2018 MFL/UCD and 2019 MFL). Anomaly investigations also included nondestructive evaluation (NDE) reports with detailed investigation results. Fifty-six maintenance reports and 18 positive material identification (PMI) reports were received for 2019; Table 9 provides a breakdown of the assessment types addressed in the maintenance reports. Table 10 provides a breakdown, per pipeline segment, of where the maintenance occurred (HCA, segment, and tier). The total number of ILI anomalies addressed, per pipeline segment in 2019, is listed in Table 11; the total number includes the targeted ILI anomalies and any anomaly found in the area of repair for that associated dig.

Magellan requires PMI[11] tests to be completed at 50% of the ILI anomaly investigation locations that do not have material documentation. In 2019; 31 ILI anomaly investigations were performed and all 31 locations met the PMI requirement. Magellan performed PMI testing at 18 of the 31 anomaly investigation locations (58%) which satisfies PMI requirements. Table 12 gives an overview of PMI testing since the requirement to perform PMI testing was added in the 2014 ORA.

Table 9. Maintenance Report Items

Maintenance Report Items	Number
Anomaly Investigation	31
Investigate Exposed Pipe	1
Foreign Line Crossing	7
New Foreign Pipeline Crossing	3
New Powerline Crossing	1
New Poly Pipeline	6
New Electric Steel Casing Crossing	3
New Electric Conduit Crossing	4
New Fiber Optic Cable Crossing	22
New Sprinkler System Crossing	3
New Gas Line Crossing	2
New Fence	2
New Water Line Crossing	1
New Drain Pipe Crossing	1

[11] 2012 Longhorn Pipeline Reversal EA (Reference [6]).

Table 10. ILI Features Remediated per Maintenance Reports Completed in 2019

	18" Cottonwood to El Paso	18" Crane to Cottonwood	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	8" Kinder Morgan Flush Line	8" El Paso to Kinder Morgan	12" El Paso to Kinder Morgan	8" Crane to Odessa
ILI Date	10/25/18		10/16/18									11/5/19		8/13/19	8/28/19					
Maintenance Report	Yes	Yes	Yes	Yes	Yes	No	No	No	No	No	Yes	Yes	Yes	Yes	No	No	No	No	No	No
Tier I	3	4	0	0	0	0	0	0	0	0	1	10	7	1	0	0	0	0	0	0
Tier II	0	0	3	6	1	0	0	0	0	0	0	1	9	5	0	0	0	0	0	0
Tier III	0	0	0	0	0	0	0	0	0	0	0	0	2	3	0	0	0	0	0	0
Total Digs	3	4	3	6	1	0	0	0	0	0	1	11	18	9	0	0	0	0	0	0
HCA	1	1	0	0	0	0	0	0	0	0	0	0	13	9	0	0	0	0	0	0
Non-HCA	2	3	3	6	1	0	0	0	0	0	1	11	5	0	0	0	0	0	0	0

Table 11. Reported ILI Anomalies Excavated per 2019 ILI Anomaly Investigation Reports

ILI Anomaly Called	Number of Anomalies Addressed	18" Cottonwood to El Paso	18" Crane to Cottonwood	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
External ML	**5**	0	0	2	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0
External ML associated w/Lamination	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Internal ML	**3**	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0
Internal ML crosses Long Seam	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Anomaly w/ML	**2**	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crack-like feature at SW	**39**	0	0	32	0	0	0	0	0	0	0	0	0	0	7	0	0	0	0
Crack-like feature at GW	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crack Colony at Pipe Body	**4**	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Notch-like at Seam Weld	**9**	0	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ID Reduction w/associated ML	**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 – 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
Geometric Anomaly	**2**	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geometric Anomaly associated w/Mill Anomaly	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geometric Anomaly associated w/ML	**2**	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0
Girth Weld Anomaly	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion External	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lack of Fusion Mid-wall	**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	**4**	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamination Intermittent associated w/ML	**0**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seam 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
TOTAL	**70**	**0**	**0**	**55**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**0**

Table 12. Positive Material Identification Testing Activity

	Pipeline Segment	2014	2015	2016	2017	2018	2019
Refined System	8″ El Paso to Chevron	0	0	0	0	0	0
	8″ Crane to Odessa	0	0	0	0	0	0
	12″ El Paso to Kinder Morgan	0	0	0	0	0	0
	18″ Cottonwood to El Paso	0	0	0	0	0	0
	18″ Crane to Cottonwood	0	0	0	0	0	0
Crude System	18″ Crane to Texon	0	1	7	0	4	15
	18″ Texon to Barnhart	0	0	8	3	0	0
	18″ Barnhart to Cartman	0	0	11	0	0	0
	18″ Cartman to Kimble County	0	0	12	0	0	0
	18″ Kimble County to James River	0	0	5	0	0	0
	18″ James River to Eckert	0	1	3	0	0	0
	18″ Eckert to Cedar Valley	1	0	6	7	0	0
	18″ Cedar Valley to Bastrop	0	0	20	6	0	0
	18″ Bastrop to Warda	0	1	3	4	0	0
	18″ Warda to Buckhorn	0	2	0	14	0	0
	18″ Buckhorn to Satsuma	0	0	0	8	0	0
	20″ Satsuma to E. Houston	0	4	0	0	0	3
	20″ E. Houston to 9th Street Junction	0	0	0	0	0	0
Total PMI Tests Performed		**1**	**9**	**75**	**42**	**4**	**18**
Segments without available Material Documentation		**2**	**18**	**141**	**64**	**7**	**31**
Percentage Addressed (Requirement of 50%)		**50%**	**50%**	**53%**	**65%**	**57%**	**58%**

The 2018 MFL and UCD assessments for Crane to Texon and the 2019 MFL and UCD assessments for Satsuma to E. Houston were correlated with 2019 dig results found in the in-ditch ILI anomaly investigation maintenance and NDE reports. The ILI anomaly investigation digs resulted in 61 individually correlated features. A breakdown of the ILI anomaly investigation dig data correlations can be found in Table 13. Four laminations were identified during 31 ILI investigation digs. The ILI metal loss tool performance was not considered as there were not a statistically significant number of ML validation measurements available for either Crane to Texon or Satsuma to E. Houston.

In 2019, 28 out of the 31 ILI anomaly investigation digs targeted crack-like, crack colony, or notch-like features reported from the 2018/2019 UCD assessments on Crane to Texon and Satsuma to E. Houston. Table 14 shows the results for UCD reported crack-like features evaluated in-ditch. UCD reported crack-like features on Crane to Texon were found to be cracked in the field 26.7% of the time, found as lack of fusion (LOF) 20% of the time, and found as mill defects 53.3% of the time. The seven UCD reported crack-like features evaluated in-ditch on the Satsuma to E. Houston segment were all found as cracks in the field. Table 15 shows the results for UCD reported crack colony features evaluated in-ditch on Crane to Texon; crack colonies were found as cracks in the field 75% of the time and as a gouge 25% of the time. The UCD reported nine individual notch-like features that Magellan evaluated in-ditch in five digs on the Crane to Texon segment; all nine features were found in the field as individual mill defects.

Table 13. 2019 ILI Field Investigation Data Correlations

Pipeline Segment	EXT ML to EXT ML	EXT ML to Gouge	Geometric Anomaly to Dent/Gouge	Geometric Anomaly Associated with ML to Dent	Crack-Like Seam Feature to Mill Defect	Crack-Like Seam Feature in Heat Affected Zone to Mill Defect	Crack-Like Seam Feature (Possible Manufacturing) to Mill Defect	Crack-Like Seam Feature to Mid-Wall Crack	Crack-Like Seam Feature to OD Crack	Crack-Like Seam Feature to ID Crack	Crack-Like Seam Feature to OD Lack of Fusion	Crack-Like Seam Feature to Mid-Wall Lack of Fusion	Crack Colony (Pipe Body) to Mid-wall Crack	Crack Colony (Pipe Body) to Crack in Pipe Body	Crack Colony (Pipe Body) to Gouge	Notch-Like Feature with SW to Mill Defect	Lamination to Mid-wall Lamination	Total Data Correlations
8-in El Paso to Chevron	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
8-in Crane to Odessa	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
12-in El Paso to Kinder Morgan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cottonwood to El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Crane to Cottonwood	0	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	2	12	1	3	5	2	1	3	3	2	1	1	9	4	**51**
18-in Texon to Barnhart	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Barnhart to Cartman	0	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	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Kimble County to James River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in James River to Eckert	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Eckert to Cedar Valley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Cedar Valley to Bastrop	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Bastrop to Warda	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Warda to Buckhorn	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Buckhorn to Satsuma	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
18-in Satsuma to E. Houston	0	1	2	0	0	0	0	4	3	0	0	0	0	0	0	0	0	**10**
18-in E. Houston to Speed Jct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	**2**	**1**	**2**	**2**	**12**	**1**	**3**	**9**	**5**	**1**	**3**	**3**	**2**	**1**	**1**	**9**	**4**	**61**

Table 14. In-Ditch Dig Results for ILI Reported Crack-Like Features

Pipeline Segment	ILI Reported Features	In-Ditch Field Results			Percentages (%)		
	Crack-Like	Mill Defect	LOF	Crack	Crack-like to Mill Defect	Crack-like to LOF	Crack-like to Crack
Crane to Texon	30	16	6	8	53.3	20.0	26.7
Satsuma to E. Houston	7	0	0	7	0.0	0.0	100.0

Table 15. In-Ditch Dig Results for ILI Reported Crack Colony Features

Pipeline Segment	ILI Reported Features	In-Ditch Field Results		Percentages (%)	
	Crack Colony	Crack	Gouge	Crack Colony to Gouge	Crack Colony to Crack
Crane to Texon	4	3	1	25.0	75.0
Satsuma to E. Houston	0	0	0	-	-

2.2.2 ID Reductions

Magellan runs 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. ID reductions greater than or equal to 2% of the pipe diameter are referred to as dents. ID reductions less than 2% of the pipe diameter are referred to as GMAs.

The 2019 EGP assessments reported 227 ID reductions; 67 between Satsuma to East Houston, 154 between Crane to Texon, and 6 between El Paso to Strauss. Fourteen of the ID reductions are noted as being previously repaired. The remaining 213 ID reductions are classified as 11 dents and as 202 GMAs. One dent with associated metal loss was reported on Satsuma to East Houston was noted as repaired. Three GMAs located in an HCA on the Satsuma to East Houston segment were noted as being associated with metal loss. Nineteen GMAs were reported on Crane to Texon as interacting with a seam weld; one is noted as being previously repaired and none are located in an HCA. Two GMAs were reported on Crane to Texon as interacting with a girth weld and are not located in an HCA.

As shown in Table 16, 73 of the reported ID reductions are located within HCAs; with 11 noted as previously repaired. However, these ID reductions do not meet regulatory repair criteria (equal to or greater than 2% OD and interacts with a long seam or girth weld).

Table 16. ID Reductions Located within HCAs [12]

Segment	Quantity	Quantity Noted as Repaired	Peak Depth (% OD)	Comment
East Houston to Speed Junction	0	N/A	N/A	• N/A
Satsuma to East Houston	67	11	2.7	• All ID reductions reported in HCA with depths greater than or equal to 1.8% are noted as repaired.
Crane to Texon	0	N/A	N/A	• No HCA locations identified in pipeline listing.
El Paso to Strauss	6	0	1.4	• Pipeline listing identified these features as "Dents" but none were greater than 2.0% OD.
Total	**73**	**11**		

2.2.3 Laminations and Hydrogen Blisters

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. 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 internally in 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

[12] ID reductions are classified as either dents or geometric anomalies. A dent is an ID reduction greater than or equal to 2% OD and a geometric anomaly is an ID reduction less than 2% OD.

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. Elevated cathodic protection (CP) can also lead to hydrogen migration and hydrogen blistering. Managing internal corrosion and monitoring CP levels could help mitigate these threats.

ID reductions identified from the 2019 EGP assessments were correlated with laminations reported from the 2009/2010 UT assessments. One dent and 23 GMAs reported from the 2019 assessments were found to either correlate or be present on the same joints with laminations reported from the 2009/2010 UT assessments, shown in Table 17. Of those correlated features, one dent and four GMAs are noted as either having been previously repaired or marked as a dig within the ILI listing.

A review of the 2019 maintenance reports showed that no digs were scheduled as an ILI investigation dig due to a lamination. Four laminations were reported during in-ditch assessments in 2019. Monitoring reported laminations for ID reductions might indicate the initiation of a hydrogen blister. However, no blisters were found during the in-ditch assessments. Per the Longhorn EA Section 9.3.2.3, the monitoring frequency recommended should coincide with the EGP tool assessment schedule. EGP assessments are required for the Existing Pipe every three years in accordance with the LMP, with exception of the section between East Houston and Speed Junction. The next EGP assessment for the crude system is in 2020 for the Buckhorn to Satsuma segment, see Table 33.

Table 17. ID Reductions Correlating with Laminations[13]

Segment	Quantity			Peak Depth (% OD)	List of Joints	Comment
	Joint(s)	Dent(s)	GMA(s)			
East Houston to Speed Junction	N/A	N/A	N/A	N/A	N/A	• N/A
Satsuma to East Houston	12	1	16	2.7	9350, 14100, 16410, 16600, 16820, 16850, 21400, 21560, 21570, 26300, 29360, 29690	• The GMA on Joint 9350 is to be addressed by Dig # 60-1. • The Dent on Joint 14100 was repaired by Armor Plate. • The GMA on Joint 26300 was repaired by sleeve.
Crane to Texon	7	0	7	1.4	2950, 9480, 12800, 17700, 19860, 20720, 21810	• The GMA on Joint 2950 is to be addressed by Dig # MFL-1 • The GMA on Joint 17700 was repaired by sleeve.
El Paso to Strauss	N/A	N/A	N/A	N/A	N/A	• N/A
Total	**19**	**1**	**23**			

[13] Features may not be directly correlating (i.e. overlapping area), but were identified in this table if reported on the same joint.

2.3 Earth Movement and Water Forces

2.3.1 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. Those active faults are Akron, Melde, Breen, and Hockley faults, which cross the original Longhorn pipeline as well as, McCarty, Negyev, and Oates faults, which cross the new East Houston line constructed in 2012. The location and geologic data for these faults are summarized in Table 18.

Table 18. 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 were unavailable.

2.3.2 Allowable Displacements at Faults

Kiefner has conducted two series of stress analyses on the pipes to determine the allowable displacements at the faults, one in the 2005 ORA Report and one in the 2014 ORA Report. The original stress analysis in the 2005 ORA Report was conducted for Akron, Melde, Breen, and Hockley faults. Assumptions used in that analysis included: the allowable stress levels based on the version of ASME B31.4[14] 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; and soil properties were determined from the best estimate of obtainable properties.

In the 2014 ORA Annual Report, the allowable displacements at the McCarty, Negyev, and Oates faults were determined. Due to the high rate of movement and the relatively low allowable displacement at the Hockley fault, the stress analysis was repeated at this fault for the 2014 ORA Report. In the 2014 analysis, the stresses in the pipelines at various fault displacements were predicted through finite element analysis (FEA) with the same soil properties as were used in the previous 2005 analysis. The allowable fault displacement was then determined when the stress reached the allowable stress levels at the pipe based on the ASME B31.4-2012, which was the latest version at the time. In ASME B31.4-2012, the allowable longitudinal stress level increased compared to the previous versions from 54% SMYS to 90% SMYS. This new limit was

[14] 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.

considered for stress analysis of McCarty, Negyev, and Oates faults. Given the pipeline vintage of the Hockley fault, Kiefner opted for a lower limit of 80% SMYS to determine the critical displacement. Please see the 2014 ORA Report for details of the analysis.

2.3.3 Fault Movements

Monitoring stations across the Akron, Melde, Breen, and Hockley 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. Thirty-one subsequent displacement readings[15] have been taken at approximately 6-month intervals. A plot of the vertical displacements over time is shown in Figure 11. Magellan performed maintenance activities to relieve stress on the pipeline at the Hockley fault in 2019.

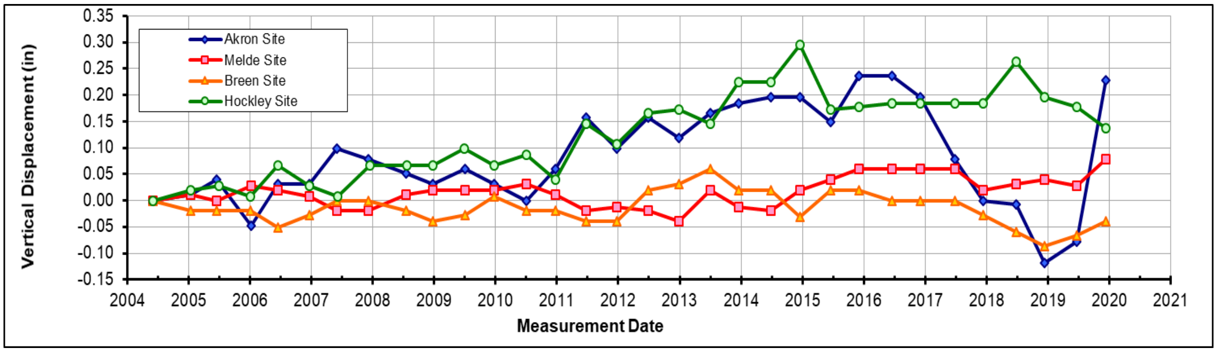


Figure 11. Fault Displacement over the 15.5 Year Monitoring Period at Akron, Melde, Breen, and Hockley Faults

In 2017 and 2018, there was a considerable amount of backward movement in the Akron fault in comparison to the previous 12 years of monitoring. This trend was followed by a rebound in 2019 when the fault approximately got back to its previous displacement prior to 2017. It should be noted that the readings measured in mid-December 2019[16] indicated an atypically large change in displacement between survey events (greater than 0.2 inches). This rate of movement requires close monitoring.

In 2019, the 30th and 31st resurveys[17] reported that the trend lines show no measurable movement for the Melde and Breen faults. Data collected at these faults since the benchmarks were installed in 2004 show slow progressive movement. At Breen fault, the backward movement which was started in mid-2017 and continued throughout 2018, was reversed in 2019 and resulted in the fault's final displacement getting closer to the mean position. However, the short-term trend at the Breen fault requires close monitoring. Regarding the Hockley fault, the recent resurveys indicate continuous movement above the average historical movements which suggest continuous monitoring is required at this fault.

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[15] Geosyntec Semi-Annual Fault Displacement Monitoring Reports. The last report is for the 2nd half of 2019.

[16] Reading was more than 5 millimeters different than the previous readings, so verification readings were collected on December 17, 2019 to confirm the results. Verification readings were consistent with the initial readings.

[17] Geosyntec – First-half and second-half Semi-Annual Fault Displacement Monitoring Reports.

In 2012, three additional faults were instrumented for the lines that were constructed to connect the existing Longhorn line to East Houston. 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 17 readings taken as shown in Figure 12.

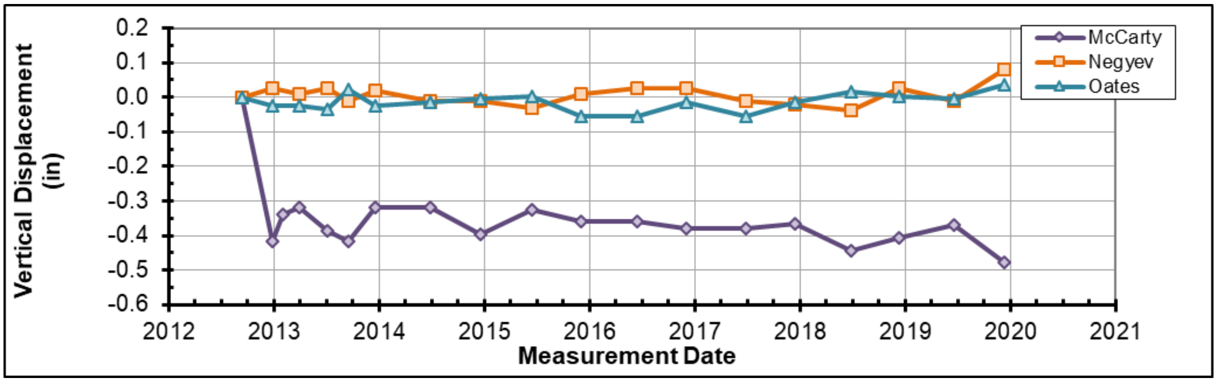

Figure 12. Fault Displacement over the 5.5 Year Monitoring Period at McCarty, Negyev, and Oates Faults

The readings measured at the McCarty station from the baseline measurement in September 2012 to December 2012 indicated a jump of about one-half inch of displacement had occurred. No other large movement has been observed subsequent to the initial jump. This jump could be indicative of the benchmark equilibrating with its environment after installation or due to measurement error of the baseline reading. Since 2018, the resurveys show continuous movement above the average at McCarty and Negyev faults that require continuous monitoring. The movement at Oates fault during 2019 followed the average trend line.

Table 19 shows the allowable displacement at each fault, the average rate of the movement calculated in three different ways, and the time to reach the allowable displacement based on those three rates. The average rate of movement for each fault is determined using the following three methods:

- Historical rate: By linear regression of the recorded fault movements over the whole monitoring period.
- Short-term rate: By linear regression of the recorded fault movements over the last two years. This reflects the short-term trend at the fault line and shows if new movement requires close monitoring or not.
- Current rate: By dividing the last recorded fault movement (plus measurement error) by the number of years monitored. This is another indicator that combines the long-term effect and the latest fault motion.

The time to reach allowable displacement for each fault shown in the last column of Table 19 is obtained by dividing the allowable displacement by the average rate of movement. This is the total time from when the pipe is free of stress (caused by fault movement) to the final failure.

Table 19. Summary of Estimated Allowable Fault Displacement at Faults

Fault	Allowable Displacement (inch)	Average Rate of Movement (inch/year) long-term[ii] | short-term[iii] |current[iv]	Time to Reach Allowable Displacement (years) long-term[ii] | short-term[iii] |current[iv]
Akron	4.17	0.006 | 0.077| 0.020	756 | 54| 211
Melde	4.13	0.003 | 0.023| 0.010	1365 | 181| 407
Breen	1.50	0.001 | 0.006| 0.008	2152 | 232| 197
Hockley[i]	1.25	0.014 | 0.036| 0.014	86 | 35| 90
McCarty	0.95	0.009 | 0.030| 0.020	106 | 32| 48
Negyev	2.65	0.001 | 0.044| 0.022	2485 | 60| 122
Oates	2.65	0.003 | 0.017| 0.016	1006 | 158| 168

[i]In 2019, Magellan performed maintenance activities to relieve stress on the pipeline near the Hockley fault.

