THE LONGHORN MITIGATION PLAN
(REVISED)

Revised September 29, 2021

TABLE OF CONTENTS

Page No.

1. INTRODUCTION

1.1. An Overview of the Longhorn Commitment

Longhorn Partners Pipeline, L.P. ("Longhorn") was formed in 1995 with the goal of delivering refined petroleum products (gasoline and other motor fuels) to markets in El Paso, with connections through other pipelines to New Mexico and Arizona. The Longhorn Pipeline will create more competitive markets for consumers and will allow these markets to better meet federally mandated air quality standards.

In its operation of the Longhorn Pipeline, Longhorn is committed to protecting human health and safety and the environment. That commitment is reflected in Longhorn's diligent preparation of all components of the Longhorn Pipeline, including both the existing pipeline acquired from Exxon Pipeline Company, traveling from Houston to Crane, Texas, and the new sections of the pipeline extending west to El Paso, north to Midland/Odessa, and south to the Longhorn Pipeline's origin station at the GATX facilities in Galena Park, Texas.

In order to determine the condition of the existing segment of the Longhorn Pipeline, Longhorn conducted thorough hydrostatic pressure tests and internal inspections, employing sophisticated devices designed to confirm the pipeline's wall thickness and other structural conditions. The results were carefully evaluated and repairs were made whenever a conservative evaluation of the data indicated that repairs were called for to ensure that the existing pipeline was safe.

The newly constructed extensions to the Longhorn Pipeline were built to the highest industry standards, and Longhorn scrupulously supervised all aspects of the construction phase and the conduct of hydrostatic pressure tests to ensure the integrity of the new pipeline segments at the conclusion of the construction.

Longhorn has committed to perform a technologically advanced internal inspection at startup of the pipeline system and is committed to perform future internal inspections and tests pursuant to a comprehensive Operational Reliability Assessment (See Section 4). In addition, Longhorn has committed to complete additional refurbishment of the pipeline and to lower the pipeline at numerous locations where analysis has shown a greater risk of third party or other external damage. Longhorn is making extensive commitments to the public and to the Lead Agencies (the "Longhorn Commitment") as set out below to ensure the safe operation of its pipeline. The Longhorn Commitment is expressed in detail in Section 1.2 "The Longhorn Commitment." These expressions of the Longhorn Commitment go well beyond the requirements of law and regulation and the best industry standards. Longhorn is confident that its ongoing commitment to protect the environment, together with the analyses and conclusions associated with the Environmental Assessment, will lead to the operation of the Longhorn Pipeline as one of the premier petroleum pipelines in Texas and in the United States.

The Longhorn Commitment is made in the utmost of good faith. It is one of the products of a process embraced by Longhorn in the interests of human life, health and safety and the environment. Longhorn expects and relies upon the good faith conduct of the other parties to this process in cooperating with Longhorn when Longhorn is required to obtain permits, licenses, and approvals from regulatory authorities or governmental agencies, to implement the Longhorn Mitigation Commitments.

1.2. The Longhorn Commitment

Longhorn's commitment to make its pipeline safe for the environment and the citizens of the State of Texas will include the adoption by Longhorn of the mitigation measures described below which will, in large part, be implemented to address the four leading causes of pipeline failures: (a) Outside Force Damage, (b) Corrosion, (c) Operator Error, and (d) Material Defects. Additionally, a number of the mitigation measures described below are being adopted to ensure that any pipeline leaks are promptly detected and contained ("Leak Detection Control"). Longhorn's Mitigation Commitments described below include many commitments that Longhorn adopted as part of its initial plans to make its pipeline system as safe as possible. Longhorn has decided to adopt a number of the additional Mitigation Commitments described below as part of the valuable "learning process" it has gone through by participating in this Environmental Assessment. Most of the Mitigation Commitments described below go beyond what is required by current law or regulation.

The Mitigation Commitments below show (1) a description of the commitment, (2) the timing of the implementation of the commitment by Longhorn and (3) the nature(s) of the primary risks the commitment is intended to address. The Mitigation Commitments described below are provided in summary form, with references, where appropriate, to attachments or appendices to this Mitigation Commitment for further detailed description.