[ii]Average of movement over the monitoring period.

[iii]Average based on the last two years.

[iv]Based solely on the last recorded fault movement.

Calculations based on the long-term historical rate of movement indicate that all the faults, except Hockley, continue to move slowly and the pipeline crossing those faults have more than 100 years to reach the allowable displacement.

In some cases, the long-term historical rates appear to be non-conservative estimates of time to potential failure. Hence, Kiefner also computed a short-term assessment by linear trend lines fit to the last two-years of data. This reveals that Akron, Hockley, McCarty, and Negyev faults have been more active lately. At Akron fault, significant movement is observed in the last few years with a high short-term rate of movement. Kiefner recommends a more frequent monitoring compared to the original semi-annual frequency at this fault. It should be noted that these recent activities are basically large oscillations around a mean value resulting in self-equilibrating for the past couple of years. In addition, depending on the age of the pipeline segments crossing the Akron fault, if the same rate of movement continues in 2020, Kiefner recommends conducting a more detailed analysis such as utilizing a finite element method for a more robust predictive capability of if/when/where fault movements become critical.

At Hockley fault, following the December 2018 fault monitoring, Magellan initiated maintenance activities to relieve strain on the pipeline near the Hockley benchmark. In McCarty and Negyev, based on the short-term trend, time to reach allowable displacement is reported to be 32 and 60 years, respectively. Given the pipeline crossing these two faults is relatively new, installed in 2012, accumulative movement is far from approaching the acceptance limits; nevertheless, Kiefner recommends close monitoring of these two faults.

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 19. Actual measurements over the past 15.5 years show rates that are less than an order of magnitude of 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.

2.3.4 Waterway Inspection

Since 2015, Magellan conducts annual waterway inspections to survey the depth-of-cover (DOC) of the pipeline at the five water crossings (Colorado River, Pin Oak Creek, Cypress Creek, Greens Bayou, and Brazos River). The pipeline has been buried deep below the crossing at the Brazos River and Colorado River via horizontal direction drilling (HDD). The 2017 inspection report by ONYX indicated that no exposed pipelines at the crossings, with all locations maintaining minimum DOC. The surveys found shallow cover at the Pin Oak Creek Crossing and an exposed segment at the Cypress Creek Crossing.

Onyx Services performed a DOC survey of the East Houston to El Paso 18" (Longhorn) Line that crosses Pin Oak Creek in Bastrop County, Texas on March 30, 2019, including both waterway banks. The survey found the pipeline is exposed off the west bank for 5 feet. The pipeline has a maximum DOC of 4 feet at the East banks water's edge. The east and west banks show moderate signs of erosion including Upstream and Downstream of the centerline. Magellan should continue to perform waterway inspections at the current frequency to monitor the conditions and perform further remediation at Pin Oak Creek if necessary.

Flood monitoring should be conducted periodically to identify existing and potential problem areas, especially for lack of coating at flooded regions. Flood monitoring was not conducted in 2019 and should be undertaken in the future to make sure the pipeline integrity is not compromised. Weather events like tropical depression and hurricanes may aggravate the flooding, and additional monitoring should be done after such major weather events to ensure the pipeline's integrity is not jeopardized.

2.4 Third-Party Damage

TPD refers to the accidental or intentional damage by a third party – that is, not the pipeline operator or subcontractor – that causes an immediate failure or introduces a weakness (such as a dent or gouge) in the pipe. 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 DOC over the pipeline. In all cases, different threats could exist at different locations along the pipeline.

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

Kiefner received a complete log of aerial and ground surveillance data for 2019. 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 (MP 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.

Based on a review of the TPD data and a review of the 2019 Third-Party Damage Annual Assessment, Kiefner concluded:

- There were no physical hits to the pipeline.
- There were no ROW near-misses.
- There were four one-call violations.
- There was an increase of approximately 16% in aerial patrol observations.
- There were 56 ROW encroachments recorded, one of which was unauthorized.
- One-call frequency increased by 6% and the number of tickets sent to Field Operations for clearing/locating increased by 16% from 2018 to 2019.

2.4.1 ROW Surveillance

Total possible surveillance mileage includes the 694-mile mainline 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 from Galena Park to Pecos River (Segment 301) must be inspected every 2½ days with a 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, and at least 52 times per year. Daily patrols are also required over the Edwards Aquifer Recharge Zone (MP 170.5 to 173.3) with one patrol per week to be a ground-level patrol. To meet the minimum ROW surveillance mileage Magellan would need to perform 65,636 miles of aerial patrol for the Galena Park to MP 528 segment and 13,676 miles of aerial patrol from MP 528 to 694. For ground patrol, Magellan would need to perform a minimum of 145.6 miles in the Edwards Aquifer area.

To meet this requirement through aerial patrols, the pipeline ROW was flown over daily from the Galena Park to Pecos River (MP 528) segment (weather permitting) as well as weekly from the Pecos River (MP 528) to the El Paso Terminal (MP 694) segment (weather permitting). Regular ground patrols were made in the Edwards Aquifer Recharge Zone (MP 170.5 to 173.3), weather permitting. The 2019 cumulative miles of patrols for these three areas are listed in Table 20 by month.

Table 20. Cumulative Miles of Patrols

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Tiers II & III: Aerial Patrol (every 2.5 days, not to exceed 72 hours)													
301: Galena Park to MP 528	10,687	6,867	10,264	12,431	9,838	14,174	16,171	15,483	14,154	12,692	9,958	13,405	**146,124**
Tier I: Aerial Patrol (once/week, not to exceed 12 days)													
303: MP 528 to 694	1,315	789	1,315	1,315	1,052	1,052	1,315	1,052	1,315	1,052	1,052	1,315	**13,939**
Ground Patrol (once/week)													
Edwards Aquifer: MP 170.5 to 173.3	11	11	14	36	44	55	44	55	55	44	44	77	**490**

Magellan was able to meet the Longhorn commitment to inspect Tier I areas from the Pecos River (MP 528) to the El Paso Terminal (MP 694), including the El Paso Laterals, at least once a week. The Annual Third-Party Damage Prevention Program reported 56 ROW encroachments; one of which was unauthorized.

2.4.2 One-Call Ticket Analysis

In 2019 there were 23,861 one-call tickets; of which 51.5% of the required "field locates" were potential ROW encroachments. There were four one-call violations during the 2019 year. One of which involved a landowner installing a fence without placing a one call. The other three violations involved a guard rail post, an electric line, and a communication cable. No contact with the pipeline occurred.

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.

Magellan is effectively screening the one-calls to separate, based on 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 14834 (62%) of the one-call tickets. Travis County (Austin) accounted for 2434 (10%) of the one-call tickets. Thus, 72% 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 1255 tickets (5%).

2.4.3 Inspection Activities

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[18] and Crane Station be carried out within three years of a previous inspection. EGP inspection tools were run in 2019 on Satsuma to E. Houston, Warda to Buckhorn, and Crane to Texon. For specific inspection dates to fulfill the requirement for each of the 12 intervals spanning the Existing Pipeline from Crane to East Houston see Section 5, Table 33 on Integration of Intervention Requirements.

2.4.4 Public Awareness

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. The Magellan website is a communication tool used to inform the public about pipeline safety, damage prevention, and mitigation measures. There were a total of 3,667 website visits in 2019 with an average view time of 59 seconds.

2.5 Stress-Corrosion Cracking (SCC)

SCC is a form of environmental attack on 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 since SCC has been an unexpected problem for some pipelines. In the 69 years the existing pipeline has been in operation, there have been no SCC failures and no SCC has been discovered at any location on the pipeline.

In accordance with the LMC 19(a) and the 2003 Office of Pipeline Safety (OPS) Advisory Bulletin ADM-05-03 "Stress-Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines," Longhorn was required to inspect for SCC, for the first three years (2005-2007) 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 2019 Magellan performed ILI investigation digs and during each dig, the exposed pipe surface was checked for SCC using magnetic particle testing. Magnetic particle inspection is conducted on the full pipe circumference between coating cuts. Coating is typically removed a couple of feet to either side of the ILI target anomaly. If there are multiple ILI target anomalies within a single joint, the coating is typically removed for the entire distance between anomaly targets (unless the two target anomalies are at extreme opposite ends of the joint). 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.

2.6 Threats to Facilities

This section of the ORA addresses the operational reliability of facilities other than line pipe, including pump stations, terminals, and associated mechanical components. Magellan monitors

[18] Valve J-1 is no longer in service. ILI assessments for TPD are currently performed from E. Houston to Crane.

the integrity of these facilities through scheduled maintenance and inspection activities prescribed by the LPSIP. The LPSIP Mechanical Integrity Program focuses on maintaining the integrity of all equipment within the Longhorn system (e.g., station pumps, tanks, valves, and control systems). The program includes the following activities:

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

The preventive maintenance program is implemented through the use of a software database system called Enviance/Compliance Management System (CMS). The software system establishes an 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.

A Facility Risk Management Program is in place to manage the risks at above ground facilities. The LMP requires that all changes on the Longhorn system be evaluated using an appropriate PHA methodology and that the change be assessed to ensure that the appropriate risk mitigation levels on the system are maintained. PHAs are also conducted on a 5-year interval to evaluate and control the hazards associated with the Longhorn facilities. Eight PHAs were completed in 2019. Here, eight PHAs were completed and reviewed by Kiefner as a part of the ORA. The PHA techniques chosen were the Hazard and Operability Study and What-if Analysis. The HAZOP and What-if analysis process and requirements are well defined in 29 CFR 1910.119(e)(2)(i) Et. Seq. Kiefner did not participate in the PHA process; therefore, our review consisted of a document review of the final deliverables. The PHA's that were reviewed indicated that all were well attended by an expected level of operational and PHA leaders with appropriate training, skill, and knowledge of the system. It appears that the nodes identified were appropriate for the process and systems; and the discussion of the standard process upsets was thoroughly reviewed and considered. For the review of upset process hazard conditions, an appropriate risk matrix was developed and risks were well prioritized into categories consistent with a system of this type. Additionally, for each hazard a review of the appropriate controls applicable to their hazards and their interrelationships appears to have been reviewed and addressed as well as the consequences thereof.

Facility inspections addressing items related to safety, security, and environmental compliance are conducted on a regular basis. 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. 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. Kiefner received 14 facility inspection reports as listed in Table 21.

Table 21. Facility Inspections received in 2019

Facility	Inspection Date
Bastrop	7/5/19
Buckhorn	10/29/19
Cartman	8/29/19
Cedar Valley	5/10/19
Cedar Valley	5/10/19
Eckert	5/24/19
James River	8/29/19
Kimble	8/29/19
Satsuma	10/29/19
Warda	7/5/19
Barnhart Station	10/29/19
Barnhart Terminal	10/28/19
Crane Terminal	10/28/19
Texon Station	10/29/19

Magellan conducted three incident investigations on the Longhorn Pipeline in 2019. Two of the three Longhorn System incidents were categorized as equipment failures: one minor and one significant. The minor incident was described as a primary network switch failure at the Crane Terminal and cost approximately $2,500. The significant incident was reported as a power glitch that shut down all power to the facility at the El Paso Terminal after lightning was spotted in the area. Power was restored within seconds; however, smoke was seen coming from the facility and police and fire crews were notified. Although there was no exact cost specified for the property damage from the incident it is estimated between $25,000 and $500,000. Neither incident was DOT reportable. The third incident was a one-call violation. Corrective actions were implemented in accordance with Magellan's incident investigation report which was provided to PHMSA.

From the standpoint of facility data acquired for 2019, one can conclude that the facilities were well maintained and had no adverse impact on public safety. Kiefner recommends that Magellan continue its detailed documentation of incidents, its facility integrity processes, and its reporting of the facility maintenance program.

3 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.

3.1 Longhorn Corrosion Management Plan

The LMP entails an extensive Corrosion Management Plan (CMP) to control the extent of corrosion. The 2019 CMP considered the following items: Probability of Exceedance (POE), review of internal corrosion coupons, review of field dig reports (covered under Section 2.2.1

Maintenance Reports and In-Ditch Evaluations), review of the CP system for buried pipelines, review of the atmospheric inspection for above grade appurtenances, and review of the tank inspections.

3.1.1 Probability of Exceedance Analysis

POE calculations were performed on the five pipeline segments assessed in 2019 or had reports received in 2019. POE calculations were performed using ILI tool information (TDW MFL or GMFL and BHGE MF4) and utilizing a CGR of 5 mpy for external ML and 1 mpy for internal ML over a 5-year range. Twenty-one ML features were found to meet POE dig requirements of $10E^{-5}$; see Table 22. No ML feature met the POE dig requirement of $10E^{-5}$ on E. Houston to Speed Jct and El Paso to Strauss.

Table 22. Metal Loss with a POE Value Greater than $10E^{-5}$

Pipeline Segment	Absolute Distance (feet)	Predicted Depth (% WT)	Predicted Length (inch)	POE	POE Type
Crane to Texon	117491.1	27	3.50	1.06E-05	Pressure
Warda to Buckhorn	93619.2	45	6.22	6.23E-02	Pressure
Warda to Buckhorn	97464.4	36	14.13	5.23E-02	Pressure
Warda to Buckhorn	93642.1	35	14.80	3.77E-02	Pressure
Warda to Buckhorn	93538.9	37	9.76	2.47E-02	Pressure
Warda to Buckhorn	93741.7	32	11.89	4.77E-03	Pressure
Warda to Buckhorn	70706.9	37	6.77	3.11E-03	Pressure
Warda to Buckhorn	151537.6	29	12.44	1.12E-03	Pressure
Warda to Buckhorn	156486.1	47	3.23	1.02E-03	Depth
Warda to Buckhorn	93553.9	46	0.67	6.56E-04	Pressure
Warda to Buckhorn	93551.4	26	17.91	5.50E-04	Pressure
Warda to Buckhorn	151768.6	31	8.31	5.24E-04	Pressure
Warda to Buckhorn	93580.7	29	8.35	1.79E-04	Pressure
Warda to Buckhorn	93640.9	27	9.57	1.20E-04	Pressure
Warda to Buckhorn	37634.6	34	9.57	1.12E-04	Pressure
Satsuma to East Houston*	96911.3	34	10.83	3.11E-03	Pressure
Satsuma to East Houston	47995.0	48	0.20	1.07E-03	Depth
Satsuma to East Houston	34330.2	46	0.28	4.40E-04	Depth
Satsuma to East Houston*	142155.9	45	0.32	2.76E-04	Depth
Satsuma to East Houston*	143247.3	44	1.14	1.70E-04	Depth
Satsuma to East Houston*	142155.7	43	0.32	1.04E-04	Depth

* Feature has been previously repaired.

3.1.2 Internal Corrosion Coupons

Internal corrosion is monitored using internal corrosion coupons placed along the Longhorn system including the Longhorn Lateral lines. The LMP is specific that the internal corrosion coupons located at the El Paso terminal and Odessa Station are supposed to be evaluated three times per year with a not-to-exceed of 4.5 months (135 days) between surveys. For 2019 there are 56 coupons for the crude line segment and 17 coupons for the refined line segment for a total of 73 internal corrosion coupons. The inserted and removed date of coupons were scattered from 9/6/2018 to 12/16/2019. The coupon testing days range from 64 to 190 days. Four of the 73 coupons were damaged during the testing and could not be processed. Two of the 73 coupons were not returned as of 1/17/2020. According to the coupon testing results, no corrosion to the maximum of 0.62 mpy corrosion rate was observed on the internal corrosion coupons for the Longhorn system. Monitoring should continue to identify future potential changes in the pipelines. Internal corrosion coupon results are shown in Table 23 for the refined line and Table 24 for the crude line.

Table 23. Internal Corrosion Coupon Results for Refined Line

Pipe OD (inch)	Location	Line Designation (Line ID)	Coupon Number	Inserted	Removed	Exposure (days)	Rate (mpy)	Comments
8	Crane	8” Odessa to Crane (6648)	U9931	12/12/18	4/15/19	124	N/A	*
8	Crane	8” Odessa to Crane (6648)	V2292	4/15/19	8/28/19	135	0.02	
8	Crane	8” Odessa to Crane (6648)	V2450	8/28/19	12/13/19	107	0.01	
18	El Paso	18” Mainline (6645)	V4339	12/12/18	4/12/19	121	0.01	
18	El Paso	18” Mainline (6645)	V4342	4/12/19	8/16/19	126	0.00	
18	El Paso	18” Mainline (6645)	V4341	8/16/19	12/13/19	119	0.00	
8	El Paso	KM 8" (6649)	AA1791	9/6/18	3/18/19	193	0.00	
8	El Paso	KM 8" (6649)	G9649	3/18/19	9/14/19	180	0.00	
8	El Paso	Plains-8" (6650)	V4340	12/12/18	4/12/19	121	0.01	
8	El Paso	Plains-8" (6650)	V4343	4/12/19	8/16/19	126	0.06	
8	El Paso	Plains-8" (6650)	V4344	8/16/19	12/13/19	119	0.01	
12	El Paso	KM 12" (6651)	AA1681	9/6/18	3/15/19	190	0.01	
12	El Paso	KM 12" (6651)	G9993	3/15/19	9/14/19	183	0.00	
8	El Paso	KM 8" flush (6652)	AA1682	9/6/18	3/15/19	190	0.01	
8	El Paso	KM 8" flush (6652)	G9994	3/15/19	9/14/19	183	0.00	
8	Santa Teresa	Strauss 8" (6653)	AA1773	9/6/18	3/15/19	190	0.01	
8	Santa Teresa	Strauss 8" (6653)	G9625	3/15/19	9/14/19	183	0.00	

*Damaged, coupon could not be processed.

Table 24. Internal Corrosion Coupon Results for Crude Line (pg. 1 of 2)

Pipe OD (inch)	Location	Line Designation (Line ID)	Coupon Number	Inserted	Removed	Exposure (days)	Rate (mpy)	Comments
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	H0094	12/12/18	3/27/19	105	0.00	
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	AA2130	3/27/19	8/16/19	142	0.01	
20	Speed Jct	Speed Jct Manifold from E Houston (6643)	H0242	8/10/19	12/12/19	124	0.00	
20	E. Houston	East Houston ML (6645)	U9933	1/4/19	4/15/19	101	N/A	*
20	E. Houston	East Houston ML (6645)	V2294	4/15/19	8/20/19	127	N/A	*
20	E. Houston	East Houston ML (6645)	V2446	8/20/19	12/15/19	117	0.00	
18	Satsuma	Satsuma Station ML (6645)	H0097	12/14/18	4/15/19	122	0.02	
18	Satsuma	Satsuma Station ML (6645)	H9529	4/15/19	8/16/19	123	0.03	
18	Satsuma	Satsuma Station ML (6645)	H0240	8/16/19	12/6/19	112	0.00	
18	Satsuma	Satsuma Station ML (6645)	AA2133	-	-	-	N/A	**
18	Cedar Valley	Cedar Valley Station ML (6645)	H0096	12/14/18	3/26/19	102	0.04	
18	Cedar Valley	Cedar Valley Station ML (6645)	AA2132	3/26/19	8/19/19	146	0.01	
18	Cedar Valley	Cedar Valley Station ML (6645)	H0245	8/19/19	12/5/19	108	0.00	
18	Cartman	Cartman Station ML (6645)	H0095	1/22/19	3/27/19	64	0.04	
18	Cartman	Cartman Station ML (6645)	AA2131	3/27/19	9/18/19	175	0.01	
18	Cartman	Cartman Station ML (6645)	H0244	9/19/19	12/5/19	77	0.00	
24	Crane	24” Tank Manifold (6645)	U9930	1/22/19	4/15/19	83	N/A	*
24	Crane	24” Tank Manifold (6645)	V2291	4/15/19	8/28/19	135	0.03	
24	Crane	24” Tank Manifold (6645)	V2451	8/28/19	12/13/19	107	0.00	
16	Crane	16” Plains WTI – Delivery (6645)	U9932	12/12/18	4/15/19	124	0.02	
16	Crane	16” Plains WTI – Delivery (6645)	V2293	4/15/19	8/28/19	135	0.03	
16	Crane	16” Plains WTI – Delivery (6645)	V2447	8/28/19	12/16/19	110	0.00	

*Damaged, coupon could not be processed.
**Not returned as of 1/17/2020.

Table 24 (continued). Internal Corrosion Coupon Results for Crude Line (pg. 2 of 2)

Pipe OD (inch)	Location	Line Designation (Line ID)	Coupon Number	Inserted	Removed	Exposure (days)	Rate (mpy)	Comments
16	Crane	16" Plains WTS – Delivery (6645)	U9935	12/12/18	4/15/19	124	0.00	
16	Crane	16" Plains WTS – Delivery (6645)	V2295	4/15/19	8/28/19	135	0.00	
16	Crane	16" Plains WTS – Delivery (6645)	V2444	8/28/19	12/16/19	110	0.00	
10	Crane	10" Truck Offload WTI (6645)	U9939	12/12/18	4/15/19	124	0.12	
10	Crane	10" Truck Offload WTI (6645)	V2299	4/15/19	8/28/19	135	0.42	
10	Crane	10" Truck Offload WTI (6645)	V2337	8/28/19	12/13/19	107	0.33	
10	Crane	10" Truck Offload WTI (6645)	H0092	-	-	-	N/A	**
10	Crane	10" Truck Offload WTS (6645)	U9940	12/12/18	4/15/19	124	0.00	
10	Crane	10" Truck Offload WTS (6645)	V2300	4/15/19	8/28/19	135	0.03	
10	Crane	10" Truck Offload WTS (6645)	V2315	8/28/19	12/13/19	107	0.02	
16	Crane	16" Medallion – Delivery (6645)	U9938	12/12/18	4/15/19	124	0.03	
16	Crane	16" Medallion – Delivery (6645)	V2298	4/15/19	8/28/19	135	0.02	
16	Crane	16" Medallion – Delivery (6645)	V2331	8/28/19	12/16/19	110	0.00	
16	Crane	16" Oryx – Delivery (6645)	U9937	12/12/18	4/15/19	124	0.01	
16	Crane	16" Oryx – Delivery (6645)	V2297	4/15/19	8/28/19	135	0.02	
16	Crane	16" Oryx – Delivery (6645)	V2325	8/28/19	12/16/19	110	0.00	
12	Crane	Centurion – Delivery (6645)	U9936	12/12/18	4/15/19	124	0.00	
12	Crane	Centurion – Delivery (6645)	V2296	4/15/19	8/28/19	135	0.00	
12	Crane	Centurion – Delivery (6645)	V2436	8/28/19	12/16/19	110	0.00	
16	Crane	16" Advantage – Delivery (6645)	U9929	12/12/18	4/15/19	124	0.00	
16	Crane	16" Advantage – Delivery (6645)	V2290	4/15/19	8/28/19	135	0.02	
16	Crane	16" Advantage – Delivery (6645)	V2453	8/28/19	12/16/19	110	0.00	
16	Ozona	16" JP Energy – Delivery (6645)	H0100	12/14/18	4/10/19	117	0.09	
16	Ozona	16" JP Energy – Delivery (6645)	AA2136	4/10/19	8/19/19	131	0.06	
16	Ozona	16" JP Energy – Delivery (6645)	G9469	8/19/19	12/12/19	115	0.00	
18	Ozona	BH 18" to LH 18" (6645)	H0099	12/14/18	4/10/19	117	0.07	
18	Ozona	BH 18" to LH 18" (6645)	AA2135	4/10/19	8/19/19	131	0.03	
18	Ozona	BH 18" to LH 18" (6645)	G9467	8/19/19	12/12/19	115	0.00	
20	Ozona	20" Downstream of Strainers	H0098	12/14/18	4/10/19	117	0.07	
20	Ozona	20" Downstream of Strainers	AA2134	4/10/19	8/19/19	131	0.03	
20	Ozona	20" Downstream of Strainers	G9466	8/19/19	12/12/19	115	0.00	
24	Ozona	24" Downstream Tks 100 & 101	H101	12/14/18	4/10/19	117	0.04	
24	Ozona	24" Downstream Tks 100 & 101	AA2137	4/10/19	8/19/19	131	0.62	
24	Ozona	24" Downstream Tks 100 & 101	G9470	8/19/19	12/12/19	115	0.19	

**Not returned as of 1/17/2020.

3.1.3 Cathodic Protection System

To evaluate the effectiveness of the CP systems that are currently in place for the Longhorn pipeline system, the rectifier inspections and maintenance, test point surveys, and close interval surveys were reviewed. The rectifiers were inspected monthly in 2019, including output voltage and current. A close interval survey (CIS) was performed in November 2019 and was received by Magellan in February 2020 for the pipeline ROW from stationing 395+56 to 26340+35. The CIS data will be analyzed and summarized in the 2020 Longhorn ORA report. Semi-annual surveys are being conducted on Tier II and Tier III areas per LMC 32.

3.1.4 AC Potential Survey

The pipe to soil AC voltage survey was conducted when the CIS was performed in November 2019 for the pipeline ROW from stationing 395+56 to 26340+35. The AC voltage survey will be analyzed and summarized in the 2020 Longhorn ORA report.

3.1.5 Atmospheric Inspections

The condition of above-grade appurtenances is monitored following annual atmospheric inspection, including station piping, tanks, valve settings, and exposed piping. Table 25 lists the locations of concern in the Longhorn Pipeline System where corresponding repairs are needed.

Table 25. Atmospheric Inspection Summary (pg. 1 of 2)

Atmospheric Facility Type	Inspection Date	Milepost	Inspection Remarks
Galena Park Station	10/04/19	1.000	Spot coat riser at KM connection, paint stainer valve, spot coat prover, spot coat trap
Satsuma Station – Receiver/Incoming & drain line	4/18/19	1.000	Lower two 18” supports, clean and reseal FRP/20 dime spots on pig trap
Satsuma Station-N. Pump suction/discharge	4/18/19	6.000	Recoat 20ft of 16"
Satsuma Station-S. Pump suction/discharge	4/18/19	7.000	Recoat 15ft of 16" on discharge side
24" WTS at Customer Lines to Manifold (under rack)	6/04/19	15.000	Flange and bolts need painted.
#1 Refined Pump Suction	6/04/19	44.000	Flange and bolts need painted
Crude Inhibitor Tank 901136 (interface on 1" line)	12/17/19	49.000	Repaint 1" piping inside containment
Suction Header North of Crude Manifold From MOV 5 to MOV119/120	12/17/19	75.000	Clean up transition at MOV 119
30" WTI From Crude Manifold to Transition Between Tank 51 & 53	12/18/19	99.000	Recoat transition
Tank 51	12/17/19	102.000	Touch-up spots at top of stairs (shell/hatch/roof)
Tank 53	6/04/19	125.000	Roof and bottom extension 3. Shell light surface rust on south east side to southwest side of tank.
30" Tank Lines From Vault Transitions to Manifold	12/18/19	142.000	Paint spools on north side of manifold
WTS Crude Offloading Manifold @ North Fence	12/18/19	221.000	Paint 4" valves and flanges
Tank 3 & 4 Pump - Transitions to Piping	12/18/19	228.000	Paint spool
Eckert Station-East Pump suction/discharge	6/19/19	3.000	Blast and recoat flange to interface suction/discharge
Eckert Station-Sump piping	6/19/19	4.500	Blast and recoat 1" and 2" sump lines and 30' of vertical 2" sump vent
Buckhorn Station-Receiver/Incoming and drain line WSD	6/12/19	1.000	Blast and recoat 50' of 4" drain line, (3) 4" valves
Buckhorn Station- 6" and 8" bypass lines along N. fence	6/12/19	1.500	Blast and recoat 8" 20' WSD/20' ESD, remove (2) 8” U-straps and recoat under
Buckhorn Station-Launcher/Outgoing and drain line ESD	6/12/19	2.000	Blast and recoat 50' of 4" drain line, (3) 4" valves
Buckhorn Station-Central Manifold	6/12/19	3.000	See 2018 Maintenance item, general corrosion at 4 unpainted areas at saddle supports
Buckhorn Station-East Pump suction/discharge	6/12/19	4.000	Last and recoat suction and discharge, flange to flange, 20 ft of 16”
Buckhorn Station-West Pump suction/discharge	6/12/19	5.000	Blast and recoat 10ft of 16" discharge side only
Propane and Sump Line at Sample Building	12/17/19	1.000	Propane transition needs recoated
Receiving Tank 11 Piping – Including 4” Sump Line	12/17/19	53.000	Recoat several valves/flanges near pump
Receiving Tank 12 Piping	12/17/19	55.000	Recoat several valves/flanges near pump
Receiving Tank 22 Piping	12/17/19	61.000	Repaint several flanges south of pump
GS5 Mesa Road Valve site	5/03/19	11.9836	Paint Mainline valve

Table 25 (continued). Atmospheric Inspection Summary (pg. 2 of 2)

Atmospheric Facility Type	Inspection Date	Milepost	Inspection Remarks
East of 1320	5/28/19	210.050	Underwater
East of 1320	10/29/19	210.050	Silted in
Exposed Pipe	5/28/19	228.8036	Silted in
Exposed Pipe	10/29/19	228.8036	Silted in
Pasture Exposure	5/10/19	232.070	Silted in
Pasture Exposure	10/29/19	232.070	Silted in
Expansion Loop, 30' Exposed	12/04/19	28.7259	Various rust spots on line, no corrosion
Galena Park Station	10/04/19	0.0000	Spot coat trap and interface
Hartmen WSD	10/04/19	25.6179	Touch-up

3.1.6 Tank Inspection

A total of 14 tanks were inspected and their inspection types are listed in Table 26. All 14 tanks were inspected externally. The external inspection reports for Tanks L1 to L6 in Crane and Tanks 2, 4, 9, 10, 11, and 19 in El Paso show that no problems requiring immediate action were found on foundation, shell, piping and appurtenances, fixed roof, floating roof, and access structure. The external inspection report for Tank 3 shows that the level gauge was not working at the time of inspection. The level gauge should be serviced to ensure proper operation. The external inspection report for Tank 17 states that the column well and combination gauge pole/ ladder well seal had a gap and was not bolted down on 3/5/2019. A 10 year in-service inspection was performed on 3/15/2019 and repairs were made.

Table 26. Tank Inspection Summary

Tank #	Tank location	Product	Inspection type	Inspection date	Comments
L1	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
L2	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
L3	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
L4	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
L5	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
L6	Crane	Crude Oil	External API-653	07-10-2019	No items of concern noted
2	El Paso	Gasoline	External API-653	03-06-2019	No items of concern noted
3	El Paso	Gasoline	External API-653	03-06-2019	The level gauge read out at the tank did not appear to be operating properly at the time of inspection
4	El Paso	Diesel	External API-653	03-06-2019	No items of concern noted
9	El Paso	Transmix	External API-653	03-06-2019	No items of concern noted
10	El Paso	Gasoline	External API-653	03-05-2019	No items of concern noted
11	El Paso	Diesel	External API-653	03-05-2019	No items of concern noted
17	El Paso	Fuel oil	External API-653	03-05-2019	One minor seal issue was found. A 10 year in-service inspection was performed on 3/15/2019 and repairs were made.
19	El Paso	Relief	External API-653	03-05-2019	No items of concern noted

3.2 In-Line Inspection and Rehabilitation Program

The 2019 MFL assessments for East Houston to Speed Jct and El Paso to Strauss reported similar magnitudes of ML features when compared with the previous MFL assessments completed in 2014. The 2019 MFL assessment on Satsuma to East Houston reported a similar magnitude of ML features compared with the previous MFL assessment completed in 2014 but did note an increase in ML features in the 20-40% WT ML depth range. A run-to-run comparison was performed between the current and previous MFL assessments. The comparison indicated areas with possible internal/external feature call discrepancy between the current and previous MFL assessments for East Houston to Speed Jct and Satsuma to East Houston; see Section 2.2 Corrosion for further details. The 2019 UCD assessments reported more crack-like seam features than seam features reported from the previous SMFL or TFI assessments completed in 2014/2015. The severity of the 2019 UCD features was on the same scale as the previous assessments; 2019 depths ranged from 10-49% WT for the Crane to Texon segment and 10-42% WT for the Satsuma to East Houston segment. The 2014 depths ranged from 10-51% WT for Crane to Texon and 10-47% WT for Satsuma to East Houston.

The 2019 EGP assessments reported 227 ID reductions with 73 located in HCAs. None of the features reported required a repair based on regulatory requirements; however, 14 features have been noted as previously repaired with 11 of those located in HCAs.

3.3 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
- 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 a 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 mitigation 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 2019. The results show that none of the pipeline segments exceeded the risk threshold; therefore, no additional mitigation measures were required or recommended.

3.4 Damage Prevention Program

Prevention activities include ROW surveillance, One-Call System, and public-awareness activities that continued to be successful in 2019. The Longhorn Damage 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 met the frequencies set forth in the LMP with a few exceptions due to severe weather and poor visibility in February, March, May, and October of 2019.

3.5 Encroachment Procedures

Encroachments are entries to the pipeline 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 unannounced or unauthorized ROW encroachments. Magellan conducted three incident investigations as part of the LPSIP, one of which was associated with Third-Party Unauthorized Encroachment

There were a total of 56 encroachments during 2019, one of which was unauthorized and 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.

3.6 Incident Investigation Program

Magellan is performing incident investigations on all Department of Transportation (DOT)-reportable[19] incidents as well as smaller non-reportable incidents and near-miss events.

During 2019, there were three Longhorn System incidents: one minor, one significant, and one one-call violation. Further details on the three incidents can be found in Section 2.6 Threats to Facilities. Neither the minor or significant incidents were DOT reportable. Corrective actions were implemented in accordance with Magellan's incident investigation report which was provided by PHMSA.

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.

[19] DOT-Reportable Requirement**.** 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.

3.7 Depth-of-Cover Program

The most recent DOC survey was completed in 2017 on the crude section of the Longhorn pipeline from Crane to East Houston. All areas of concern were analyzed by Asset Integrity. All sites will be actively managed under the Outside Forces Damage Prevention Program in accordance with the LPSIP. No third-party damage was found. 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.

3.8 Fatigue Analysis and Monitoring Program

The 2019 fatigue analysis incorporated results from the 2014 SMFL and 2015 TFI tool runs as well as the recent UCD tool inspections of the Crane to Texon and Satsuma to East Houston segments. The reassessment interval was calculated in an effort to allow Magellan to effectively monitor the potential for fatigue degradation from pressure-cycle-induced crack growth. Based on the threshold of detection for the 2014 SMFL and 2015 TFI tool runs, the shortest time to reassessment is calculated to be 7.4 years from August 2015 leading to a reassessment date year of 2022 for the Texon to Barnhart segment. The analysis of indications reported from the recent UCD inspections resulted in a reassessment interval of 11.4 years for an indication in the Crane to Texon segment of the line leading to a reassessment year of 2030. The analysis for this program is covered under Section 2.1 Pressure-Cycle-Induced Fatigue of this report.

3.9 Risk Analysis Program

The objective of Magellan's Risk Analysis 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 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 the identification of preventive and mitigative measures to protect areas along the pipeline. Magellan is committed to maintaining at or below $1E^{-4}$ (0.0001) failures (PHMSA reportable incidents) per mile-year at all locations along the non-facilities portions of the pipeline.

Magellan's risk model is updated periodically as new information becomes available. The pipeline risk model was updated with information from operations in 2019 and executed. Results show no areas along the pipeline with POF greater than $1E^{-4}$ failures and as such supports the effectiveness of Magellan's existing Integrity Management Program. PHAs are performed on all new facilities, when changes occur in existing facilities, and at 5-year intervals to evaluate and control potential hazards.

3.10 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. There were three Longhorn system incidents in 2019, two of which involved equipment failures: one minor incident at the Crane Terminal and one significant incident at the El Paso Terminal. The third incident was a one-call violation. Further details on these incidents can be found in Section 2.6 Threats to Facilities. These incidents have been formally documented and investigated and corrective actions were implemented in accordance with Magellan's incident investigation report.

3.11 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 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.

3.12 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; and
- 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 minimum required mileage for both aerial surveillance and ground patrol. In addition, ROW markers and signs were repaired or replaced where necessary (Table 27) and public-awareness meetings were held (Table 28). From the standpoint of ML deterioration measures, 21 ML features met POE dig requirements from the 2019 ILI runs. In terms of failure measures, there was no DOT-reportable incident and no physical hits to the pipeline.

Table 27. Markers Repaired or Replaced[20]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
# Repaired or Replaced	0	2	17	10	7	2	40	11	1	0	0	3	93

[20] Mitigation Plan Scorecard 2019.

Table 28. Educational and Outreach Meetings

EVENT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Emergency Responder / Excavator Meetings	14	12	11	11	11	11	11	11	11	25	30	30	16	16	24
School Program - Houston	2	2	3	4		6	5	6	1	3	4	4	5	5	5
School Program - Austin	3	2	7	3	4	3	4	5	5	2	2	2	3	2	3
Texas Statewide School Pipeline Safety Outreach													16	3	30
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							*	12	12
TOTAL	28	18	25	21	17	22	20	22	17	30	36	36	24	38	75

NOTE: Public meetings were tallied for the years 2005-2019 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.
- Texas Statewide: Texas School Safety Conference
- 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.

*Refer to the 2019 TPD Annual Assessment for details.

4 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 ensures 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 (listed below). The 2019 status of each of these measures is evaluated in Section 4.1 through 4.3.

- 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

4.1 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; Table 29 provides a summary of the LPSIP Activity Measures from 2005 through 2019. The activity 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>. The minimum ROW surveillance aerial patrol mileage needed to meet this requirement is 65,636 miles for Galena Park to MP 528 and 13,676 miles for MP 528 to 694. For ground patrol 145.6 miles is needed for the Edwards

Aquifer area. This metric is also compared to the previous 12-month period. Magellan met this commitment in 2019.

- Number of warning or ROW identification signs installed, replaced, or repaired during 12-month period. The metric is compared to previous Magellan performance. This metric is used to measure consistent effort by Magellan to protect the ROW and to prevent TPD. There is no "passing grade", because proper placement and maintenance of signs may lead to fewer signs 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, to prevent 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.
- 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 29. LPSIP Activity Measures

Measure	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Miles of pipelines inspected by aerial and ground survey (79,457.6 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	162,030	152,322	160,553
No. of warning or ROW identification signs installed, replaced, or repaired	979	732	237	536	460	291	76	66	539	266	130	315	194	105	93
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	36	24	24	33

4.2 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 2006 through 2019 is presented in Table 30.

In 2019 there were no immediate conditions as defined by the LPSIP and 49 CFR 195.452. The 2019 results follow a similar trend to recent years (2009-2018) where no immediate conditions had been reported. The monitoring and excavation program should continue to address significant reported anomalies.

Twenty-one ILI reported metal loss features met POE evaluation dig requirements in 2019. 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 30. LPSIP Deterioration Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
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	0	0	0
Number of immediate ILI anomalies, per mile pigged, sorted by tier classification	Tier I	NA	0.0212	0.035	0.006	0	0	0	0	0	0	0	0	0	0	0
	Tier II	NA	0.0208	NA	NA	0	0	0	0	0	0	0.004	0	0	0	0
	Tier III	0.192	NA	0.003	NA	0	0	0	0	0	0	0	0	0	0	0
Total number of anomalies per hydrostatic tests		NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*	NA*
Number of POE Evaluations per mile pigged		1.48	0.54	0.69	0	0.017	0.14	0.035	0.025	0.033	0.017	0.013~	0	0	0.067	0.15

*Hydrostatic tests were performed for pipeline commissioning purposes.
~POE calculations only performed on the MFL assessments; the number of POE evaluations per mile pigged did not include the TFI mileage.

4.3 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 to measure the deterioration of overall system integrity. These measures are listed below in Table 31. Response times, volumes, and costs are for DOT-reportable leaks. Service interruptions reported during 2019 are shown in Table 32.

Table 31. LPSIP Failure Measures

Measure		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Number of leaks (DOT- reportable)		2	0	1	3	0	1	2	0	2	2	0	0	3	1	0
Average response time in hours for a product release.	Tier I	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	Immed.	Immed.	NA	NA	Immed.	Immed.	N/A
	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	NA	NA	N/A
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	Immed.	Immed.	NA	NA	Immed.	NA	N/A
Average product volume released per incident (bbl)	Tier I	5.7	0	5.7	0.4	0	0.4	1.2	NA	0.47	2.74	0	NA	1048	282	0
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA	NA	0
	Tier III	0	0	0	0	0	0	0	NA	4	0	0	NA	28	NA	0
Total product vol. released in the 12-month period (bbl)	Tier I	17	0	5.7	1.3	0	0.4	2.5	NA	0.47	5.48	0	NA	2096	94	0
	Tier II	0	0	0	0	0	0	0	NA	0	0	0	NA	NA	NA	0
	Tier III	0	0	0	0	0	0	0	NA	4 bbls	0	0	NA	28	NA	0
Cleanup cost totals per year		< $100k	$0	< $200k	< $150k	0	< $50	< $50	NA	> $100k	< $25	0	NA	>$528k	$7.2M	<$500K
Cleanup cost per incident		< $35k	NA	< $200k	< $50k	0	< $50	< $25	NA	< $25k < $50k > $100k	< $25	0	NA	$28k $500k No info	$7.2M	<$500K
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	4	5	4
Number of known physical hits (contacts with pipeline) by third-party activities		0	0	0	0	0	0	2	0	0	0	0	0	1	0	0
Number of near-misses to the pipeline by third parties		7	1	7	5	6	2	4	3	2	0	4	0	8	2	1
Number of service interruptions		115	165	155	74	16*	17	9	8	15	15	11	8	13	114	141

Table 32. Service Interruptions per Month for 2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
No./Month	7	7	14	17	15	17	11	10	11	14	10	8	**141**

5 INTEGRATION OF INTERVENTION REQUIREMENTS AND RECOMMENDATIONS

5.1 Integration of Primary Line Pipe Inspection Requirements

Section 11 of the ORAPM 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 an EGP 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 EGP tools must be run at least every three years.

There is overlap in anomaly detection capabilities of the various commercially available ILI tools and considerable variability in vendor availability. 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 using have multiple capabilities.

Table 33 and Table 34 present the most recently completed ILI assessment and note requirement dates for future planned assessments for the crude and refined pipelines, respectively. The required reassessments are specified per the ORAPM. Reassessment requirements for pressure-cycle-fatigue crack growth reassessment intervals were based on the analysis performed in Section 2.1 Pressure-Cycle-Induced Fatigue. Reassessment requirements for corrosion and TPD are based on the most recent inspection date; corrosion inspections are required to be run every five years while TPD is required every three years for the crude line and five years for the refined line. Earth movement, the fifth component for threat integration, is not included in Table 33 because it is currently addressed using surface surveys rather than ILI technology. For a complete listing of all ILI assessments that have occurred on both the crude and refined pipelines refer to the 2017 Longhorn ORA Final Report.

Table 33. Completed ILI Runs and Planned Future ILI's for Longhorn Crude System

		E. Houston to Speed Jct	E. Houston to Satsuma	Satsuma to Buckhorn	Buckhorn to Warda	Warda to Bastrop	Bastrop to Cedar Valley	Cedar Valley to Eckert	Eckert to James River	James River to Kimble County	Kimble County to Cartman	Cartman to Barnhart	Barnhart to Texon	Texon to Crane
	Mileage	**0 to 10.8**	**2.35 to 34.1**	**34.1 to 68.0**	**68.0 to 112.9**	**112.9 to 141.8**	**141.8 to 181.6**	**181.6 to 227.9**	**227.9 to 260.2**	**260.2 to 295.2**	**295.2 to 344.3**	**344.3 to 373.4**	**373.4 to 416.6**	**416.6 to 457.5**
Assessments	**Corrosion**													
	Tool	Multi-Data	Multi-Data											
	Date of Tool Run	2-Oct-14	1-Oct-14											
	Tool			TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run			18-Dec-15	16-Dec15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Tool	GMFL	MFL		MFL									MFL
	Date of Tool Run	28-Aug-19	13-Aug-19		5-Nov-19									16-Oct-18
	Pressure Cycle Induced Fatigue													
	Tool		TFI ‡											
	Date of Tool Run		6-Jul-07											
	Tool			TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI	TFI
	Date of Tool Run			18-Dec-15	16-Dec-15	11-Dec-15	8-Dec-15	4-Dec-15	19-Aug-15	1-Sep-15	29-Aug-15	24-Aug-15	11-Aug-15	17-Jul-15
	Tool		UCD											UCD
	Date of Tool Run		16-Aug-19											19-Oct-18
	Laminations & Hydrogen Blisters													
	Tool		UT	UT	UT	UT	UT	UT	UT	UT	UT	UT	UT	UT
	Date of Tool Run		22-Sep-09	24-Nov-09	24-Nov-09	24-Jan-10	24-Jan-10	20-Feb-10	25-Jun-10	25-Jun-10	25-Jun-10	8-Jul-10	8-Jul-10	8-Jul-10
	Third Party Damage													
	Tool	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.	Def.
	Date of Tool Run	2-Oct-14	14-Sep-17	13-Sep-17	12-Sep-17	4-Jan-18	3-Jan-18	7-Mar-18	6-Mar-18	27-Feb-18	22-Feb-18	20-Feb-18	16-Feb-18	13-Feb-18~
	Tool	Def.	Def.		Def.									Def.
	Date of Tool Run	28-Aug-19	13-Aug-19		5-Nov-19									16-Oct-18~
Next Required Assessment														
	Corrosion	2-Oct-19	13-Aug-24	18-Dec-20	5-Nov-24	11-Dec-20	8-Dec-20	4-Dec-20	19-Aug-20	1-Sep-20	29-Aug-20	24-Aug-20	11-Aug-20	16-Oct-23
	Pressure-Cycle Induced Fatigue	Not Susceptible	2084	2034	2030	2024	2043	2031	2025	2027	2024	2037	2022	2030
	Third-Party Damage*	28-Aug-22	13-Aug-22	13-Sep-20	5-Nov-22	4-Jan-21	3-Jan-21	7-Mar-21	6-Mar-21	27-Feb-21	22-Feb-21	20-Feb-21	16-Feb-21	13-Feb-21

‡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.
~Different tool vendors.