Longhorn Mitigation Commitments			
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 Item 9.	Prior to startup	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	Outside Force Damage, Material Defects, Corrosion and Previous Defects
3	Longhorn shall replace approximately nineteen 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	Outside Force Damage, Corrosion, Material Defects and Operator Error

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
4	Longhorn shall perform the following additional cathodic protection mitigation work:	Prior to startup	Corrosion
	(a) Install thirteen additional cathodic protection ground beds at the locations described in Mitigation Appendix, Item 4.		
	(b) Perform interference testing at twenty locations, if necessary, as described in Mitigation Appendix, Item 4.		
	(c) Replace at least 600 feet of coating identified by the cathodic protection survey analysis as described in Mitigation Appendix, Item 4.		
	(d) Repair or replace, as necessary, 12 shorted casings identified by the cathodic protection survey analysis at the locations described in Mitigation Appendix, Item 4.		
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	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	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	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	Material Defects, Corrosion and Outside Force Damage

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
9	Longhorn shall remediate any maximum allowable surge pressure 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 maximum allowable surge pressures. The hydrostatic test will requalify the portions of the pipeline which will be tested to a maximum allowable surge pressure 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	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 Operational Reliability Assessment, provided that an inspection shall be performed no more than 3 years after system startup in Tier II and III areas	Material Defects, Corrosion, Outside Force Damage and Previous Defects
11	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a high resolution magnetic flux leakage (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 Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	Within 3 months of startup and thereafter at such intervals as are established by the Operational Reliability Assessment	Corrosion, Outside Force Damage and Previous Defects
12	Longhorn shall, following the use of sizing and (where appropriate) geometry tools, perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with an ultrasonic wall measurement tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 5 years after system startup	Corrosion, Material Defects, Outside Force Damage and Previous Defects

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
12 A	Longhorn shall perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a "smart" geometry inspection tool and remediate any problems identified. See the Longhorn Pipeline System Integrity Plan at Sec. 3.5.2 and the associated Operational Reliability Assessment at Sec. 4.0.	At such intervals as are established by the Operational Reliability Assessment, provided that no more than 3 years shall pass without an in-line inspection being performed using an inspection tool capable of detecting third party damage (e.g. TFI, HRMFL, or geometry)	Outside Force Damage
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 twelve (12) to one hundred twenty (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	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 [MP203.66 – 204.75], 8897+60 – 8945+40 [MP168.52 – 169.42], and 1729+24 – 1734+81 [MP32.75 – 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	Corrosion

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
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 of the pipeline across the Colorado River. See Mitigation Appendix, Item 15.	Prior to startup	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 have been identified in Travis County between Milepost 164 and 168. These and other 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	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
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	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 (See Mitigation Appendix, Item 19):	Prior to startup	Outside Force Damage, Corrosion and Material Defects
	(a) Stress corrosion cracking potential.		Outside Force Damage and Corrosion
	(b) Scour, erosion and flood potential.		Outside Force Damage
	(c) Seismic activity.		Outside Force Damage
	(d) Ground movement, subsidence and aseismic faulting.		Outside Force Damage
	(e) Landslide potential.		Outside Force Damage
	(f) Soil stress.		Outside Force Damage

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
	(g) Root cause analysis on all historical leaks and repairs.		Outside Force Damage, Corrosion, Material Defects, and Operator Error
20	Longhorn shall increase the frequency of patrols in hypersensitive and sensitive areas to every two and one-half days, daily in the Edwards Aquifer area, and weekly in all other areas. See the Longhorn Pipeline System Integrity Plan, Section 3.5.4.	Continuously after startup	Outside Force Damage, Corrosion, Material Defects, Leak Detection and Control
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	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 two 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	Leak Detection and Control
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	Leak Detection and Control

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
25	Longhorn shall develop enhanced public education/damage prevention programs to, inter alia, (a) ensure awareness among contractors and potentially affected public, (b) promote cooperation in protecting the pipeline and (c) to provide information to potentially affected communities with regard to detection of and responses to well water contamination. See the Longhorn Pipeline System Integrity Plan, section 3.5.4. See Mitigation Appendix, Item 25.	Continuously after startup	Outside Force Damage, Leak Detection and Control
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	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	Leak Detection and Control
28	Longhorn shall revise its facility response plan, if necessary, to make it consistent, to the extent practicable, with the City of Austin's Barton Springs oil spill contingency plan and the United States Fish and Wildlife Service's Barton Springs Salamander Recovery Plan. See Mitigation Appendix, Item 28.	Prior to startup or as the referenced plans are developed	Leak Detection and Control
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 Operational Reliability Assessment (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	Leak Detection and Control