Table 34. 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 to Strauss	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			SMFL				
	Date of Tool Run			5-Oct-2016				
	Tool		MFL		SMFL	SMFL		SMFL
	Date of Tool Run		1-Nov-17		13-Jul-17	13-Jul-17		14-Jul-17
	Tool	MFL					MFL	
	Date of Tool Run	18-Apr-18					25-Oct-18	
	Third-Party Damage							
	Tool			Deformation				
	Date of Tool Run			5-Oct-2016				
	Tool		Deformation		Deformation	Deformation		Deformation
	Date of Tool Run		1-Nov-17		13-Jul-17	13-Jul-17		14-Jul-17
	Tool	Deformation					Deformation	
	Date of Tool Run	18-Apr-18					25-Oct-18	
Next Required Assessment								
	Corrosion	18-Apri-23	1-Nov-22	5-Oct-2021	13-Jul-22	13-Jul-22	25-Oct-23	14-Jul-22
	Pressure-Cycle Induced Fatigue	*Not Susceptible*	*Not Susceptible*	*Not Susceptible*				
	Third-Party Damage	18-Apri-23	1-Nov-22	Oct-5-2021	13-Jul-22	13-Jul-22	25-Oct-23	14-Jul-22

5.2 Integration of DOT HCA Inspection Requirements

Magellan must be compliant with the DOT Integrity Management Rule, 49 CFR 195.452, for HCAs 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 and the lateral from Odessa to Crane.

The HCA rule states that an operator must establish 5-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 5-year interval is not exceeded.

LMC 12A requires an EGP tool to be run every three years on the existing pipeline (between Valve J-1 and Crane). This interval is due to a greater risk of mechanical damage to the existing pipeline. The existing pipeline is often buried shallower than 30 inches in depth below the surface because of burial requirements when the pipeline was built. For the new pipeline extensions, the HCA requirement (49 CFR 195.452) requires an EGP tool to be run every five years. The risk for mechanical damage on the New Pipeline is less due to the pipeline being buried at least 30 inches deep.

5.3 Pipe Replacement Schedule

There were no pipe replacements in 2019.

6 NEW INTEGRITY MANAGEMENT TECHNOLOGIES

6.1 Baker Hughes UltraScan™ Crack Detection ILI Tool

Magellan elected to perform an ILI run incorporating BHGE's UCD tool. This technology purports to have improved crack detection and sizing performance and was used as an alternative as improved technology to running a traditional TFI tool. The UCD tool has approximately 70% more sensors than standard crack detection tools with a higher circumferential resolution, and has the ability to identify more than 20 types of cracks and crack-like features, including girth weld defects, short cracks, hook cracks, toe cracks, crack/SCC colonies, lack of fusion, crack-like ERW, and crack-like DSAW features. The first data set from this tool was received in 2019 and incorporated into the analysis within this report. As use of this tool continues, Magellan will be able to evaluate the impact of its effectiveness in accurately identifying features for its mitigation and monitoring programs.

7 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.
7. The Longhorn Mitigation Plan, September 2000.

APPENDIX A – MITIGATION COMMITMENTS

Table A-1. Longhorn Mitigation Commitments (pg. 1 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
1	Longhorn shall hydrostatically test the hypersensitive (Tier III) and sensitive (Tier II) areas of the pipeline and those portions of the pipeline identified by the Surge Pressure Analysis as being potentially subject to surge pressures in excess of current MASP. See Mitigation Appendix, Item 1 and 9.	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Previous Defects; Establish Safety Factor
2	Longhorn shall "proof test" all portions of the pipeline from the J-1 Valve to Crane Station that have not been hydrostatically tested pursuant to Mitigation Commitment No. 1. See Mitigation Appendix, Item 2	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Previous Defects
3	Longhorn shall replace approximately 19 miles of the existing pipeline over the Edwards Aquifer recharge and contributing zones with thick walled pipe; the pipe will be protected by a concrete barrier. See Mitigation Appendix, Item 3	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Operator Error
4	Longhorn shall perform the following additional cathodic protection mitigation work: (a) Install 13 additional CP ground beds at locations described in Mitigation Appendix, Item 4. (b) Perform interference testing at 20 locations, if necessary, as described in Mitigation Appendix, Item 4. (c) Replace at least 600 feet of coating identified by the CP survey analysis as described in Mitigation Appendix, Item 4. (d) Repair or replace, as necessary, 12 shorted casings identified by the CP survey analysis at the locations described in Mitigation Appendix, Item 4.	Prior to startup / Completed	Corrosion
5	Longhorn shall lower, replace, or recondition, if necessary, the pipe at 12 locations per the Environmental Assessment (including Marble Creek). See Mitigation Appendix, Item 5.	Prior to startup / Completed	Outside Force Damage, Corrosion, and Material Defects
6	Longhorn shall remove stopple fittings at the following locations: Station Nos. 9071+36, 8936+35, and 8796+99 (MP 171.86, 169.25, and 166.61). See Mitigation Appendix, Item 6.	Prior to startup / Completed	Material Defects
7	Longhorn shall excavate the pipeline at two locations, near Satsuma Station and in Waller County, indicated by the 1995 in-line inspection and determine condition and repair, if necessary. See Mitigation Appendix, Item 7.	Prior to startup / Completed	Material Defects and Corrosion
8	Longhorn shall replace the pipeline at the crossing of Rabb's Creek and investigate at least 5 dent locations identified by Kiefner, based upon the 1995 in-line inspection, and repair, if necessary. See Mitigation Appendix, Items 8 and 19.	Prior to startup / Completed	Material Defects, Corrosion, and Outside Force Damage

Table A-2 (continued). Longhorn Mitigation Commitments (pg. 2 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
9	Longhorn shall remediate any maximum allowable surge pressure (MASP) problems identified by Longhorn's most recent Surge Pressure Analysis by hydrostatically testing those portions of the pipeline which the Surge Pressure Analysis indicates could exceed MASPs. The hydrostatic test will requalify the portions of the pipeline which will be tested to a MASP which is within permissible limits as established by the most recent Surge Pressure Analysis. Further, Longhorn will implement appropriate measures in all Tier II and Tier III areas of the pipeline to eliminate the possibility of conditions causing a surge pressure which would exceed maximum operating pressure (MOP). See Mitigation Appendix, Item 9 and Longhorn Mitigation Commitment 34.	Prior to startup / Completed	Material Defects and Corrosion
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 (HRMFL) 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

Table A-3 (continued). Longhorn Mitigation Commitments (pg. 3 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
13	Longhorn shall install an enhanced leak detection and control system which will include a transient model based leak detection system utilizing 9-meter stations (6 clamp on meters and 3 turbine meters). Additionally, a leak detection system will be installed over the Edwards Aquifer Recharge Zone and the Slaughter Creek watershed in the Edwards Aquifer Contributing Zone that will detect a leak of extremely minute volume in 12 to 120 minutes from contact, depending upon the product sensed by the system. That leak detection system will be a buried hydrocarbon sensing cable system designed to meet the leak detection performance specifications described in the preceding sentence. The pipeline system is designed to achieve emergency shut down within 5 minutes of a probable leak indication. See Mitigation Appendix, Item 13.	System installation prior to startup and system operational within 6 months of startup / Completed	Leak Detection and Control
14	Longhorn shall perform close interval pipe to soil potential surveys to survey (a) hypersensitive areas, and (b) pipeline segments which were not surveyed by the 1998 close interval survey (Station Nos. 10753+40 – 10811+06 [MP 203.66 – 204.75], 8897+60 – 8945+40 [MP 168.52 – 169.42], and 1729+24 – 1734+81 [MP 32.75 – 32.86]), and remediate corrosion related conditions identified by the surveys as necessary. See Mitigation Appendix, Item 4 (Areas 12, 13 and 15) and the Longhorn Pipeline System Integrity Plan, section 3.5.1.	Prior to startup / Completed	Corrosion
15	Longhorn shall perform an engineering analysis to verify that all pipeline spans are adequately supported and protected from external loading. Longhorn shall implement the recommendations of such analysis to ensure the stability of such spans. Longhorn shall provide documentary or analytical confirmation of the pipe grade or the pipeline across the Colorado River. See Mitigation Appendix, Item 15.	Prior to startup / Completed	Material Defects, Outside Force Damage and Corrosion, Establish Safety Factors
16	Longhorn shall remove all encroachments along the pipeline right-of-way that could reasonably be expected to obstruct prompt access to the pipeline for routine or emergency repair activities or that could reasonably be expected to hinder Longhorn's ability to promptly detect leaks or other problems. Potential encroachments will be evaluated using the guidelines found in section 3.5.5, Encroachment Procedures of the Longhorn Pipeline System Integrity Plan.	Within one year of startup / Completed	Outside Force Damage, Leak Detection and Control
17	Longhorn shall clear the right-of-way to excellent condition (right-of-way encroachments shall be resolved by Longhorn pursuant to Mitigation Commitment 16). See Mitigation Appendix, Item 17.	Prior to startup and continuously thereafter	Outside Force Damage, Leak Detection and Control

Table A-4 (continued). Longhorn Mitigation Commitments (pg. 4 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
18	Longhorn shall inspect and repair or replace, as necessary, 26 locations identified by Williams in its risk assessment model as areas requiring further investigation. See Mitigation Appendix, Item 18.	Prior to startup / Completed	Outside Force Damage, Material Defects, Corrosion and Previous Defects
19	Longhorn has performed studies evaluating each of the following matters along the pipeline, and shall implement the recommendations of such studies:	Prior to startup / Completed	
	(a) Stress-corrosion cracking potential.		Outside Force Damage, Corrosion, and Material Defects
	(b) Scour, erosion and flood potential.		Outside Force Damage and Corrosion
	(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
			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
21	Longhorn shall increase the frequency of inspections at pump stations to every two and one-half days in sensitive and hypersensitive areas. Additionally, remote cameras for monitoring pump stations will be installed, within 6 months of startup for existing stations, and at future stations prior to startup. See Mitigation Appendix, Item 21.	Continuously after startup	Outside Force Damage, Corrosion, Material Defects, Leak Detection and Control
22	Longhorn shall commission a study that quantifies the costs and benefits of additional valves at the following river and stream crossings: Marble Creek; Onion Creek; Long Branch; Barton Creek; Fitzhugh Creek; Flat Creek; Cottonwood Creek; Hickory Creek; White Oak Creek; Crabapple Creek; Squaw Creek; Threadgill Creek; and James River. Longhorn shall install additional valves if it determines, on the basis of the study, with DOT/OPS concurrence, that additional valves will be beneficial. See Mitigation Appendix, Item 22.	Prior to startup / Completed	Outside Force Damage, Corrosion, Material Defects, and Leak Detection and Control
23	Longhorn shall develop a response center in the middle area of the pipeline which will include available response equipment and personnel such that under normal conditions, a maximum 2-hour full response can be assured. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	Leak Detection and Control

Table A-5 (continued). Longhorn Mitigation Commitments (pg. 5 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
24	Longhorn shall revise its facilities response plan to better address firefighting outside of metropolitan areas (Houston, Austin and El Paso) where HAZMAT units do not exist. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	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
26	Longhorn shall revise its facility response plan to provide for more detailed response planning for areas where high populations of potentially sensitive receptors are on or adjacent to the pipeline right-of-way. See Mitigation Appendix, Item 23, 24 and 26. (Items 23, 24 and 26 are grouped under the heading "Enhanced Facility Response Plan" in the Mitigation Appendix.)	Prior to startup / Completed	Leak Detection and Control
27	Longhorn shall provide evidence (as-built engineering drawings and similar such documentation) that secondary containment was installed, during construction, under and around all storage and relief tanks, in accordance NFPA 30. Longhorn shall install secondary containment at the Cedar Valley pump station in Hays County.	Prior to startup / Completed	Leak Detection and Control
28	Longhorn shall revise its facility response plan, if or as necessary, to make it consistent, to the extent practicable, the referenced plans are Control with the City of Austin's Barton Springs oil spill developed contingency plan and the United States Fish and Wildlife Service's Barton Springs Salamander Recovery Plan. See Mitigation Appendix, Item 28.	Prior to startup / Completed	Leak Detection and Control

Table A-6 (continued). Longhorn Mitigation Commitments (pg. 6 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
29	Longhorn shall provide funding for a contractor (employing personnel with the necessary education, training and experience) to conduct water quality monitoring at each of 12 locations in proximity to stream crossings of the pipeline to determine the presence of gasoline constituents. See Mitigation Appendix, Item 29.	For a period of two years after startup to evaluate the effectiveness of the program and thereafter as dictated by the Longhorn ORA (See Section 4.0).	Leak Detection and Control
30	Longhorn shall provide alternate water supplies to certain water municipalities and private well users as detailed in Longhorn's contingency plans. See Mitigation Appendix, Item 30.	Prior to startup / Completed	Leak Detection and Control
31	Longhorn shall perform a surge pressure analysis prior to any increase in the pumping capacity above those rates for which analyses have been performed or any other change which has the capability to change the surge pressures in the system. Longhorn will be required to submit mitigation measures acceptable to DOT/OPS prior to any such change in the system, which mitigation measures will adequately address any MASP problems on the system identified by the surge pressure analysis.	Prior to any change in the system that has the capability to cause surge pressures to occur on the system.	Material Defects
32	Longhorn shall perform pipe-to-soil potential surveys semi-annually over sensitive and hypersensitive areas (which is twice the frequency required by DOT regulation – 49 CFR 195.573), and corrective measures will be implemented, as necessary, where indicated by the surveys. See Longhorn Pipeline System Integrity Plan, Section 3.5.1.	No more than six months after startup and semi-annually thereafter.	Corrosion
33	(a) Longhorn shall provide the necessary funding to establish as adequate refugium and captive breeding program for the Barton Springs Salamander to offset any losses that might occur in the highly unlikely event of a release that caused the loss of individual salamanders. This program will be conducted in coordination with the Austin Ecological Services Field Office of the U.S. Fish and Wildlife Service; and	Within 30 days of startup / Completed	Potential adverse effects to the Barton Springs Salamander
	(b) Longhorn shall perform conservation measures developed in consultation with the U.S. Fish and Wildlife service to mitigate potential impacts to threatened and endangered specifies in the highly unlikely event that future pipeline construction activities and operation may adversely affect such species or their habitat. See Mitigation Appendix, Item 33.	At any time such activity could have an adverse effect on listed species or habitat.	Potential adverse effects to listed species or habitat

Table A-7 (continued). Longhorn Mitigation Commitments (pg. 7 of 7)

No.	Description	Timing of Implementation	Risk(s) Addressed
34	Longhorn shall implement system changes, through system and equipment modification and/or observance of operating practices, to limit surge pressure to no more than MOP in sensitive and in hypersensitive areas. Such system changes shall include (a) replacement of the pipe at the following locations: 6752+06 – 6758+40 (MP 127.88 – 128.00) and 10489+47 – 10490+00 (MP 198.66 – 198.67) and (b) installation of pressure active by-pass systems at the Brazos, Colorado, Pedernales, and Llano rivers. In addition, Longhorn shall replace one 671 foot section of pipe previously characterized as Grade B. See Mitigation Appendix, Item 34 and Longhorn Mitigation Commitment 9.	Prior to startup and thereafter	Outside Force Damage, Corrosion, Operator Error and Material Defects
35	Longhorn shall not transport products through the pipeline system which contain the additive methyl tertiary butyl ether (MTBE) or similar aliphatic ether additives (e.g., TAME, ETBE, and DIPE) in greater than trace amounts. This limitation with be incorporated into the Longhorn product specifications.	During the operational life of the pipeline system	Potential adverse impacts to water resources
36	Longhorn shall prepare site-specific environmental studies for each new pump station planned for construction. These studies shall be responsive to National Environmental Policy Act (NEPA) requirements as supplements to the EA of the Proposed Longhorn Pipeline System. For each such pump station, Longhorn shall submit the site-specific environmental study to the U.S. DOT no less than 180 days prior to commencement of construction.	Prior to construction of any new pump station	Consistency with NEPA
37	Longhorn shall maintain pollution legal liability insurance of no less than $15 million to cover on-site and off-site third party claims for bodily injury, property damage, and costs of response and clean-up in the event of a release of product from the Longhorn Pipeline System.	Prior to startup and during the operational life of the pipeline system	Financial Assurance
38	Longhorn shall submit periodic reports to DOT/OPS that will include information about the status of mitigation commitment implementation, the character of interim developments as related to mitigation commitments, and the results of mitigation-related studies and analyses. The reports shall also summarize developments related to its ORA. The reports shall be made available to the public.	Quarterly during the first 2 years of system operation and annually thereafter for the operational life of the pipeline system.	Assurance of mitigation commitment implementation and public access to related information
39	The Longhorn Mitigation Plan, and associated Pipeline System Integrity Plan and ORA, shall not be unilaterally changed. The LMP may be modified only after Longhorn has reviewed proposed changes with DOT/OPS and has received from DOT/OPS written concurrence with the proposed modifications.	During the operational life of the pipeline system	Assurance of full implementation of the Longhorn Mitigation Commitments

APPENDIX B – NEW DATA USED IN THIS ANALYSIS

Table B-1. 2019 ORA Data List (pg. 1 of 2)

Topics	Data / Notes
1. Pipeline and Facilities	• Alignment Sheets – 6643 – E. Houston to 9th Street – 6645 – E. Houston to El Paso • Linefill Sheets • Maps and Flow Schematics (strip maps, KMZ files) • Tier Classifications • List of HCAs • Facility Inspection Reports – Bastrop (7/19) – Buckhorn (10/19) – Cartman (8/19) – Cedar Valley (5/19) – Eckert (5/19) – James River (8/19) – Kimble (8/19) – Satsuma (10/19) – Warda (7/19) – Barnhart (10/19) – Crane (10/19) – Texon (10/19)
2. Flow and Pressure Data	• Monthly spreadsheet of flow and pressures • Service Interruptions
3. ILI & Anomaly Investigation Reports	• ILI Reports – E. Houston to Speed Jct – GMFL – E. Houston to Speed Jct – Deformation – Satsuma to E. Houston – MFL – Satsuma to E. Houston – UCD – Satsuma to E. Houston – Deformation – Warda to Buckhorn – MFL – Warda to Buckhorn – Deformation – Crane to Texon – MFL – Crane to Texon – UCD – Crane to Texon – Deformation – El Paso to Strauss – MFL – El Paso to Strauss – Deformation • Tool specifications
4. Hydrostatic Testing Reports	• No hydrostatic tests performed in 2019.
5. Corrosion Management Surveys & Reports	• Cathodic Protection Data – Rectifier Inspection Reports – Rectifier Maintenance Reports – Test Point Exception Reports • Coupon Data • Atmospheric Inspection Reports • Tank Inspections • 7.04-ADM-001 Corrosion Control Program

Table B-2 (continued). 2019 ORA Data List (pg. 2 of 2)

Topics	Data / Notes
6. Earth Movement & Water Forces	• Fault monitoring (semi-annual reports) • River crossing and scouring surveys – Pin Oak Creek • Master River Inspections Spreadsheet • Flood monitoring (daily)
7. Maintenance and Inspection Reports	• Maintenance Reports • Non-destructive Evaluation (NDE) • Positive Material Identification (PMI) • Mainline Valve Inspection Reports • Longhorn Year-end Preventive Maintenance Tasks Summary
8. Project Work Progress and Quality Control Reports	• CMS Year-End Task Report • Preventive Maintenance Summary • Scorecards • Annual Asset Integrity Summary for 2019 • 2019 Annual Commitment Implementation Status Report • 2019 Annual Self-Audit
9. One-Call Violations and Third-Party Damage Prevention Data	• Third-Party Damage Report • One-call list • Encroachments • Patrol Data • Website Visits • Damage Prevention Training
10. Incident, Root Cause and Metallurgical Failure Analysis Reports	• Incident Data and Incident Investigation Reports
11. Other LPSIP / Risk Assessment Studies, Evaluations and other Program Data	• Process Hazard Analyses – Buckhorn ROV Project What-If – James River ROV Project What-If – Kimble ROV Project What-If – Warda ROV Project What-If – Barnhart ROV Project What-If – Cartman ROV Project What-If – Texon ROV Project What-If – El Paso Facility
12. Leak Detection	• Pipeline Leak Monitoring (PLM) Records • Description of System(s)
13. Integrity Management Plan (IMP) & Related Procedures	• IMP Plan and related procedures

B.2. Major Pipeline Incidents, Industry, or Agency Advisories Affecting Pipeline Integrity

B.2.1 PHMSA Advisories

None were applicable to the Longhorn Pipeline during 2019.

B.2.2 PHMSA Notices

Pipeline Safety: Safety of Hazardous Liquid Pipelines, 10/1/2019. PHMSA published this document in response to congressional mandates, NTSB and GAO recommendations, lessons learned, and public input. PHMSA is requiring:

- Reporting requirements for certain hazardous liquid gravity and rural gathering pipelines
- Inspection of pipelines located in areas affected by extreme weather and natural disasters
- Integrity assessments for 'piggable' onshore hazardous liquid pipelines segments located outside of HCA; assessment required at least once every 10 years
- Extended the use of leak detection systems from HCAs to include all regulated, non-gathering hazardous liquid pipelines
- All pipelines in HCA or affecting HCA need to be 'piggable' within 20 years.

B.2.3 DOT Regulations

No new regulations affecting the Longhorn ORA occurred in 2019.

B.2.4 Literature Reviewed

See references.

APPENDIX C – APPROACH TO API 1163 VERIFICATION

Approach to API 1163 Verification

API 1163 2nd Edition, April 2013 describes methods in Section 7 and Section 8 that can be applied to verify that the ILI tool was working as expected and reported inspection results are within the performance specification for the pipeline being inspected. Within the Standard, a distinction is made between results with and without field verification measurements. API 1163 Section 7 provides information for what the ILI Vendor is to provide regarding pre-, mid-, and post-inspection checks for proper tool runs. API 1163 Section 8 Figure 6 (Figure C-1 in this document) describes a process for validating ILI measurements using three levels of validation, shown in Figure C-2.