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
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 regulations – 49 CFR 195.416), 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 an 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 (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 species 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.	(a) Within 30 days of startup (b) At any time such activity could have an adverse effect on listed species or habitat.	Potential adverse effects to the Barton Springs Salamander Potential adverse effects to listed species or habitat

Longhorn Mitigation Commitments			
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 pressures 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 (MP127.88 – 128.00) and 10489+47 –10490+00 (MP198.66 – 198.67) and (b) installation of pressure activated by-pass systems at the Brazos, Colorado, Pedernales and Llano rivers. In addition, Longhorn shall replace one 671 foot section of pipe (Station Nos. 16992+41 – 16999+12 [MP321.83 – 321.95]) which contains several shorter sections 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 will 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 requirements as supplements to the Environmental Assessment of the Proposed Longhorn Pipeline System. For each such pump station, Longhorn shall submit the site-specific environmental study to the U.S. Department of Transportation no less than 180 days prior to commencement of construction.	Prior to construction of any new pump station	Consistency with the National Environmental Policy Act
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 cleanup 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 relate 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 two (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

Longhorn Mitigation Commitments			
No.	**Description**	**Timing of Implementation**	**Risk(s) Addressed**
39	The Longhorn Mitigation Plan, and associated Pipeline System Integrity Plan and Operational Reliability Assessment, shall not be unilaterally changed. The Longhorn Mitigation Plan 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

Any of the Mitigation Commitments described above which require Longhorn to inspect and evaluate conditions on its pipeline system and then take potential corrective actions such as "remediate", "repair", "lower", etc. shall require Longhorn to make the decisions on potential corrective actions in accordance with best industry standards and in accordance with all applicable laws, rules and regulations (collectively "Highest Standards"). Additionally, any corrective actions taken by Longhorn shall also be in accordance with Highest Standards, whether performed during execution of Longhorn's Mitigation Commitments or performed pursuant to normal operations and maintenance, the Longhorn Pipeline System Integrity Plan, on the Operational Reliability Assessment. Longhorn agrees to provide to DOT/OPS a schedule of all work to be performed by Longhorn in implementing any of its Mitigation Commitments and agrees to promptly notify DOT/OPS of any material changes to any schedules previously furnished. Additionally, Longhorn agrees to provide to DOT/OPS a written report promptly following completion of each Mitigation Commitment setting out in reasonable detail how each Mitigation Commitment has been implemented consistent with Highest Standards. The reports described in this paragraph shall be available to the public.

Several of the Longhorn Mitigation Commitments may lead to the replacement of sections of the existing pipeline. In some cases, Longhorn commits to replace sections of pipe (see e.g., Mitigation Commitment Items 6 and 34), and in other cases a section of pipe may be replaced depending upon the findings of in-the-field investigation and evaluation (see e.g., Mitigation Commitment Items 5, 7 and 18). In cases where the pipe is replaced, with the exception of the replacement over the Edwards Aquifer Recharge Zone, the replacement pipe will be API 5L code pipe (which standard includes considerations of pipe toughness) that will operate at a maximum operating pressure no lesser than the maximum operating pressure established by the most recently performed qualifying hydrostatic pressure test for that pipeline segment. All replacement pipe will be coated with a minimum of 14 mils fusion bonded epoxy (FBE) for corrosion protection. In those cases where streams or roads are encountered or bores are required, additional pipe coating consisting of either 20 mils of abrasion resistant FBE or 1" of concrete coating will be employed. Specifications for the pipe to be replaced over the Edwards Aquifer Recharge Zone are set forth in detail in Mitigation Commitment Item 3.

1.3. Mitigation Appendix

ITEM 1:

WORK SCOPE
HYDROSTATIC TEST
SENSITIVE AND HYPERSENSITIVE AREAS

Scope:

The pipeline system will be hydrostatically tested in sensitive (Tier II) and hypersensitive (Tier III) areas, as those areas are designated in the Environmental Assessment. These sections will be tested to pressures of no less than 90% of specified minimum yield strength (SMYS). In addition, these pressures will achieve levels of no less than 125% of the allowable MOP of the pipe, as demonstrated by the results of the tests.

If segments fail during the test, they will be replaced with new pipe as described in Section 1.2 of this Mitigation Plan.