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

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

The validation levels differ based on the risk of the pipeline segment and the amount of validation data.

Validation Level 1 (Annex C):

- 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 low levels of 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.

Validation Level 2 (Annex C):

- 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 typically be greater than or equal to five, but not be 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 (§8.2.6)

Validation Level 3 applies to pipelines with a higher risk of consequence or probability of failure that has 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 upon 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. Some actions to consider are: performing additional validation digs to gather more information to possibly improve the current tool performance, accept the determined tool performance as-is and adjust the depth accuracy applied to the reported ILI features; or have the ILI Vendor regrade the data. Figure C-1 shows API 1163 Section 8 Figure 6, which summarizes the process for evaluation of system results. For clarity of wording in the flow chart, "historical data" is taken to mean the data limited to the particular line, whereas "large-scale historical data" is taken to mean the data on this line, as well as any similar diameter lines with the same ILI tool type used for inspection.

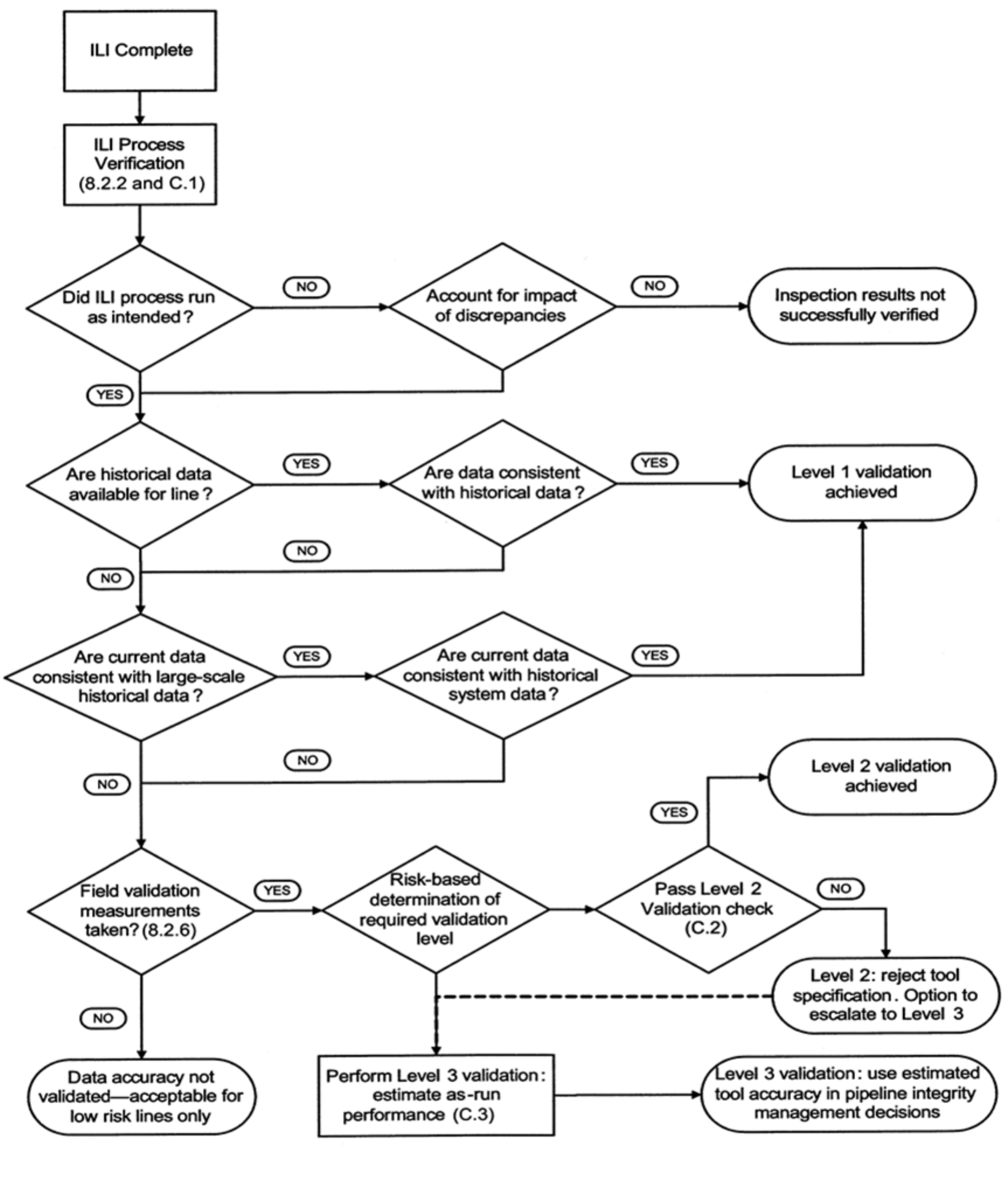

Figure 6—Inspection Results Verification and Validation Process

Figure C-1. Evaluation of System Results from API 1163 Section 8 Figure 6

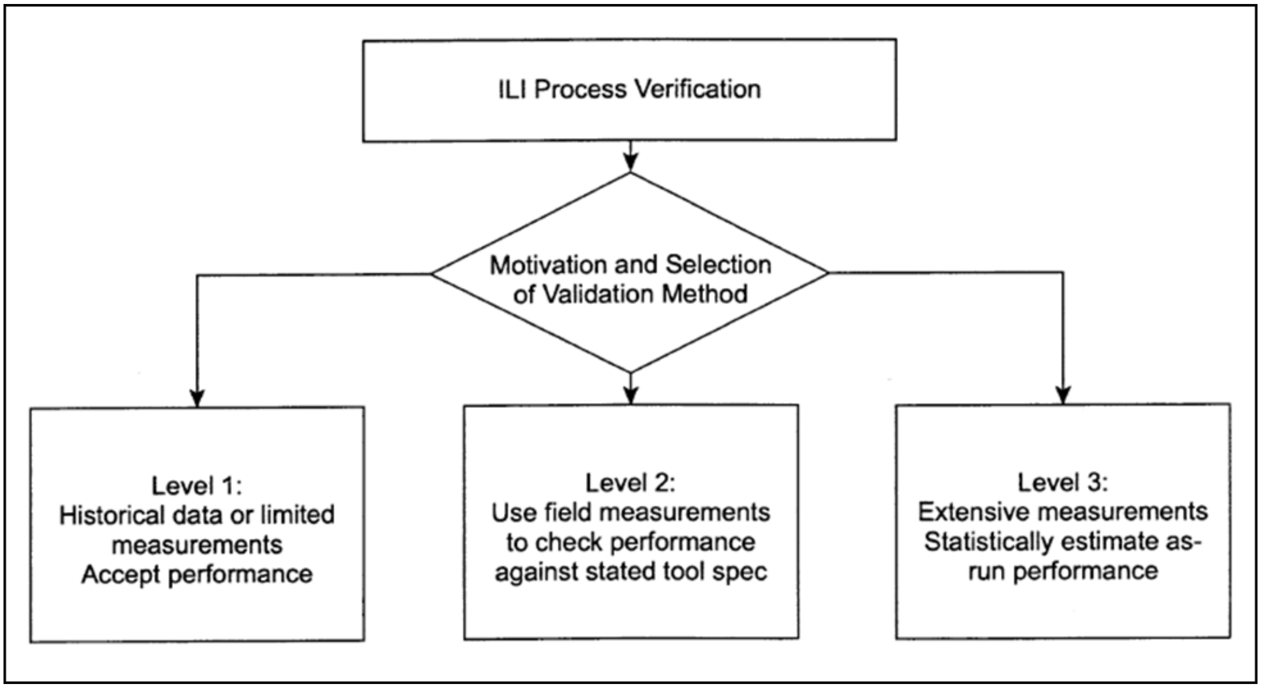

Figure C-2. Overview of Three Levels of Validation

APPENDIX D – THRESHOLD ANOMALY FATIGUE EVALUATION RESULTS

Table D-1 and Table D-2 show the fatigue lives predicted for threshold anomalies accounting for pipe properties and attribute changes including wall thickness, grade, pipe OD, elevation changes, and nearness to the pump station discharge locations. The fatigue results are presented in increasing order of time to failure or reassessment interval.

Note that, in cases where the calculated times to failure were in excess of 500 years, an artificial cap of 500 years was imposed to reduce the calculation time. Also, note that the reassessment intervals were calculated using a safety factor of 2.22 consistent with the specification for safety factor in the Magellan ORA Manual which requires that the reassessment interval be taken as 45% of the shortest fatigue life.

Table D-1. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations on Refined Products Pipeline

Pipeline Segment	Assessment Location	OD (inch)	Wall Thickness (inch)	Grade	Elevation (feet)	Year of Installation	Threshold Flaw Depth (inch)	Threshold Anomaly Depth at ILI Detection Threshold (% WT)	Defect Failure Press (psig)	Calculated Time to Failure (years)	Re-assessment Interval (years)	Re-assessment Due Date
Crane-Cottonwood	27879+57	18	0.500	X52	2,621	2008	0.050	10%	3,409	500.0	225.2	03/25/2233
Crane-Cottonwood	30429+00	18	0.281	X65	3,843	1998	0.028	10%	2,291	500.0	225.2	03/26/2223
Crane-Cottonwood	30429+60	18	0.375	X65	3,840	2008	0.038	10%	3,069	500.0	225.2	03/25/2233
Crane-Cottonwood	30430+16	18	0.375	X52	3,841	2008	0.038	10%	2,551	500.0	225.2	03/25/2233
Cottonwood-El Paso	36642+98	18	0.375	X65	4,017	1998	0.038	10%	3,068	500.0	225.2	03/26/2223
Cottonwood-El Paso	36664+58	18	0.281	X65	4,022	1998	0.028	10%	2,291	500.0	225.2	03/26/2223
Cottonwood-El Paso	36665+05	18	0.375	X52	4,022	1998	0.038	10%	2,551	500.0	225.2	03/26/2223

Table D-2. Pressure-Cycle-Induced Fatigue Cracking Analysis Locations in Crude Pipeline (pg. 1 of 3)

Pipeline Segment	Assessment Location	OD (inch)	Wall Thickness (inch)	Grade	Elevation (feet)	Year of Installation	Threshold Flaw Depth (inch)	Threshold Anomaly Depth at ILI Detection Threshold (% WT)	Defect Failure Press (psig)	Calculated Time to Failure (years)	Re-assessment Interval (years)	Re-assessment Due Date
Texon-Barnhart	21999+54	18	0.250	X52	2,675	1953	0.125	50	898	16.4	7.4	12/28/2022
Bastrop-Warda	7483+48	18	0.281	X45	395	1950	0.141	50	981	19.2	8.7	08/09/2024
Cartman-Kimble	18168+81	18	0.281	X45	2,445	1950	0.141	50	952	19.6	8.9	07/04/2024
James River-Eckert	13733+47	18	0.281	X45	1,705	1950	0.141	50	965	21.5	9.7	04/30/2025
Cartman-Kimble	18173+61	18	0.281	X65	2,445	1950	0.141	50	952	22.3	10.0	09/13/2025
Kimble-James River	14758+39	18	0.219	X52	1,669	1967	0.110	50	898	27.0	12.2	10/28/2027
Cartman-Kimble	17883+21	18	0.281	X52	2,399	1950	0.141	50	952	28.1	12.7	04/30/2028
Cartman-Kimble	18174+51	18	0.312	X45	2,445	1950	0.156	50	952	30.7	13.8	06/22/2029
Warda-Buckhorn	5702+41	18	0.281	X45	380	1950	0.141	50	965	31.6	14.2	03/06/2030
Kimble-James River	15584+59	18	0.281	X45	2,223	1950	0.141	50	898	33.2	15.0	08/17/2030
Bastrop-Warda	7157+10	18	0.281	X65	348	1950	0.141	50	981	34.9	15.7	09/05/2031
Eckert-Cedar Valley	12033+42	18	0.281	X45	1,736	1950	0.141	50	959	35.0	15.8	09/12/2031
Warda-Buckhorn	5961+54	18	0.312	X45	359	1950	0.156	50	965	36.2	16.3	04/06/2032
Buckhorn-Satsuma	3587+47	18	0.281	X45	171	1950	0.141	50	787	40.8	18.4	05/05/2034
James River-Eckert	13585+57	18	0.312	X60	1,777	1950	0.156	50	965	43.4	19.6	03/14/2035
Barnhart-Cartman	19726+03	18	0.312	X45	2,603	1950	0.156	50	898	49.2	22.2	10/22/2037
Barnhart-Cartman	19262+28	18	0.281	X45	2,533	1950	0.141	50	898	52.8	23.8	05/31/2039
Eckert-Cedar Valley	12029+82	18	0.312	X45	1,744	1950	0.156	50	959	54.4	24.5	06/11/2040
Cedar Valley-Bastrop	8965+58	18	0.281	X45	790	1950	0.141	50	965	61.4	27.7	08/08/2043
James River-Eckert	13735+06	18	0.375	B	1,712	1950	0.188	50	965	66.3	29.9	07/04/2045
Texon-Barnhart	21351+54	18	0.312	X45	2,666	1950	0.156	50	898	78.0	35.1	10/02/2050
Bastrop-Warda	6789+27	18	0.312	X45	470	1950	0.156	50	981	79.0	35.6	07/05/2051
James River-Eckert	13586+77	18	0.375	X65	1,778	1950	0.188	50	965	89.7	40.4	01/12/2056
James River-Eckert	13448+47	18	0.375	X42	1,842	1950	0.188	50	965	98.7	44.5	02/02/2060
Cedar Valley-Bastrop	8896+16	18	0.312	X45	708	1950	0.156	50	965	103.0	46.4	04/27/2062
Bastrop-Warda	7113+00	18	0.375	X45	337	1950	0.188	50	981	108.0	48.7	08/09/2064
James River-Eckert	13435+87	18	0.385	X65	1,783	1950	0.193	50	965	117.5	52.9	07/23/2068
Warda-Buckhorn	5518+21	18	0.375	B	512	1950	0.188	50	965	122.7	55.3	03/19/2071
James River-Eckert	12039+26	18	0.312	X45	1,717	1950	0.156	50	965	124.4	56.0	09/04/2071
James River-Eckert	13200+97	18	0.375	X52	1,511	1950	0.188	50	965	132.3	59.6	03/20/2075
Bastrop-Warda	5965+07	18	0.312	X65	355	1967	0.156	50	981	147.2	66.3	03/26/2082
Bastrop-Warda	6797+67	18	0.375	X42	430	1950	0.188	50	981	161.3	72.7	08/04/2088
Buckhorn-Satsuma	3372+81	18	0.375	X45	141	1950	0.188	50	787	172.3	77.6	07/26/2093
Kimble-James River	14604+19	18	0.375	X45	1,511	1950	0.188	50	898	263.3	118.6	04/04/2134

Table D-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis Locations in Crude Pipeline (pg. 2 of 3)

Pipeline Segment	Assessment Location	OD (inch)	Wall Thickness (inch)	Grade	Elevation (feet)	Year of Installation	Threshold Flaw Depth (inch)	Threshold Anomaly Depth at ILI Detection Threshold (% WT)	Defect Failure Press (psig)	Calculated Time to Failure (years)	Re-assessment Interval (years)	Re-assessment Due Date
Buckhorn-Satsuma	3073+11	18	0.375	X65	177	1950	0.188	50	787	272.5	122.7	09/12/2138
James River-Eckert	12186+09	18	0.375	X70	1,606	1950	0.188	50	965	280.3	126.3	11/25/2141
Buckhorn-Satsuma	1955+44	18	0.281	X52	137	1950	0.141	50	787	301.9	136.0	12/23/2151
EHS-9th Str. (U/S of Speed JCT)	0+02	20	0.375	B	37	2010	0.038	10	1,168	345.1	155.5	03/23/2170
EHS-9th Str. (U/S of Speed JCT)	0+14	20	0.375	X52	37	2010	0.038	10	1,168	356.8	160.7	06/24/2175
Barnhart-Cartman	19716+78	18	0.281	X65	2,605	1998	0.028	10	898	401.4	180.8	06/21/2196
James River-Eckert	13371+07	18	0.281	X65	1,649	2013	0.028	10	964	419.8	189.1	09/18/2204
EHS-9th Str. (U/S of Speed JCT)	188+83	20	0.312	X52	17	1998	0.031	10	1,168	420.9	189.6	05/05/2204
Warda-Buckhorn	4539+01	18	0.385	X65	319	1950	0.193	50	965	448.5	202.0	12/28/2217
Eckert-Cedar Valley	11439+42	18	0.500	B	1,705	2012	0.050	10	2,475	500.0	225.2	02/25/2241
Buckhorn-Satsuma	3386+91	18	0.500	X42	150	2012	0.050	10	2,858	500.0	225.2	03/11/2241
Buckhorn-Satsuma	1803+16	18	0.375	B	126	1947	0.188	50	1,522	500.0	225.2	03/11/2241
Texon-Barnhart	21353+94	18	0.375	X65	2,665	1999	0.038	10	3,043	500.0	225.2	11/02/2240
Buckhorn-Satsuma	3371+01	18	0.375	X65	142	2012	0.038	10	3,045	500.0	225.2	03/11/2241
Barnhart-Cartman	18852+18	18	0.375	X65	2,501	2000	0.038	10	3,052	500.0	225.2	11/15/2240
Buckhorn-Satsuma	3386+31	18	0.375	X42	150	1998	0.038	10	2,128	500.0	225.2	03/11/2241
Cartman-Kimble	18037+41	18	0.500	X52	2,426	2012	0.050	10	3,390	500.0	225.2	11/20/2240
EHS-9th Str. (U/S of Speed JCT)	235+10	20	0.344	X52	18	1998	0.034	10	2,041	500.0	225.2	12/25/2239
Warda-Buckhorn	4080+61	18	0.385	X65	229	2000	0.039	10	3,147	500.0	225.2	03/09/2241
Barnhart-Cartman	18860+28	18	0.375	X60	2,501	2000	0.038	10	2,858	500.0	225.2	11/15/2240
Barnhart-Cartman	18303+24	18	0.500	X52	2,452	2012	0.050	10	3,405	500.0	225.2	11/15/2240
Barnhart-Cartman	19717+38	18	0.312	X52	2,605	1998	0.031	10	1,802	500.0	225.2	11/15/2240
Kimble-James River	14596+69	18	0.375	X45	1,533	2013	0.038	10	2,258	500.0	225.2	11/23/2240
Bastrop-Warda	7360+80	18	0.375	B	394	2002	0.038	10	1,785	500.0	225.2	03/04/2241
Buckhorn-Satsuma	2025+86	18	0.375	X52	143	1950	0.188	50	2,098	500.0	225.2	03/11/2241
James River-Eckert	12921+69	18	0.375	X65	1,698	2012	0.038	10	3,046	500.0	225.2	11/10/2240
Texon-Barnhart	21388+14	18	0.281	X65	2,664	1998	0.028	10	2,162	500.0	225.2	11/02/2240
Texon-Barnhart	21599+94	18	0.385	X65	2,723	2000	0.039	10	3,117	500.0	225.2	11/02/2240
Buckhorn-Satsuma	3064+08	18	0.281	X45	179	2013	0.028	10	1,670	500.0	225.2	03/11/2241
Texon-Barnhart	21998+94	18	0.375	X42	2,674	2012	0.038	10	2,081	500.0	225.2	11/02/2240
Kimble-James River	15585+23	18	0.375	X52	2,221	1998	0.038	10	2,513	500.0	225.2	11/23/2240
Eckert-Cedar Valley	11499+12	18	0.281	X45	1,648	2012	0.028	10	1,655	500.0	225.2	02/25/2241
Cedar Valley-Bastrop	9590+73	18	0.375	X65	1,032	2002	0.038	10	2,995	500.0	225.2	03/01/2241
Barnhart-Cartman	18862+38	18	0.312	X60	2,501	2000	0.031	10	2,358	500.0	225.2	11/15/2240

Table D-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis Locations in Crude Pipeline (pg. 3 of 3)

Pipeline Segment	Assessment Location	OD (inch)	Wall Thickness (inch)	Grade	Elevation (feet)	Year of Installation	Threshold Flaw Depth (inch)	Threshold Anomaly Depth at ILI Detection Threshold (% WT)	Defect Failure Press (psig)	Calculated Time to Failure (years)	Re-assessment Interval (years)	Re-assessment Due Date
Eckert-Cedar Valley	11389+62	18	0.385	X65	1,585	2000	0.039	10	3,137	500.0	225.2	02/25/2241
Bastrop-Warda	7115+40	18	0.385	X65	337	2000	0.039	10	3,107	500.0	225.2	03/04/2241
Buckhorn-Satsuma	3071+61	18	0.385	X65	177	2002	0.039	10	3,139	500.0	225.2	03/11/2241
Barnhart-Cartman	18561+24	18	0.375	X52	2,477	2007	0.038	10	2,541	500.0	225.2	11/15/2240
Barnhart-Cartman	19265+88	18	0.385	X65	2,532	2000	0.039	10	3,129	500.0	225.2	11/15/2240
Warda-Buckhorn	5041+21	18	0.375	X52	391	2012	0.038	10	2,540	500.0	225.2	03/09/2241
Barnhart-Cartman	18853+98	18	0.312	X65	2,501	2000	0.031	10	2,518	500.0	225.2	11/15/2240
Warda-Buckhorn	5945+30	18	0.375	X65	315	2002	0.038	10	2,961	500.0	225.2	03/09/2241
Cartman-Kimble	17307+51	18	0.375	X52	2,271	2002	0.038	10	2,532	500.0	225.2	11/20/2240
Buckhorn-Satsuma	3373+11	18	0.375	X45	141	1998	0.038	10	2,251	500.0	225.2	03/11/2241
EHS-9th Str. (U/S of Speed JCT)	403+64	20	0.500	X42	0	2011	0.050	10	2,576	500.0	225.2	12/25/2239
Cartman-Kimble	17586+21	18	0.385	X65	2,414	2000	0.039	10	3,113	500.0	225.2	11/20/2240
Buckhorn-Satsuma	2496+20	18	0.281	X65	176	2002	0.028	10	2,281	500.0	225.2	03/11/2241
Barnhart-Cartman	18180+24	18	0.375	X45	2,446	2012	0.038	10	2,253	500.0	225.2	11/15/2240
Warda-Buckhorn	4027+51	18	0.375	X52	340	1950	0.188	50	1,556	500.0	225.2	03/09/2241
Cedar Valley-Bastrop	9561+68	18	0.385	X65	973	2002	0.039	10	3,092	500.0	225.2	03/01/2241
Cedar Valley-Bastrop	7828+82	18	0.500	X65	503	2012	0.050	10	4,098	500.0	225.2	03/01/2241
Texon-Barnhart	22000+11	18	0.375	B	2,675	2012	0.038	10	1,798	500.0	225.2	11/02/2240
Cedar Valley-Bastrop	8430+98	18	0.281	X65	553	2013	0.028	10	2,269	500.0	225.2	03/01/2241
Buckhorn-Satsuma	1947+38	18	0.375	X52	136	2010	0.038	10	2,549	500.0	225.2	03/11/2241
Bastrop-Warda	6887+67	18	0.375	X52	356	1995	0.038	10	2,531	500.0	225.2	03/04/2241
Cedar Valley-Bastrop	9099+68	18	0.375	X52	865	2002	0.038	10	2,535	500.0	225.2	03/01/2241
Buckhorn-Satsuma	1983+64	18	0.375	B	142	1984	0.038	10	1,853	500.0	225.2	03/11/2241
Warda-Buckhorn	4506+01	18	0.281	X45	338	2012	0.028	10	1,682	500.0	225.2	03/09/2241
EHS-9th Str. (U/S of Speed JCT)	187+12	20	0.375	X60	19	2013	0.038	10	2,516	500.0	225.2	12/25/2239

APPENDIX E – CRACK DETECTION ILI ANOMALY FATIGUE EVALUATION RESULTS

Table E-1 and Table E-2 show the fatigue lives predicted for anomalies by the crack detection ILI. The fatigue results are presented in increasing order of time to failure or reassessment interval of the as-called anomaly sizes.

Note that in cases where the calculated times to failure were in excess of 500 years, an artificial cap of 500 years was imposed to reduce the calculation time. Also, note that the reassessment intervals were calculated using a safety factor of 2.22 consistent with the specification for safety factor in the Magellan ORA Manual which requires that the reassessment interval be taken as 45% of the shortest fatigue life.

Table E-1. Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 1 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
23466+39	2,784	18	0.246	52,000	4.472	0.091	11.4	2/25/2030
22325+71	2,666	18	0.246	52,000	5.296	0.086	14.0	10/7/2032
22502+26	2,698	18	0.256	52,000	28.834	0.067	14.7	6/17/2033
24060+59	2,525	18	0.256	52,000	2.471	0.084	17.4	3/11/2036
22502+30	2,698	18	0.256	52,000	20.243	0.067	18.8	8/9/2037
23866+47	2,585	18	0.246	52,000	2.589	0.079	18.9	9/14/2037
23568+68	2,715	18	0.246	52,000	5.414	0.071	19.4	3/20/2038
24080+38	2,540	18	0.285	65,000	3.766	0.086	22.5	4/12/2041
22325+67	2,666	18	0.246	52,000	3.060	0.086	24.7	6/25/2043
23400+62	2,788	18	0.256	52,000	1.530	0.125	26.2	1/4/2045
24015+71	2,539	18	0.246	52,000	3.531	0.052	31.1	11/13/2049
22041+83	2,663	18	0.246	52,000	2.942	0.071	33.5	5/2/2052
23009+60	2,702	18	0.256	52,000	2.942	0.084	37.7	7/10/2056
22330+21	2,664	18	0.250	52,000	3.295	0.073	38.6	5/31/2057
22528+36	2,697	18	0.246	52,000	1.883	0.091	38.9	9/16/2057
22274+39	2,674	18	0.256	52,000	4.001	0.072	39.0	10/20/2057
23905+26	2,577	18	0.256	52,000	3.766	0.054	39.4	2/27/2058
22502+03	2,698	18	0.256	52,000	33.189	0.054	39.7	7/2/2058
22502+00	2,697	18	0.256	52,000	30.129	0.054	40.8	8/1/2059
23603+80	2,678	18	0.246	52,000	4.825	0.052	43.5	4/2/2062
23538+93	2,763	18	0.256	52,000	2.942	0.067	44.0	10/15/2062
23973+77	2,561	18	0.256	52,000	2.471	0.054	44.3	2/7/2063
23053+11	2,681	18	0.256	52,000	1.295	0.118	44.7	7/16/2063
22502+28	2,698	18	0.256	52,000	10.004	0.059	45.3	2/15/2064
23574+82	2,712	18	0.256	52,000	3.766	0.059	47.4	3/8/2066
23591+08	2,691	18	0.256	52,000	1.648	0.079	47.4	3/19/2066
23983+38	2,549	18	0.256	52,000	3.766	0.046	47.9	9/27/2066
24015+66	2,539	18	0.246	52,000	4.119	0.039	48.9	9/20/2067
24040+95	2,531	18	0.246	52,000	1.059	0.059	51.5	4/1/2070

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 2 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22169+17	2,655	18	0.256	52,000	5.061	0.059	51.6	5/19/2070
24040+22	2,531	18	0.256	52,000	7.532	0.038	52.3	1/28/2071
22082+18	2,658	18	0.246	52,000	1.412	0.079	52.5	4/19/2071
23717+74	2,630	18	0.246	52,000	2.354	0.052	53.0	10/28/2071
23464+41	2,785	18	0.246	52,000	2.589	0.059	53.0	11/3/2071
23824+96	2,592	18	0.246	52,000	1.412	0.059	53.3	1/22/2072
23316+24	2,796	18	0.246	52,000	5.767	0.052	53.4	3/13/2072
22502+13	2,698	18	0.256	52,000	12.122	0.054	53.9	9/6/2072
23960+12	2,561	18	0.246	52,000	1.765	0.047	54.7	6/13/2073
23957+54	2,563	18	0.246	52,000	0.942	0.066	55.0	10/7/2073
23637+28	2,666	18	0.246	52,000	1.059	0.079	55.6	6/4/2074
23710+02	2,634	18	0.256	52,000	2.825	0.054	55.6	6/8/2074
22316+35	2,666	18	0.246	52,000	1.530	0.079	56.8	8/24/2075
23060+85	2,696	18	0.246	52,000	3.531	0.059	57.2	1/11/2076
22528+44	2,697	18	0.246	52,000	1.295	0.091	57.8	8/6/2076
23538+79	2,764	18	0.256	52,000	1.412	0.079	58.1	11/22/2076
22502+15	2,698	18	0.256	52,000	9.651	0.054	58.6	5/25/2077
23736+57	2,624	18	0.246	52,000	1.412	0.059	58.7	7/4/2077
22656+09	2,713	18	0.256	52,000	1.883	0.084	58.8	7/19/2077
24047+56	2,530	18	0.246	52,000	6.002	0.032	59.1	12/11/2077
23395+80	2,792	18	0.246	52,000	3.648	0.052	60.1	11/26/2078
23293+68	2,769	18	0.246	52,000	1.177	0.086	60.4	3/11/2079
23532+45	2,776	18	0.246	52,000	1.295	0.071	60.7	6/27/2079
24012+12	2,541	18	0.246	52,000	1.059	0.052	61.9	8/27/2080
22316+25	2,666	18	0.246	52,000	2.001	0.066	62.1	11/11/2080
24001+84	2,543	18	0.246	52,000	1.059	0.052	62.6	6/1/2081
23529+07	2,774	18	0.256	52,000	1.530	0.072	63.3	1/26/2082
22496+50	2,697	18	0.256	52,000	7.768	0.054	63.3	2/21/2082
22537+13	2,698	18	0.256	52,000	1.883	0.079	64.0	10/3/2082
23983+37	2,549	18	0.256	52,000	4.001	0.038	64.1	11/12/2082

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 3 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
23901+65	2,578	18	0.246	52,000	2.589	0.039	64.6	5/11/2083
22519+65	2,698	18	0.246	52,000	1.412	0.079	66.7	7/1/2085
22237+61	2,661	18	0.256	52,000	3.178	0.059	67.0	10/30/2085
22502+17	2,698	18	0.256	52,000	6.591	0.054	67.4	2/25/2086
24048+17	2,530	18	0.256	52,000	0.942	0.059	67.6	6/11/2086
24006+01	2,543	18	0.256	52,000	2.942	0.038	67.9	9/2/2086
22205+98	2,659	18	0.246	52,000	2.118	0.059	67.9	9/14/2086
22614+78	2,707	18	0.256	52,000	4.237	0.059	68.0	10/26/2086
24012+05	2,541	18	0.246	52,000	3.531	0.032	68.5	4/14/2087
23428+08	2,762	18	0.256	52,000	1.765	0.067	68.9	9/28/2087
22261+55	2,670	18	0.246	52,000	3.295	0.052	69.5	4/4/2088
23966+15	2,562	18	0.256	52,000	8.944	0.033	70.0	10/1/2088
23948+94	2,567	18	0.246	52,000	0.824	0.059	71.0	10/17/2089
22830+50	2,662	18	0.246	52,000	1.648	0.071	71.6	6/13/2090
23816+52	2,597	18	0.246	52,000	2.471	0.039	72.2	1/10/2091
22840+70	2,646	18	0.256	52,000	1.295	0.092	72.4	3/18/2091
23445+69	2,774	18	0.246	52,000	2.236	0.052	72.5	4/20/2091
23771+58	2,602	18	0.256	52,000	1.295	0.059	72.6	6/9/2091
22403+42	2,662	18	0.256	52,000	4.708	0.054	73.1	12/10/2091
22632+38	2,710	18	0.256	52,000	1.648	0.079	73.4	3/29/2092
23612+46	2,673	18	0.246	52,000	0.824	0.079	73.9	8/27/2092
24019+76	2,537	18	0.246	52,000	0.824	0.052	74.3	1/22/2093
23845+50	2,591	18	0.256	52,000	0.942	0.067	74.3	2/7/2093
22502+19	2,698	18	0.256	52,000	4.943	0.054	74.7	7/17/2093
23983+43	2,549	18	0.256	52,000	2.354	0.038	75.0	10/18/2093
23308+00	2,785	18	0.256	52,000	1.765	0.067	76.1	11/25/2094
22944+94	2,629	18	0.246	52,000	3.531	0.052	76.2	12/20/2094
22501+88	2,697	18	0.256	52,000	14.476	0.046	77.0	10/12/2095
23521+84	2,767	18	0.256	52,000	2.236	0.054	77.2	1/8/2096
23439+51	2,770	18	0.256	52,000	1.295	0.072	78.5	4/7/2097

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 4 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22807+78	2,654	18	0.246	52,000	2.236	0.059	78.8	8/17/2097
22502+11	2,698	18	0.256	52,000	13.064	0.046	78.9	8/27/2097
23999+74	2,543	18	0.246	52,000	2.118	0.032	79.8	7/27/2098
22945+89	2,626	18	0.246	52,000	1.177	0.079	79.9	9/30/2098
22151+61	2,646	18	0.256	52,000	6.120	0.046	80.2	12/29/2098
23996+83	2,544	18	0.256	52,000	1.177	0.046	80.8	8/9/2099
22325+60	2,666	18	0.246	52,000	1.059	0.079	81.1	11/25/2099
24023+50	2,536	18	0.256	52,000	1.648	0.038	82.0	11/3/2100
23442+16	2,769	18	0.246	52,000	1.295	0.059	84.9	8/29/2103
23087+02	2,662	18	0.256	52,000	8.238	0.046	85.8	8/17/2104
24028+80	2,534	18	0.256	52,000	2.236	0.033	86.4	3/23/2105
22461+31	2,673	18	0.256	52,000	1.765	0.067	86.6	5/11/2105
22486+89	2,693	18	0.246	52,000	1.412	0.066	87.0	11/6/2105
23728+60	2,629	18	0.256	52,000	3.531	0.038	88.3	1/30/2107
23158+08	2,752	18	0.246	52,000	1.295	0.066	88.5	5/1/2107
23983+38	2,549	18	0.256	52,000	2.471	0.033	88.5	5/7/2107
23651+85	2,658	18	0.256	52,000	1.177	0.059	88.6	6/4/2107
24043+13	2,530	18	0.256	52,000	1.295	0.038	89.5	4/7/2108
24000+46	2,543	18	0.256	52,000	1.412	0.038	90.4	3/4/2109
24015+78	2,539	18	0.246	52,000	2.471	0.027	91.8	7/22/2110
22721+23	2,700	18	0.246	52,000	1.765	0.059	92.1	12/7/2110
23864+26	2,585	18	0.256	52,000	0.942	0.054	92.3	1/23/2111
22758+47	2,698	18	0.246	52,000	3.766	0.047	92.4	2/25/2111
22279+25	2,672	18	0.246	52,000	2.589	0.047	92.9	9/23/2111
23933+21	2,572	18	0.256	52,000	1.059	0.046	93.2	12/25/2111
23434+38	2,771	18	0.256	52,000	1.059	0.072	94.0	11/5/2112
22325+62	2,666	18	0.246	52,000	1.177	0.066	94.1	11/8/2112
22406+99	2,661	18	0.256	52,000	1.530	0.067	94.2	1/1/2113
23615+89	2,673	18	0.246	52,000	1.295	0.047	95.0	10/28/2113
23651+31	2,659	18	0.256	52,000	0.824	0.072	95.7	6/21/2114

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 5 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22661+48	2,713	18	0.256	52,000	1.648	0.067	96.1	11/22/2114
22354+97	2,665	18	0.256	52,000	1.883	0.059	96.6	6/13/2115
24017+51	2,538	18	0.256	52,000	1.648	0.033	97.2	12/24/2115
23727+74	2,629	18	0.246	52,000	3.060	0.032	98.1	11/25/2116
22372+74	2,662	18	0.256	52,000	2.354	0.054	98.5	4/11/2117
22100+06	2,662	18	0.256	52,000	2.825	0.046	98.9	9/12/2117
22045+68	2,662	18	0.246	52,000	1.295	0.052	99.2	12/20/2117
23960+82	2,562	18	0.256	52,000	1.883	0.033	99.2	1/8/2118
24000+46	2,543	18	0.256	52,000	5.885	0.026	99.3	2/23/2118
23998+25	2,543	18	0.256	52,000	1.648	0.033	99.5	4/3/2118
23925+54	2,574	18	0.256	52,000	2.001	0.033	101.4	2/25/2120
22325+64	2,666	18	0.246	52,000	1.295	0.059	101.5	4/29/2120
23925+58	2,574	18	0.256	52,000	0.942	0.046	101.6	5/11/2120
23956+01	2,564	18	0.256	52,000	1.765	0.033	102.1	11/22/2120
23984+97	2,548	18	0.246	52,000	0.824	0.039	102.1	12/4/2120
22024+89	2,666	18	0.256	52,000	6.002	0.038	102.3	1/29/2121
23996+39	2,544	18	0.256	52,000	0.824	0.046	102.7	6/16/2121
24014+68	2,540	18	0.256	52,000	1.059	0.038	102.9	9/9/2121
23983+43	2,549	18	0.256	52,000	5.061	0.026	103.4	3/8/2122
22128+79	2,653	18	0.246	52,000	1.059	0.059	104.6	5/24/2123
23845+46	2,591	18	0.256	52,000	0.824	0.054	104.7	7/14/2123
22501+97	2,697	18	0.256	52,000	30.011	0.038	104.8	7/29/2123
23670+00	2,649	18	0.256	52,000	1.412	0.046	104.8	8/4/2123
22818+99	2,654	18	0.256	52,000	2.471	0.054	105.2	12/19/2123
22733+22	2,705	18	0.246	52,000	1.059	0.071	105.5	4/26/2124
22049+12	2,661	18	0.246	52,000	1.177	0.052	106.0	10/2/2124
22109+70	2,663	18	0.256	52,000	1.295	0.059	106.6	6/7/2125
23665+38	2,651	18	0.256	52,000	2.354	0.038	107.0	10/30/2125
22322+80	2,666	18	0.246	52,000	4.472	0.039	107.4	2/26/2126
23994+37	2,545	18	0.256	52,000	3.178	0.026	109.8	8/19/2128

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 6 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22614+77	2,707	18	0.256	52,000	1.765	0.059	110.2	12/31/2128
22820+97	2,658	18	0.256	52,000	1.059	0.079	110.9	9/20/2129
22694+43	2,705	18	0.256	52,000	2.236	0.054	111.2	12/20/2129
23076+67	2,661	18	0.246	52,000	4.590	0.039	111.7	7/4/2130
24035+87	2,533	18	0.256	52,000	2.236	0.026	112.7	7/5/2131
23561+10	2,730	18	0.256	52,000	1.530	0.046	112.9	9/15/2131
23816+48	2,597	18	0.246	52,000	0.942	0.039	113.8	8/17/2132
22423+10	2,664	18	0.256	52,000	1.530	0.059	113.9	9/20/2132
23385+38	2,796	18	0.256	52,000	1.412	0.054	114.4	3/15/2133
23998+11	2,543	18	0.256	52,000	1.177	0.033	114.4	3/16/2133
23994+88	2,544	18	0.256	52,000	1.177	0.033	114.8	8/11/2133
22502+05	2,698	18	0.256	52,000	14.711	0.038	114.9	9/17/2133
22558+77	2,701	18	0.246	52,000	0.824	0.079	115.0	10/3/2133
22823+25	2,660	18	0.246	52,000	1.059	0.066	115.3	2/12/2134
22899+53	2,626	18	0.246	52,000	0.942	0.071	115.5	4/10/2134
23500+62	2,752	18	0.256	52,000	1.177	0.054	115.6	6/2/2134
24012+23	2,541	18	0.246	52,000	1.177	0.027	116.1	11/10/2134
23539+02	2,763	18	0.256	52,000	0.824	0.067	117.3	2/13/2136
23209+56	2,752	18	0.246	52,000	1.295	0.052	118.2	12/27/2136
22325+61	2,666	18	0.246	52,000	1.059	0.059	118.3	1/26/2137
23024+26	2,672	18	0.256	52,000	1.177	0.067	119.7	6/26/2138
22160+42	2,650	18	0.246	52,000	2.236	0.039	120.5	5/6/2139
22502+27	2,698	18	0.256	52,000	1.765	0.054	121.8	8/16/2140
23534+09	2,774	18	0.256	52,000	1.412	0.046	122.4	3/27/2141
23764+41	2,606	18	0.256	52,000	1.295	0.038	123.1	12/13/2141
23974+41	2,561	18	0.246	52,000	0.824	0.032	123.6	5/14/2142
22018+99	2,669	18	0.246	52,000	1.059	0.047	124.6	6/10/2143
22042+51	2,663	18	0.256	52,000	1.530	0.046	125.1	11/10/2143
23853+47	2,590	18	0.256	52,000	1.412	0.033	125.1	11/12/2143
22567+86	2,703	18	0.246	52,000	1.765	0.047	125.7	7/16/2144

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 7 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22899+42	2,625	18	0.246	52,000	0.942	0.066	126.1	12/11/2144
23845+23	2,591	18	0.256	52,000	1.412	0.033	126.2	1/14/2145
23671+54	2,649	18	0.256	52,000	0.824	0.054	126.3	2/7/2145
22288+85	2,665	18	0.246	52,000	0.824	0.066	126.4	3/17/2145
22009+84	2,675	18	0.246	52,000	3.060	0.032	127.0	10/14/2145
22774+47	2,686	18	0.256	52,000	1.765	0.054	127.1	11/20/2145
23207+54	2,752	18	0.246	52,000	0.824	0.066	127.5	4/7/2146
22403+20	2,661	18	0.256	52,000	2.354	0.046	127.8	7/26/2146
23297+36	2,772	18	0.256	52,000	4.119	0.038	127.8	8/13/2146
23282+94	2,764	18	0.246	52,000	2.118	0.039	128.2	1/8/2147
22959+30	2,632	18	0.246	52,000	1.648	0.047	129.2	12/21/2147
22325+70	2,666	18	0.246	52,000	1.412	0.047	129.2	1/1/2148
22517+70	2,698	18	0.246	52,000	3.060	0.039	129.5	4/24/2148
22141+15	2,638	18	0.256	52,000	1.177	0.054	130.1	11/29/2148
23399+68	2,789	18	0.246	52,000	0.942	0.052	130.5	4/12/2149
23688+18	2,642	18	0.246	52,000	0.942	0.039	130.9	9/6/2149
23120+63	2,706	18	0.256	52,000	0.824	0.079	131.2	12/30/2149
23972+81	2,561	18	0.256	52,000	0.942	0.033	131.9	9/1/2150
22354+33	2,665	18	0.246	52,000	0.942	0.059	131.9	9/6/2150
23535+12	2,773	18	0.256	52,000	2.001	0.038	131.9	9/18/2150
22534+85	2,697	18	0.256	52,000	1.059	0.067	132.8	8/14/2151
22230+54	2,656	18	0.256	52,000	1.765	0.046	133.5	4/10/2152
22494+28	2,696	18	0.246	52,000	2.707	0.039	133.8	8/6/2152
23192+87	2,730	18	0.246	52,000	1.295	0.047	134.9	9/8/2153
23083+10	2,658	18	0.256	52,000	1.412	0.054	135.1	11/27/2153
23263+07	2,730	18	0.246	52,000	1.883	0.039	135.3	1/25/2154
22501+86	2,697	18	0.256	52,000	5.885	0.038	136.2	1/7/2155
23374+93	2,801	18	0.256	52,000	0.824	0.067	136.4	3/21/2155
23816+43	2,597	18	0.246	52,000	0.942	0.032	137.4	4/1/2156
23147+75	2,745	18	0.256	52,000	0.942	0.067	138.2	1/8/2157