Sensitive and Hypersensitive Areas to be Hydrostatically Tested

Begin Mile	End Mile	Length (mile)
1.2	1.8	0.60
2.6	3.9	1.30
4.0	6.2	2.20
7.4	7.8	0.40
8.3	10.7	2.40
11.2	26.7	14.50
27.5	36.4	8.90
63.81	64.06	0.25
74.5	75.1	0.60
123.2	123.9	0.70
124.8	125.2	0.40
125.6	150.7	25.10
127.5	128.8	1.30
131.30	131.54	0.24
134.40	134.59	0.29
152.20	155.00	2.60
157.4	157.7	0.30
160.70	161.10	0.40
163.48	177.9	14.42
178.40	179.89	1.49
180.20	180.50	0.30

Begin Mile	End Mile	Length (mile)
180.80	182.80	2.00
184.73	184.86	0.12
185.41	185.79	0.38
187.53	187.65	0.12
189.46	189.58	0.12
190.08	190.20	0.12
190.26	190.39	0.12
191.38	191.44	0.06
192.19	192.25	0.06
192.63	193.43	0.80
192.94	193.30	0.81
193.30	193.43	0.13
193.68	194.18	0.50
194.50	196.10	1.60
196.10	197.00	0.90
197.29	197.53	0.25
198.16	198.28	0.12
198.59	198.96	0.37
199.34	199.46	0.12
201.26	201.39	0.12
201.88	202.13	0.25
202.26	202.63	0.37
203.13	203.44	0.31
204.93	205.18	0.25
205.98	206.05	0.06
206.23	206.36	0.12
207.91	208.04	0.12
209.22	209.34	0.12
209.84	209.96	0.12
211.45	212.88	1.43
213.19	213.44	0.25
228.66	229.66	1.00
230.34	230.40	0.06
230.72	230.90	0.19
233.08	233.32	0.25
234.75	234.88	0.12
236.56	236.74	0.19
240.22	240.35	0.12
247.74	247.93	0.19
247.99	248.55	0.56
248.80	248.86	0.06

Begin Mile	End Mile	Length (mile)
249.73	250.10	0.37
250.16	250.47	0.31
254.82	255.07	0.25
255.94	256.00	0.06
257.81	258.06	0.25
259.92	260.10	0.18
262.09	262.16	0.06
263.46	263.59	0.12
263.65	264.89	1.24
265.82	266.13	0.31
266.69	266.82	0.13
267.75	267.94	0.19
269.49	269.55	0.06
271.23	271.41	0.18
275.76	275.96	0.20
276.37	276.77	0.40
324.05	324.42	0.37
334.11	334.30	0.19
341	346	5.00
356	361	5.00
410	428	18.00
492	495	3.00
525.31	525.49	0.19
526.48	526.88	0.40

Total Miles of Sensitive and Hypersensitive Areas: 130.11

Due to (a) the intermittent spacing of the sensitive and hypersensitive areas, and (b) the necessity of hydrostatically testing the pipeline in segments (from 9 to more than 20 miles in length), a significant portion of Tier I areas, for which only a proof test is required (see Longhorn Mitigation Commitment 2), will be hydrostatically tested. Test segments with a total length of 320 miles of the 457 miles of pipe between Houston and Crane (70%) will be hydrostatically tested.

ITEM 2:

WORK SCOPE
PROOF TEST

Scope:

Longhorn will proof test all portions of the pipeline between the J-1 Valve and Crane Station that have not been hydrostatically tested pursuant to Mitigation Commitment No. 1. The proof test will entail pressuring segments of the pipe with water to 1.10 times the MOP (Proof Test Pressure) for at least one hour after the pressure has stabilized.

ITEM 3:

WORK SCOPE
REPLACE PIPE OVER RECHARGE AND CONTRIBUTING ZONES

Scope:

Longhorn will replace three miles of the existing pipeline over the recharge zone of the Edwards Aquifer (approximately milepost 170.42 - 173.6) with new pipe having a minimum design factor of 0.5, which will be coated with FBE. The new pipe will be buried to a depth of cover of at least 5 feet from the top of the pipe. A red, reinforced concrete barrier will be installed below grade and above the pipe, with separation sufficient to ensure appropriate cathodic protection is maintained, to further protect against outside force damage.

Longhorn also shall replace the pipeline (a) east of the Edwards Aquifer Recharge Zone from approximately milepost 169.88 to milepost 170.42 (the beginning of the 3-mile replacement), and (b) across the Edwards Aquifer Contributing Zone from milepost 173.6 (the ending of the 3-mile replacement) to approximately milepost 188.8 (ending at the pipeline crossing of the western boundary of the Barton Creek watershed). The replacement pipe shall be buried to a depth providing a minimum 5 feet of cover to top of pipe and shall be protected with a concrete barrier. Pipe specifications shall be as stated above for the 3-mile replacement. Sensor-based leak detection shall extend across the 3-mile replacement across the Edwards Aquifer Recharge Zone and the Slaughter Creek watershed in the Contributing Zone (approximately milepost 170.42 to 178); see Mitigation Commitment Item 13.

The new pipe will be buried at such depth to reduce the potential for third party damage. This extra depth will place the line out of reach of most minor construction activities such as cable and fence installation and minor surface construction. As an additional safety measure, a concrete barrier will be installed above the pipe to further protect from third party damage. This action by Longhorn takes into account the protection of valuable water resources and the expectation of property development in South Austin, Southwestern Travis County and vicinity.

The design of the concrete barrier was chosen to maximize its protective potential and minimize installation and future maintenance costs. The replacement pipe will be installed such that the top of the pipe is a minimum of five feet below ground surface. The pipe will then be covered with at least twelve inches of porous fill to provide a reasonable buffer space. Red, fiberglass reinforced concrete will then be poured on top of the fill to a thickness of four inches and to a width equal to that of the ditch, typically three feet. The remainder of the ditch will then be filled with soil to re-establish the natural surface grade.

There are many benefits from this design. The buried concrete barrier will provide protection without creating a surface obstruction. Light construction activities such as post hole diggers, small augers, agricultural equipment and cable installation will be stopped by the reinforced concrete before the pipe surface can be reached. Because the width of the concrete extends beyond the sides of the pipe, protection is provided from trenching activities from rock saws, ditching machines and backhoes. The red color of the concrete provides a visual warning indication of an underground hazard so that it is not mistaken as natural rock or debris. Any activity that exposes the concrete will reveal this red color, including dust and cuttings from drilling operations.

During construction of the trench for the pipe replacement, any voids or fractures identified within limestone in the trench will be sealed with concrete, grout, shotcrete, or similar materials. The pipeline trench will be backfilled with sized material to create retention capacity in the event of a release. Contoured and/or bermed areas will be created to protect down gradient sensitive areas and features should released product reach the surface. See Mitigation Commitment Item 33 (b) for a description of protective measures that shall be implemented during construction.

ITEM 4:

WORK SCOPE
LONGHORN CORROSION
MANAGEMENT PLAN

This Longhorn Mitigation Commitment 4 identifies locations where Longhorn commits to complete cathodic protection system enhancements. The complete Longhorn Corrosion Management Plan is set forth within the Longhorn Pipeline System Integrity Plan, at Section 3.5.1.

Segments of concern have been divided into sixteen areas. Listed below are the location, distance, current requirement(s), additional tests and specifics for each area. Current requirement calculations are based on the present system average of 0.12mA per square foot. Impressed current cathodic protection (CP) systems and stray current interference bonds are weighed against coating reconditioning costs, through these areas. Time frames for the work to be completed will be dependent on right-of-way concerns and contractor scheduling; however, the work will be completed before startup.

A number of the stationing locations shown below differ slightly from the stationing presented in the October 1, 1999 Longhorn Mitigation Plan. The following two factors have contributed to those differences: (1) the stationing given in the October 1 Longhorn Mitigation Plan was based upon stationing recorded during the conduct of the 1998 close interval survey; and (2) testing conducted in the period between October 1 and the present has refined the stationing locations. The net result is that the stationing changes do not result in changes to the targeted conditions; rather, the changes adjust for verified stationing. Pipeline locations are identified by engineering station number and milepost (MP).

Area 1:

21836+23 – 22474+48, MP-413.56 - 425.65: The total area spans 63,825 feet with 1,765 feet of combined segments failing to meet the –0.85V criteria. 1000mA are required to bring this area to protective levels. Stray current interference testing at 22157+71, MP-419.65, 22219+89, MP-420.83, 22465+54, MP-425.48, will result in foreign bonds supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

A bond has been made at 22157+71, MP-419.65, bringing pipe to soil potentials (P/S) to protective levels (-0.90V). Additional testing will be conducted adjacent to this point to insure adequate CP levels.