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 8 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
23751+36	2,612	18	0.246	52,000	1.648	0.027	138.9	9/28/2157
22958+97	2,632	18	0.246	52,000	1.177	0.052	139.0	11/5/2157
23566+84	2,720	18	0.256	52,000	2.471	0.033	140.5	4/26/2159
23810+20	2,601	18	0.256	52,000	1.177	0.033	142.0	10/25/2160
22274+27	2,674	18	0.256	52,000	1.177	0.054	142.1	11/27/2160
23205+85	2,751	18	0.246	52,000	1.177	0.047	142.4	3/9/2161
23205+84	2,751	18	0.246	52,000	1.177	0.047	142.4	3/10/2161
22665+96	2,712	18	0.246	52,000	1.177	0.052	143.0	10/18/2161
23525+11	2,770	18	0.246	52,000	0.824	0.047	143.0	10/23/2161
22879+76	2,617	18	0.246	52,000	1.412	0.047	143.1	12/1/2161
23207+49	2,752	18	0.246	52,000	0.824	0.059	143.9	9/3/2162
23463+42	2,785	18	0.246	52,000	2.118	0.032	144.7	7/1/2163
23471+39	2,778	18	0.246	52,000	1.177	0.039	145.4	3/10/2164
22733+18	2,705	18	0.246	52,000	1.412	0.047	145.5	4/29/2164
23085+40	2,660	18	0.256	52,000	1.059	0.059	148.2	1/19/2167
23827+03	2,591	18	0.256	52,000	0.824	0.038	148.3	2/6/2167
23276+79	2,750	18	0.256	52,000	1.059	0.054	148.6	5/14/2167
22995+61	2,688	18	0.246	52,000	1.059	0.052	149.0	10/9/2167
22114+87	2,663	18	0.256	52,000	2.001	0.038	149.6	5/12/2168
22551+84	2,700	18	0.256	52,000	1.295	0.054	149.7	6/27/2168
23733+39	2,625	18	0.246	52,000	0.942	0.032	150.6	5/20/2169
23241+44	2,752	18	0.246	52,000	1.530	0.039	150.9	9/19/2169
23574+64	2,712	18	0.256	52,000	1.295	0.038	150.9	9/21/2169
23406+31	2,782	18	0.246	52,000	2.118	0.032	151.6	5/25/2170
22865+78	2,601	18	0.256	52,000	1.295	0.054	151.9	9/5/2170
23322+88	2,805	18	0.256	52,000	2.236	0.038	152.5	4/15/2171
23458+97	2,781	18	0.256	52,000	2.707	0.033	153.4	3/8/2172
22704+04	2,699	18	0.256	52,000	1.883	0.046	153.4	3/13/2172
23691+23	2,641	18	0.256	52,000	1.295	0.033	154.7	6/29/2173
23607+01	2,673	18	0.246	52,000	0.824	0.039	155.0	10/12/2173

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 9 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
23751+36	2,612	18	0.246	52,000	1.648	0.027	138.9	9/28/2157
22958+97	2,632	18	0.246	52,000	1.177	0.052	139.0	11/5/2157
23566+84	2,720	18	0.256	52,000	2.471	0.033	140.5	4/26/2159
23810+20	2,601	18	0.256	52,000	1.177	0.033	142.0	10/25/2160
22274+27	2,674	18	0.256	52,000	1.177	0.054	142.1	11/27/2160
23205+85	2,751	18	0.246	52,000	1.177	0.047	142.4	3/9/2161
23205+84	2,751	18	0.246	52,000	1.177	0.047	142.4	3/10/2161
22665+96	2,712	18	0.246	52,000	1.177	0.052	143.0	10/18/2161
23525+11	2,770	18	0.246	52,000	0.824	0.047	143.0	10/23/2161
22879+76	2,617	18	0.246	52,000	1.412	0.047	143.1	12/1/2161
23207+49	2,752	18	0.246	52,000	0.824	0.059	143.9	9/3/2162
23463+42	2,785	18	0.246	52,000	2.118	0.032	144.7	7/1/2163
23471+39	2,778	18	0.246	52,000	1.177	0.039	145.4	3/10/2164
22733+18	2,705	18	0.246	52,000	1.412	0.047	145.5	4/29/2164
23085+40	2,660	18	0.256	52,000	1.059	0.059	148.2	1/19/2167
23827+03	2,591	18	0.256	52,000	0.824	0.038	148.3	2/6/2167
23276+79	2,750	18	0.256	52,000	1.059	0.054	148.6	5/14/2167
22995+61	2,688	18	0.246	52,000	1.059	0.052	149.0	10/9/2167
22114+87	2,663	18	0.256	52,000	2.001	0.038	149.6	5/12/2168
22551+84	2,700	18	0.256	52,000	1.295	0.054	149.7	6/27/2168
23733+39	2,625	18	0.246	52,000	0.942	0.032	150.6	5/20/2169
23241+44	2,752	18	0.246	52,000	1.530	0.039	150.9	9/19/2169
23574+64	2,712	18	0.256	52,000	1.295	0.038	150.9	9/21/2169
23406+31	2,782	18	0.246	52,000	2.118	0.032	151.6	5/25/2170
22865+78	2,601	18	0.256	52,000	1.295	0.054	151.9	9/5/2170
23322+88	2,805	18	0.256	52,000	2.236	0.038	152.5	4/15/2171
23458+97	2,781	18	0.256	52,000	2.707	0.033	153.4	3/8/2172
22704+04	2,699	18	0.256	52,000	1.883	0.046	153.4	3/13/2172
23691+23	2,641	18	0.256	52,000	1.295	0.033	154.7	6/29/2173
23607+01	2,673	18	0.246	52,000	0.824	0.039	155.0	10/12/2173

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 10 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22181+97	2,661	18	0.256	52,000	0.824	0.054	174.9	9/22/2193
23214+03	2,754	18	0.246	52,000	1.177	0.039	174.9	10/1/2193
22209+96	2,656	18	0.256	52,000	1.059	0.046	175.3	2/17/2194
22776+27	2,685	18	0.256	52,000	0.942	0.059	175.5	4/29/2194
22331+50	2,664	18	0.256	52,000	1.177	0.046	176.1	11/24/2194
23300+37	2,775	18	0.256	52,000	1.530	0.038	178.2	1/11/2197
22504+99	2,698	18	0.246	52,000	0.942	0.047	180.0	10/27/2198
23752+28	2,611	18	0.256	52,000	1.295	0.026	183.1	12/6/2201
23241+44	2,752	18	0.246	52,000	3.531	0.027	184.5	4/24/2203
23665+86	2,651	18	0.256	52,000	0.942	0.033	185.3	1/27/2204
22624+51	2,709	18	0.246	52,000	0.942	0.047	185.6	5/30/2204
22289+91	2,664	18	0.256	52,000	2.471	0.033	186.5	5/3/2205
23021+92	2,671	18	0.256	52,000	3.413	0.033	187.3	2/16/2206
23133+69	2,728	18	0.246	52,000	0.824	0.047	188.5	4/10/2207
23149+72	2,747	18	0.256	52,000	1.648	0.038	188.6	5/20/2207
22076+71	2,659	18	0.256	52,000	0.824	0.046	188.8	8/4/2207
23646+44	2,661	18	0.256	52,000	0.942	0.033	189.1	11/29/2207
22718+16	2,699	18	0.246	52,000	7.297	0.027	192.1	12/13/2210
22390+27	2,657	18	0.256	52,000	1.059	0.046	193.3	1/31/2212
22359+00	2,665	18	0.246	52,000	1.648	0.032	194.1	11/30/2212
23560+82	2,731	18	0.256	52,000	0.824	0.038	197.7	7/17/2216
23527+39	2,773	18	0.256	52,000	2.354	0.026	197.9	9/18/2216
23671+40	2,649	18	0.256	52,000	0.824	0.033	198.4	3/11/2217
22460+43	2,674	18	0.256	52,000	1.059	0.046	199.0	10/8/2217
22007+62	2,676	18	0.256	52,000	1.177	0.033	199.5	4/25/2218
22632+54	2,710	18	0.256	52,000	3.060	0.033	200.0	10/11/2218
22537+80	2,698	18	0.256	52,000	1.059	0.046	204.3	2/20/2223
23432+96	2,771	18	0.256	52,000	2.942	0.026	204.4	3/27/2223
23344+92	2,815	18	0.256	52,000	0.824	0.046	204.5	4/3/2223
23426+99	2,761	18	0.256	52,000	2.942	0.026	204.9	9/8/2223

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 11 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22718+18	2,699	18	0.246	52,000	1.883	0.032	204.9	9/28/2223
23157+46	2,752	18	0.246	52,000	0.942	0.039	205.4	3/3/2224
22905+54	2,645	18	0.256	52,000	1.059	0.046	207.5	5/5/2226
22232+43	2,658	18	0.246	52,000	1.177	0.032	207.6	5/23/2226
22325+72	2,666	18	0.246	52,000	1.295	0.032	209.9	9/19/2228
23485+80	2,751	18	0.246	52,000	0.824	0.032	210.0	10/3/2228
23551+00	2,748	18	0.256	52,000	0.942	0.033	210.4	3/22/2229
22694+40	2,705	18	0.256	52,000	1.059	0.046	210.7	6/16/2229
22659+80	2,713	18	0.256	52,000	1.530	0.038	213.4	3/21/2232
22928+97	2,678	18	0.246	52,000	3.178	0.027	214.8	8/10/2233
22965+56	2,629	18	0.256	52,000	1.412	0.038	215.1	12/4/2233
22560+99	2,701	18	0.246	52,000	1.530	0.032	215.3	2/2/2234
22041+78	2,663	18	0.246	52,000	0.824	0.032	216.2	12/27/2234
22746+56	2,703	18	0.246	52,000	3.413	0.027	216.5	4/29/2235
23229+84	2,756	18	0.256	52,000	0.824	0.046	216.9	9/16/2235
22050+86	2,661	18	0.246	52,000	0.824	0.032	217.8	8/17/2236
23014+75	2,691	18	0.256	52,000	0.942	0.046	218.4	3/17/2237
22501+91	2,697	18	0.256	52,000	2.001	0.033	218.8	8/20/2237
23009+93	2,701	18	0.256	52,000	2.001	0.033	219.3	1/26/2238
22999+90	2,692	18	0.256	52,000	0.942	0.046	219.5	4/27/2238
22559+31	2,701	18	0.246	52,000	0.942	0.039	221.1	11/18/2239
22939+60	2,645	18	0.246	52,000	1.412	0.032	222.1	11/15/2240
23228+97	2,755	18	0.256	52,000	1.059	0.038	222.8	8/17/2241
22820+12	2,656	18	0.256	52,000	2.118	0.033	223.2	12/15/2241
23558+58	2,737	18	0.256	52,000	0.824	0.033	224.3	2/16/2243
22443+11	2,673	18	0.246	52,000	1.295	0.027	225.2	1/11/2244
22459+30	2,673	18	0.256	52,000	1.530	0.033	225.2	1/11/2244
23374+45	2,802	18	0.256	52,000	0.942	0.026	225.2	1/11/2244
23347+09	2,814	18	0.256	52,000	0.824	0.033	225.2	1/11/2244
23347+11	2,814	18	0.256	52,000	0.824	0.038	225.2	1/11/2244

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 12 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
23293+75	2,769	18	0.256	52,000	0.824	0.026	225.2	1/11/2244
23283+57	2,765	18	0.246	52,000	0.824	0.027	225.2	1/11/2244
22501+88	2,697	18	0.256	52,000	2.707	0.026	225.2	1/11/2244
22517+79	2,698	18	0.246	52,000	0.824	0.039	225.2	1/11/2244
22537+10	2,698	18	0.256	52,000	1.295	0.033	225.2	1/11/2244
22537+48	2,698	18	0.256	52,000	0.942	0.033	225.2	1/11/2244
22553+38	2,700	18	0.246	52,000	0.824	0.032	225.2	1/11/2244
22571+03	2,703	18	0.256	52,000	0.942	0.038	225.2	1/11/2244
22571+05	2,703	18	0.256	52,000	2.118	0.026	225.2	1/11/2244
22571+01	2,703	18	0.256	52,000	0.942	0.038	225.2	1/11/2244
22578+24	2,704	18	0.256	52,000	0.942	0.038	225.2	1/11/2244
22572+81	2,703	18	0.246	52,000	1.177	0.027	225.2	1/11/2244
22012+27	2,674	18	0.256	52,000	0.824	0.033	225.2	1/11/2244
22600+57	2,705	18	0.256	52,000	0.824	0.046	225.2	1/11/2244
22614+77	2,707	18	0.256	52,000	1.648	0.026	225.2	1/11/2244
22638+28	2,711	18	0.256	52,000	1.295	0.038	225.2	1/11/2244
22648+82	2,711	18	0.256	52,000	1.059	0.038	225.2	1/11/2244
22656+82	2,713	18	0.256	52,000	1.177	0.026	225.2	1/11/2244
22667+16	2,712	18	0.256	52,000	0.942	0.026	225.2	1/11/2244
22074+67	2,659	18	0.256	52,000	0.942	0.033	225.2	1/11/2244
22673+63	2,712	18	0.256	52,000	0.824	0.026	225.2	1/11/2244
22708+87	2,691	18	0.256	52,000	1.883	0.033	225.2	1/11/2244
22708+93	2,691	18	0.256	52,000	2.942	0.026	225.2	1/11/2244
22716+78	2,697	18	0.246	52,000	1.412	0.027	225.2	1/11/2244
22719+49	2,700	18	0.246	52,000	1.295	0.032	225.2	1/11/2244
22105+91	2,663	18	0.256	52,000	2.001	0.026	225.2	1/11/2244
22117+92	2,662	18	0.256	52,000	1.059	0.033	225.2	1/11/2244
22122+41	2,661	18	0.256	52,000	2.118	0.026	225.2	1/11/2244
22750+92	2,702	18	0.246	52,000	0.824	0.027	225.2	1/11/2244
22777+42	2,684	18	0.246	52,000	0.942	0.027	225.2	1/11/2244

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 13 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22131+45	2,650	18	0.256	52,000	0.824	0.026	225.2	1/11/2244
22135+39	2,646	18	0.256	52,000	0.824	0.038	225.2	1/11/2244
22807+07	2,659	18	0.246	52,000	1.412	0.027	225.2	1/11/2244
22825+21	2,663	18	0.256	52,000	0.824	0.033	225.2	1/11/2244
22822+16	2,659	18	0.246	52,000	1.059	0.032	225.2	1/11/2244
22831+45	2,659	18	0.246	52,000	2.236	0.027	225.2	1/11/2244
22847+46	2,624	18	0.256	52,000	1.295	0.026	225.2	1/11/2244
22807+79	2,654	18	0.246	52,000	0.824	0.039	225.2	1/11/2244
22858+68	2,607	18	0.256	52,000	0.824	0.038	225.2	1/11/2244
22899+31	2,625	18	0.246	52,000	0.824	0.032	225.2	1/11/2244
22928+41	2,680	18	0.256	52,000	0.942	0.038	225.2	1/11/2244
22928+95	2,678	18	0.246	52,000	1.295	0.032	225.2	1/11/2244
22911+56	2,662	18	0.256	52,000	0.824	0.026	225.2	1/11/2244
22954+89	2,631	18	0.256	52,000	1.412	0.026	225.2	1/11/2244
22944+89	2,629	18	0.246	52,000	0.942	0.027	225.2	1/11/2244
23031+39	2,644	18	0.246	52,000	1.059	0.027	225.2	1/11/2244
23009+91	2,702	18	0.256	52,000	4.001	0.026	225.2	1/11/2244
23095+91	2,683	18	0.256	52,000	0.942	0.033	225.2	1/11/2244
23110+86	2,694	18	0.256	52,000	1.059	0.038	225.2	1/11/2244
23112+12	2,697	18	0.256	52,000	0.824	0.038	225.2	1/11/2244
23137+69	2,733	18	0.256	52,000	0.824	0.046	225.2	1/11/2244
23179+91	2,737	18	0.246	52,000	1.059	0.027	225.2	1/11/2244
23259+98	2,729	18	0.256	52,000	1.177	0.033	225.2	1/11/2244
23192+17	2,728	18	0.246	52,000	1.059	0.032	225.2	1/11/2244
23222+48	2,755	18	0.246	52,000	0.824	0.032	225.2	1/11/2244
23647+45	2,661	18	0.256	52,000	0.824	0.026	225.2	1/11/2244
22303+97	2,661	18	0.256	52,000	1.059	0.038	225.2	1/11/2244
22325+74	2,666	18	0.246	52,000	0.824	0.032	225.2	1/11/2244
22325+78	2,666	18	0.246	52,000	1.177	0.027	225.2	1/11/2244
22338+31	2,661	18	0.256	52,000	1.765	0.026	225.2	1/11/2244

Table E-1 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Crane to Texon – ILI Date October 19, 2018 (pg. 14 of 14)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
22389+15	2,657	18	0.256	52,000	1.059	0.033	225.2	1/11/2244
22389+15	2,657	18	0.256	52,000	0.942	0.026	225.2	1/11/2244
22405+91	2,661	18	0.256	52,000	0.824	0.038	225.2	1/11/2244
22402+16	2,661	18	0.256	52,000	0.824	0.046	225.2	1/11/2244
22410+69	2,661	18	0.246	52,000	0.824	0.039	225.2	1/11/2244
23461+94	2,784	18	0.256	52,000	1.412	0.026	225.2	1/11/2244
23448+55	2,776	18	0.256	52,000	1.177	0.026	225.2	1/11/2244

Table E-2. Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 1 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1679+53	116	20	0.305	35,000	5.079	0.079	64.6	4/3/2084
1598+51	111	20	0.315	35,000	2.953	0.104	71.0	7/29/2090
1752+00	123	20	0.295	35,000	5.315	0.065	72.1	10/7/2091
1729+58	119	20	0.305	35,000	2.835	0.085	73.4	1/8/2093
1643+16	111	20	0.305	35,000	2.244	0.092	88.5	2/4/2108
1632+14	112	20	0.305	35,000	4.370	0.073	89.9	7/7/2109
1485+41	105	20	0.305	35,000	2.717	0.092	100.0	8/1/2119
1711+20	117	20	0.295	35,000	2.244	0.071	102.7	4/30/2122
1771+12	121	20	0.305	35,000	2.008	0.073	112.7	5/7/2132
1675+02	116	20	0.305	35,000	5.551	0.058	119.9	7/4/2139
1684+38	116	20	0.305	35,000	2.480	0.067	130.2	11/14/2149
1653+96	112	20	0.305	35,000	4.252	0.058	135.5	2/16/2155
939+66	67	20	0.315	35,000	5.197	0.110	139.1	9/4/2158
1471+69	105	20	0.315	35,000	2.598	0.085	145.7	4/13/2165
1653+52	112	20	0.305	35,000	3.071	0.058	154.5	2/15/2174
1684+70	116	20	0.305	35,000	2.717	0.058	154.8	6/17/2174
1477+77	106	20	0.315	35,000	2.008	0.091	156.6	3/24/2176
1618+48	113	20	0.305	35,000	1.535	0.079	158.7	4/13/2178
1745+85	121	20	0.305	35,000	2.835	0.052	161.0	9/2/2180
1695+61	115	20	0.305	35,000	1.417	0.073	164.0	8/21/2183
1723+67	119	20	0.295	35,000	1.535	0.059	165.9	7/13/2185
1632+04	112	20	0.305	35,000	1.890	0.067	167.7	5/15/2187
1658+61	114	20	0.315	35,000	1.890	0.072	168.5	2/23/2188
1709+88	117	20	0.295	35,000	2.717	0.047	172.9	7/16/2192
1654+28	113	20	0.305	35,000	1.654	0.067	176.1	9/20/2195
1712+44	117	20	0.305	35,000	2.598	0.052	176.4	1/24/2196
1728+75	118	20	0.295	35,000	7.795	0.038	178.1	9/15/2197
982+92	70	20	0.305	35,000	3.307	0.104	179.9	7/10/2199
1239+99	87	20	0.305	35,000	2.835	0.085	181.3	12/18/2200
1696+43	116	20	0.315	35,000	1.772	0.066	185.2	10/12/2204

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 2 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1717+61	118	20	0.305	35,000	1.299	0.067	187.3	11/18/2206
1401+21	99	20	0.315	35,000	1.890	0.091	190.1	9/7/2209
1657+46	113	20	0.305	35,000	2.717	0.052	190.2	11/12/2209
1483+02	106	20	0.315	35,000	2.480	0.072	193.8	6/16/2213
1203+57	87	20	0.295	35,000	1.654	0.097	204.9	7/15/2224
1256+98	89	20	0.305	35,000	1.299	0.119	204.9	7/27/2224
1483+79	106	20	0.315	35,000	4.016	0.060	205.7	4/20/2225
1544+58	109	20	0.305	35,000	2.362	0.058	211.7	4/18/2231
1731+29	118	20	0.305	35,000	1.654	0.052	211.7	5/13/2231
1736+11	120	20	0.305	35,000	3.780	0.040	214.8	5/30/2234
1301+14	88	20	0.305	35,000	2.717	0.073	216.9	7/17/2236
1674+30	115	20	0.305	35,000	1.890	0.052	217.7	4/23/2237
1713+88	117	20	0.305	35,000	1.654	0.052	217.8	6/8/2237
1551+52	108	20	0.305	35,000	1.535	0.067	221.6	3/26/2241
1717+71	118	20	0.305	35,000	0.827	0.040	225.2	11/7/2244
1442+68	103	20	0.315	35,000	1.063	0.047	225.2	11/7/2244
1006+86	70	20	0.295	35,000	5.197	0.047	225.2	11/7/2244
995+31	70	20	0.305	35,000	1.063	0.040	225.2	11/7/2244
771+89	65	20	0.305	35,000	4.488	0.040	225.2	11/7/2244
760+49	62	20	0.315	35,000	6.969	0.060	225.2	11/7/2244
760+10	62	20	0.305	35,000	2.953	0.052	225.2	11/7/2244
881+98	60	20	0.305	35,000	0.945	0.052	225.2	11/7/2244
881+98	60	20	0.305	35,000	2.244	0.104	225.2	11/7/2244
991+37	71	20	0.305	35,000	1.063	0.034	225.2	11/7/2244
985+35	71	20	0.305	35,000	4.134	0.073	225.2	11/7/2244
1598+97	111	20	0.315	35,000	1.181	0.038	225.2	11/7/2244
1713+49	117	20	0.295	35,000	1.181	0.038	225.2	11/7/2244
674+77	53	20	0.305	35,000	2.008	0.034	225.2	11/7/2244
673+91	52	20	0.315	35,000	1.063	0.032	225.2	11/7/2244
762+34	63	20	0.315	35,000	1.772	0.085	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 3 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1713+79	117	20	0.305	35,000	1.299	0.034	225.2	11/7/2244
1705+62	116	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
514+07	41	20	0.315	35,000	2.126	0.025	225.2	11/7/2244
991+55	70	20	0.305	35,000	0.827	0.034	225.2	11/7/2244
1581+56	109	20	0.305	35,000	0.945	0.027	225.2	11/7/2244
1697+43	117	20	0.315	35,000	1.063	0.066	225.2	11/7/2244
1422+10	98	20	0.315	35,000	1.063	0.038	225.2	11/7/2244
879+97	60	20	0.295	35,000	0.827	0.038	225.2	11/7/2244
879+98	60	20	0.295	35,000	2.953	0.027	225.2	11/7/2244
875+34	61	20	0.315	35,000	1.063	0.038	225.2	11/7/2244
870+10	61	20	0.295	35,000	2.953	0.038	225.2	11/7/2244
665+38	52	20	0.295	35,000	0.827	0.038	225.2	11/7/2244
665+51	52	20	0.295	35,000	1.417	0.059	225.2	11/7/2244
508+18	41	20	0.295	35,000	2.244	0.065	225.2	11/7/2244
1320+67	88	20	0.295	35,000	2.008	0.059	225.2	11/7/2244
1207+92	87	20	0.305	35,000	0.827	0.046	225.2	11/7/2244
1207+91	87	20	0.305	35,000	1.181	0.058	225.2	11/7/2244
1096+91	79	20	0.295	35,000	1.772	0.047	225.2	11/7/2244
987+52	70	20	0.315	35,000	0.945	0.066	225.2	11/7/2244
973+78	69	20	0.315	35,000	1.063	0.066	225.2	11/7/2244
965+41	69	20	0.295	35,000	1.181	0.091	225.2	11/7/2244
856+11	59	20	0.305	35,000	2.953	0.040	225.2	11/7/2244
1680+35	116	20	0.315	35,000	1.890	0.032	225.2	11/7/2244
1678+02	116	20	0.315	35,000	1.535	0.060	225.2	11/7/2244
509+33	42	20	0.295	35,000	1.654	0.065	225.2	11/7/2244
1098+95	79	20	0.295	35,000	1.654	0.032	225.2	11/7/2244
977+81	70	20	0.305	35,000	1.299	0.040	225.2	11/7/2244
977+10	70	20	0.315	35,000	1.654	0.025	225.2	11/7/2244
971+31	69	20	0.295	35,000	1.063	0.032	225.2	11/7/2244
970+12	69	20	0.305	35,000	1.063	0.027	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 4 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
965+29	69	20	0.295	35,000	1.299	0.038	225.2	11/7/2244
865+86	60	20	0.295	35,000	2.480	0.038	225.2	11/7/2244
853+44	59	20	0.305	35,000	2.126	0.027	225.2	11/7/2244
1692+74	117	20	0.295	35,000	4.843	0.027	225.2	11/7/2244
1687+28	117	20	0.305	35,000	1.417	0.052	225.2	11/7/2244
1684+70	116	20	0.305	35,000	1.181	0.046	225.2	11/7/2244
1193+79	87	20	0.305	35,000	1.063	0.040	225.2	11/7/2244
1193+78	87	20	0.305	35,000	1.535	0.073	225.2	11/7/2244
1097+94	79	20	0.295	35,000	1.417	0.065	225.2	11/7/2244
1097+89	79	20	0.295	35,000	3.543	0.047	225.2	11/7/2244
1097+90	79	20	0.295	35,000	4.370	0.059	225.2	11/7/2244
505+07	41	20	0.305	35,000	5.197	0.052	225.2	11/7/2244
501+75	40	20	0.315	35,000	1.063	0.038	225.2	11/7/2244
1407+41	99	20	0.315	35,000	0.945	0.032	225.2	11/7/2244
1403+90	100	20	0.305	35,000	1.417	0.052	225.2	11/7/2244
1188+37	87	20	0.295	35,000	0.827	0.027	225.2	11/7/2244
1556+18	107	20	0.315	35,000	3.425	0.025	225.2	11/7/2244
1551+35	108	20	0.305	35,000	1.063	0.027	225.2	11/7/2244
1551+32	108	20	0.305	35,000	1.535	0.052	225.2	11/7/2244
1548+94	110	20	0.305	35,000	0.827	0.027	225.2	11/7/2244
1548+95	110	20	0.305	35,000	1.417	0.052	225.2	11/7/2244
961+67	68	20	0.295	35,000	3.189	0.059	225.2	11/7/2244
957+06	68	20	0.305	35,000	1.417	0.027	225.2	11/7/2244
957+07	68	20	0.305	35,000	2.126	0.040	225.2	11/7/2244
1400+92	99	20	0.315	35,000	1.063	0.079	225.2	11/7/2244
1400+93	99	20	0.315	35,000	1.890	0.047	225.2	11/7/2244
856+86	59	20	0.305	35,000	2.008	0.052	225.2	11/7/2244
849+57	62	20	0.305	35,000	0.827	0.034	225.2	11/7/2244
849+64	62	20	0.305	35,000	2.362	0.067	225.2	11/7/2244
845+45	58	20	0.315	35,000	0.945	0.066	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 5 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
500+71	40	20	0.315	35,000	1.299	0.072	225.2	11/7/2244
494+73	41	20	0.305	35,000	1.299	0.027	225.2	11/7/2244
1666+35	114	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
1545+07	109	20	0.295	35,000	1.299	0.027	225.2	11/7/2244
1089+28	79	20	0.295	35,000	1.063	0.027	225.2	11/7/2244
1396+18	99	20	0.315	35,000	1.417	0.025	225.2	11/7/2244
965+75	68	20	0.305	35,000	3.543	0.052	225.2	11/7/2244
965+55	68	20	0.305	35,000	3.543	0.058	225.2	11/7/2244
952+21	68	20	0.295	35,000	2.244	0.032	225.2	11/7/2244
1666+98	115	20	0.325	35,000	1.063	0.085	225.2	11/7/2244
853+17	59	20	0.305	35,000	2.244	0.067	225.2	11/7/2244
853+16	59	20	0.305	35,000	7.559	0.067	225.2	11/7/2244
849+49	62	20	0.305	35,000	1.063	0.040	225.2	11/7/2244
849+48	62	20	0.305	35,000	1.063	0.034	225.2	11/7/2244
1187+19	86	20	0.305	35,000	3.189	0.027	225.2	11/7/2244
1187+21	86	20	0.305	35,000	6.260	0.040	225.2	11/7/2244
1549+78	109	20	0.305	35,000	1.181	0.027	225.2	11/7/2244
493+73	40	20	0.315	35,000	1.654	0.025	225.2	11/7/2244
746+69	59	20	0.305	35,000	1.063	0.034	225.2	11/7/2244
742+35	57	20	0.305	35,000	7.087	0.079	225.2	11/7/2244
732+71	57	20	0.305	35,000	1.181	0.058	225.2	11/7/2244
1654+27	113	20	0.305	35,000	1.063	0.027	225.2	11/7/2244
1289+55	87	20	0.305	35,000	2.008	0.058	225.2	11/7/2244
947+16	67	20	0.305	35,000	1.299	0.027	225.2	11/7/2244
947+16	67	20	0.305	35,000	2.480	0.027	225.2	11/7/2244
1541+21	108	20	0.305	35,000	1.181	0.058	225.2	11/7/2244
1776+39	123	20	0.305	35,000	1.417	0.034	225.2	11/7/2244
1775+82	123	20	0.305	35,000	1.063	0.058	225.2	11/7/2244
1089+63	79	20	0.305	35,000	6.496	0.067	225.2	11/7/2244
736+10	53	20	0.305	35,000	2.008	0.067	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 6 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
732+33	57	20	0.305	35,000	1.299	0.027	225.2	11/7/2244
732+34	57	20	0.305	35,000	1.772	0.034	225.2	11/7/2244
945+55	68	20	0.305	35,000	7.559	0.058	225.2	11/7/2244
1077+56	77	20	0.305	35,000	1.063	0.027	225.2	11/7/2244
1525+59	106	20	0.315	35,000	2.126	0.032	225.2	11/7/2244
735+28	53	20	0.305	35,000	1.063	0.046	225.2	11/7/2244
733+74	57	20	0.295	35,000	1.063	0.038	225.2	11/7/2244
940+60	67	20	0.305	35,000	1.299	0.058	225.2	11/7/2244
940+03	67	20	0.315	35,000	0.827	0.025	225.2	11/7/2244
939+95	67	20	0.315	35,000	0.945	0.032	225.2	11/7/2244
939+67	67	20	0.315	35,000	3.189	0.104	225.2	11/7/2244
937+83	67	20	0.315	35,000	0.945	0.032	225.2	11/7/2244
1657+39	113	20	0.305	35,000	2.480	0.040	225.2	11/7/2244
1649+14	112	20	0.305	35,000	0.827	0.027	225.2	11/7/2244
646+07	50	20	0.315	35,000	1.890	0.054	225.2	11/7/2244
836+54	58	20	0.315	35,000	2.244	0.047	225.2	11/7/2244
1292+79	87	20	0.305	35,000	2.480	0.034	225.2	11/7/2244
1523+47	107	20	0.305	35,000	1.654	0.034	225.2	11/7/2244
1520+37	107	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
1513+21	107	20	0.315	35,000	1.299	0.038	225.2	11/7/2244
939+85	67	20	0.315	35,000	1.181	0.047	225.2	11/7/2244
939+85	67	20	0.315	35,000	3.898	0.047	225.2	11/7/2244
735+78	56	20	0.315	35,000	1.181	0.038	225.2	11/7/2244
1512+75	106	20	0.315	35,000	2.126	0.060	225.2	11/7/2244
1512+49	106	20	0.305	35,000	1.299	0.046	225.2	11/7/2244
1512+30	106	20	0.305	35,000	2.244	0.040	225.2	11/7/2244
1510+93	107	20	0.315	35,000	2.008	0.060	225.2	11/7/2244
1510+84	107	20	0.315	35,000	3.425	0.032	225.2	11/7/2244
1499+60	106	20	0.295	35,000	0.945	0.047	225.2	11/7/2244
832+63	57	20	0.315	35,000	1.535	0.038	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 7 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
832+86	57	20	0.315	35,000	4.134	0.054	225.2	11/7/2244
1168+59	85	20	0.295	35,000	1.299	0.032	225.2	11/7/2244
1516+22	107	20	0.305	35,000	1.890	0.052	225.2	11/7/2244
1509+45	107	20	0.305	35,000	4.606	0.027	225.2	11/7/2244
1499+41	106	20	0.295	35,000	1.181	0.032	225.2	11/7/2244
573+12	43	20	0.315	35,000	1.063	0.038	225.2	11/7/2244
568+21	43	20	0.315	35,000	1.063	0.032	225.2	11/7/2244
568+22	43	20	0.315	35,000	2.480	0.047	225.2	11/7/2244
564+86	43	20	0.305	35,000	1.417	0.034	225.2	11/7/2244
1075+65	77	20	0.305	35,000	2.480	0.085	225.2	11/7/2244
1062+00	75	20	0.305	35,000	1.299	0.092	225.2	11/7/2244
843+94	59	20	0.305	35,000	1.063	0.034	225.2	11/7/2244
648+16	51	20	0.315	35,000	1.181	0.038	225.2	11/7/2244
643+60	50	20	0.315	35,000	0.827	0.032	225.2	11/7/2244
641+90	50	20	0.315	35,000	1.890	0.025	225.2	11/7/2244
1501+73	107	20	0.295	35,000	1.063	0.032	225.2	11/7/2244
1501+72	107	20	0.295	35,000	1.772	0.027	225.2	11/7/2244
1501+47	106	20	0.295	35,000	2.480	0.032	225.2	11/7/2244
1482+04	106	20	0.305	35,000	1.181	0.027	225.2	11/7/2244
929+37	63	20	0.305	35,000	0.827	0.073	225.2	11/7/2244
1641+92	112	20	0.295	35,000	3.543	0.032	225.2	11/7/2244
563+85	43	20	0.305	35,000	0.827	0.058	225.2	11/7/2244
1481+59	106	20	0.315	35,000	2.008	0.060	225.2	11/7/2244
642+16	51	20	0.315	35,000	1.299	0.032	225.2	11/7/2244
928+50	63	20	0.305	35,000	1.417	0.027	225.2	11/7/2244
926+27	62	20	0.305	35,000	1.063	0.052	225.2	11/7/2244
1260+44	87	20	0.295	35,000	11.693	0.027	225.2	11/7/2244
1632+09	112	20	0.305	35,000	1.299	0.052	225.2	11/7/2244
1632+08	112	20	0.305	35,000	1.417	0.046	225.2	11/7/2244
1759+74	124	20	0.305	35,000	2.953	0.034	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 8 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1755+70	123	20	0.295	35,000	1.181	0.027	225.2	11/7/2244
731+22	57	20	0.305	35,000	0.945	0.034	225.2	11/7/2244
1487+92	106	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
1477+96	106	20	0.315	35,000	1.535	0.032	225.2	11/7/2244
1477+86	106	20	0.315	35,000	2.126	0.032	225.2	11/7/2244
1156+67	85	20	0.305	35,000	1.181	0.027	225.2	11/7/2244
1632+12	112	20	0.305	35,000	1.417	0.040	225.2	11/7/2244
563+10	43	20	0.305	35,000	1.299	0.067	225.2	11/7/2244
561+20	43	20	0.315	35,000	2.835	0.047	225.2	11/7/2244
1259+57	88	20	0.305	35,000	1.299	0.034	225.2	11/7/2244
925+91	61	20	0.305	35,000	3.307	0.040	225.2	11/7/2244
1740+10	120	20	0.305	35,000	1.063	0.027	225.2	11/7/2244
1054+82	73	20	0.295	35,000	1.535	0.032	225.2	11/7/2244
1052+80	73	20	0.315	35,000	1.299	0.038	225.2	11/7/2244
1487+09	106	20	0.315	35,000	2.598	0.054	225.2	11/7/2244
1478+69	106	20	0.315	35,000	1.417	0.060	225.2	11/7/2244
1478+76	106	20	0.315	35,000	1.654	0.072	225.2	11/7/2244
1471+72	105	20	0.315	35,000	0.945	0.047	225.2	11/7/2244
1471+75	105	20	0.315	35,000	1.417	0.079	225.2	11/7/2244
1632+14	112	20	0.305	35,000	1.299	0.052	225.2	11/7/2244
1265+49	88	20	0.295	35,000	0.945	0.080	225.2	11/7/2244
1258+58	89	20	0.315	35,000	2.244	0.038	225.2	11/7/2244
817+69	60	20	0.305	35,000	1.417	0.027	225.2	11/7/2244
1374+72	94	20	0.305	35,000	1.417	0.058	225.2	11/7/2244
548+22	42	20	0.315	35,000	2.953	0.091	225.2	11/7/2244
1462+20	105	20	0.305	35,000	1.417	0.040	225.2	11/7/2244
1051+84	73	20	0.295	35,000	2.598	0.032	225.2	11/7/2244
1632+18	112	20	0.305	35,000	1.063	0.067	225.2	11/7/2244
633+06	49	20	0.305	35,000	0.827	0.040	225.2	11/7/2244
1157+16	85	20	0.305	35,000	1.654	0.034	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 9 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1261+03	88	20	0.305	35,000	0.827	0.034	225.2	11/7/2244
1253+10	87	20	0.315	35,000	2.821	0.032	225.2	11/7/2244
1249+21	87	20	0.305	35,000	0.945	0.027	225.2	11/7/2244
1476+08	104	20	0.305	35,000	2.362	0.052	225.2	11/7/2244
1628+50	112	20	0.315	35,000	0.945	0.060	225.2	11/7/2244
1052+39	72	20	0.315	35,000	2.717	0.060	225.2	11/7/2244
1744+30	121	20	0.295	35,000	2.126	0.027	225.2	11/7/2244
554+95	43	20	0.305	35,000	1.417	0.046	225.2	11/7/2244
547+96	42	20	0.305	35,000	1.772	0.052	225.2	11/7/2244
545+20	42	20	0.315	35,000	2.835	0.025	225.2	11/7/2244
1153+65	85	20	0.295	35,000	1.417	0.053	225.2	11/7/2244
1251+54	87	20	0.315	35,000	0.945	0.047	225.2	11/7/2244
636+78	50	20	0.315	35,000	0.827	0.025	225.2	11/7/2244
731+09	57	20	0.315	35,000	0.945	0.054	225.2	11/7/2244
719+27	56	20	0.305	35,000	4.725	0.034	225.2	11/7/2244
1464+95	105	20	0.305	35,000	2.008	0.046	225.2	11/7/2244
1627+77	112	20	0.305	35,000	1.063	0.073	225.2	11/7/2244
811+65	61	20	0.315	35,000	2.126	0.047	225.2	11/7/2244
1729+13	118	20	0.295	35,000	0.827	0.032	225.2	11/7/2244
1729+13	118	20	0.295	35,000	1.299	0.047	225.2	11/7/2244
1251+17	88	20	0.305	35,000	1.181	0.027	225.2	11/7/2244
1248+51	87	20	0.305	35,000	1.772	0.073	225.2	11/7/2244
1741+81	119	20	0.315	35,000	0.945	0.054	225.2	11/7/2244
636+21	49	20	0.315	35,000	2.008	0.079	225.2	11/7/2244
808+97	63	20	0.315	35,000	2.244	0.132	225.2	11/7/2244
808+84	63	20	0.315	35,000	2.362	0.060	225.2	11/7/2244
1041+74	70	20	0.305	35,000	2.717	0.027	225.2	11/7/2244
1151+04	85	20	0.295	35,000	0.945	0.027	225.2	11/7/2244
1256+81	88	20	0.305	35,000	1.535	0.027	225.2	11/7/2244
543+44	41	20	0.315	35,000	1.063	0.038	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 10 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
811+17	61	20	0.315	35,000	1.299	0.047	225.2	11/7/2244
1146+26	83	20	0.315	35,000	1.181	0.054	225.2	11/7/2244
1145+34	83	20	0.315	35,000	0.945	0.038	225.2	11/7/2244
1241+15	87	20	0.305	35,000	1.063	0.040	225.2	11/7/2244
1241+10	87	20	0.305	35,000	1.181	0.046	225.2	11/7/2244
1237+09	86	20	0.305	35,000	0.945	0.052	225.2	11/7/2244
1609+58	111	20	0.305	35,000	1.535	0.052	225.2	11/7/2244
1737+32	119	20	0.295	35,000	1.654	0.032	225.2	11/7/2244
1717+46	118	20	0.305	35,000	1.181	0.046	225.2	11/7/2244
1610+76	112	20	0.305	35,000	0.945	0.058	225.2	11/7/2244
1610+10	112	20	0.305	35,000	2.244	0.040	225.2	11/7/2244
1461+18	105	20	0.305	35,000	3.425	0.040	225.2	11/7/2244
1447+79	105	20	0.315	35,000	6.142	0.054	225.2	11/7/2244
1145+24	83	20	0.315	35,000	2.717	0.054	225.2	11/7/2244
1142+04	84	20	0.315	35,000	1.181	0.054	225.2	11/7/2244
807+14	62	20	0.305	35,000	1.535	0.052	225.2	11/7/2244
796+69	64	20	0.305	35,000	1.417	0.052	225.2	11/7/2244
1029+37	71	20	0.305	35,000	0.827	0.058	225.2	11/7/2244
480+77	39	20	0.305	35,000	1.181	0.027	225.2	11/7/2244
904+20	60	20	0.295	35,000	3.071	0.053	225.2	11/7/2244
798+47	62	20	0.305	35,000	2.244	0.073	225.2	11/7/2244
1447+77	105	20	0.315	35,000	8.268	0.032	225.2	11/7/2244
704+94	54	20	0.315	35,000	1.299	0.066	225.2	11/7/2244
625+80	48	20	0.305	35,000	2.717	0.058	225.2	11/7/2244
625+81	48	20	0.305	35,000	2.953	0.046	225.2	11/7/2244
1239+30	87	20	0.295	35,000	1.299	0.053	225.2	11/7/2244
1227+91	86	20	0.315	35,000	0.827	0.047	225.2	11/7/2244
544+13	40	20	0.315	35,000	3.425	0.072	225.2	11/7/2244
1027+67	70	20	0.295	35,000	2.362	0.053	225.2	11/7/2244
1347+08	87	20	0.305	35,000	4.134	0.058	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 11 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
1013+90	70	20	0.305	35,000	1.063	0.073	225.2	11/7/2244
903+71	61	20	0.305	35,000	1.063	0.046	225.2	11/7/2244
896+23	61	20	0.305	35,000	1.417	0.052	225.2	11/7/2244
1227+08	86	20	0.315	35,000	1.299	0.025	225.2	11/7/2244
1226+82	87	20	0.305	35,000	1.417	0.067	225.2	11/7/2244
796+00	64	20	0.305	35,000	2.362	0.052	225.2	11/7/2244
784+32	64	20	0.315	35,000	2.598	0.047	225.2	11/7/2244
1130+14	82	20	0.305	35,000	3.071	0.027	225.2	11/7/2244
1017+86	70	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
1226+64	87	20	0.305	35,000	0.827	0.027	225.2	11/7/2244
1223+33	87	20	0.305	35,000	0.945	0.067	225.2	11/7/2244
537+82	40	20	0.305	35,000	1.063	0.067	225.2	11/7/2244
785+44	64	20	0.305	35,000	2.953	0.098	225.2	11/7/2244
1013+46	71	20	0.295	35,000	0.945	0.047	225.2	11/7/2244
1012+82	71	20	0.305	35,000	1.772	0.058	225.2	11/7/2244
1126+83	83	20	0.315	35,000	2.717	0.054	225.2	11/7/2244
1121+31	82	20	0.305	35,000	1.535	0.027	225.2	11/7/2244
1121+28	82	20	0.305	35,000	0.945	0.040	225.2	11/7/2244
1011+66	71	20	0.315	35,000	1.654	0.060	225.2	11/7/2244
705+71	54	20	0.295	35,000	1.181	0.032	225.2	11/7/2244
697+57	52	20	0.305	35,000	2.008	0.046	225.2	11/7/2244
792+29	65	20	0.315	35,000	1.417	0.066	225.2	11/7/2244
1008+81	70	20	0.315	35,000	2.717	0.038	225.2	11/7/2244
788+96	65	20	0.305	35,000	3.543	0.058	225.2	11/7/2244
782+10	65	20	0.315	35,000	1.181	0.054	225.2	11/7/2244
525+43	20	20	0.305	35,000	1.654	0.052	225.2	11/7/2244
887+08	60	20	0.295	35,000	8.740	0.059	225.2	11/7/2244
786+87	64	20	0.305	35,000	1.535	0.040	225.2	11/7/2244
886+57	60	20	0.305	35,000	1.417	0.040	225.2	11/7/2244
682+38	53	20	0.305	35,000	4.370	0.067	225.2	11/7/2244

Table E-2 (continued). Pressure-Cycle-Induced Fatigue Cracking Analysis of ILI Indicated Anomalies Satsuma to East Houston – ILI Date August 16, 2019 (pg. 11 of 12)

Station Number	Elevation (feet)	OD (inch)	WT (inch)	YS (psi)	ILI Length (inch)	ILI Depth (inch)	Re-assessment Interval (years)	Re-assessment Due Date
680+89	52	20	0.295	35,000	3.307	0.027	225.2	11/7/2244
680+73	52	20	0.295	35,000	3.780	0.047	225.2	11/7/2244
517+95	40	20	0.315	35,000	2.598	0.054	225.2	11/7/2244
517+73	40	20	0.315	35,000	1.063	0.066	225.2	11/7/2244
517+62	40	20	0.315	35,000	1.299	0.038	225.2	11/7/2244