Area 2:

20967+96 - 21311+21, MP-397.12 - 403.62: The total area spans 34,325 feet with 4,773 feet of combined segments failing to meet the –0.85V criteria. 2700mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 21166+01, MP-400.87 will supply the area with sufficient current to achieve adequate CP levels. Stray current interference testing at 21060+62, MP-398+88, will result in a foreign bond supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Area 3:

20863+46 - 20963+46 – MP-395.14 – 397.04: The total area spans 10,000 feet with 1,035 feet of combined segments failing to meet the –0.85V criteria. 590mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 20972+21, MP-397.20 will supply the area with sufficient current to achieve adequate CP levels. Stray current interference testing at 20869+65, MP-195.26 and 20956+67, MP-196.91 will result in foreign bonds supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Area 4:

19928+12 - 20661+96, MP-377.43 – 391.33: The total area spans 73,375 feet with 1,990 feet of combined segments failing to meet the –0.85V criteria. 1125mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 20008+64, MP-378.95 will increase current density levels between existing rectifiers to achieve adequate CP levels.

Area 5:

19162+92 - 19653+71, MP-362.93 – 372.23: The total area spans 49,052 feet with 1,020 feet of combined segments failing to meet the –0.85V criteria. 580mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 19497+01, MP-369.26 will increase current density levels between existing rectifiers to achieve adequate CP levels. Stray current interference testing at 19168+30, MP-163.40 and 19262+02, MP-164.81 will result in foreign bonds supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Area 6:

18799+01 - 19134+21, MP-356.04 – 362.39: The total area spans 33,520 feet with 3,370 feet of combined segments failing to meet the –0.85V criteria. 1910mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 18981+71, MP-359.50 will increase current density levels between existing rectifiers to achieve adequate CP levels. Stray current interference testing at 18997+82, MP-359.81 will result in a foreign bond supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Area 7:

18409+71 - 18622+21, MP-348.67 – 352.69: The total area spans 18,375 feet with 10,685 feet of combined segments failing to meet the –0.85V criteria. 6050mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 18434+21, MP-349.13 will increase current density levels between existing rectifiers to achieve adequate CP levels. Stray current interference testing at 18431+29, MP-349.08, 18433+09, MP-349.11, 18515+56, MP-350.67, 18669+07, MP-353.58 and 18597+27, MP-352.22 will result in a foreign bonds supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Area 8:

17651+24 - 18398+71, MP-334.30 – 348.46: The total area spans 74,750 feet with 6,505 feet of combined segments failing to meet the –0.85V criteria. 3680mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 18359+24, MP-347.71 will increase current density levels between existing rectifiers to achieve adequate CP levels. Stray current interference testing at 18114+07, MP-343.07, 18171+03, MP-344.15, 18182+84, MP-344.37, 18191+35, MP-344.53, and 18199+78, MP-344.69 will result in a foreign bond supplying additional current to the Longhorn line or magnesium anode magnesium anode installations, bringing it to adequate CP levels.

Area 9:

15750+74 - 16620+74, MP-298.31 – 314.79: The total area spans 87,000 feet with 6,470 feet of combined segments failing to meet the –0.85V criteria. 3660mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 15622+04, MP-295.87 and 16402+24, MP-310.65 will increase current density levels between the existing rectifiers to achieve adequate CP levels.

Area 10:

14207+24 - 14969+74, MP-269.08 – 283.52: The total area spans 76,250 feet with 3,685 feet of combined segments failing to meet the –0.85V criteria. 2090mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 14346+24, MP-271.71 will increase current density levels between the existing rectifiers to achieve adequate CP levels.

Area 11:

11837+99 – 13920+43, MP-224.20 – 263.81: The total area spans 209,125 feet with 2,080 feet of combined segments failing to meet the –0.85V criteria. 1180mA are required to bring this area to protective levels. A rectifier/groundbed system at approximate 8554+00, MP-162.00 will increase current density levels between the existing rectifiers at MP-148.96 and 174.92 to achieve adequate CP levels. Stray current interference testing at 11999+46, MP-227.26 will result in a foreign bond supplying additional current to the Longhorn line or magnesium anode installations, bringing it to adequate CP levels.

Groundbed repair was made at MP-227.90 February 24, 1999. The repaired unit provides current in this area between the existing rectifiers at MP-217.64 and 230.09. (Unit down at time of survey)

Area 12:

10484+49 - 10895+99, MP-198.57 – 206.36: The total area spans 41,150 feet with 20 feet of combined segments failing to meet the –0.85V criteria. 15mA are required to bring this area to protective levels. Magnesium anode installations and coating reconditioning at 10485+60 – 10487+10, MP-198.59 – 198.62 (150 feet) and 10892+76 – 10893+51, MP-206.30 – 206.32 (75 feet) and will bring the segment to adequate CP levels. The 1998/1999 survey crew was forced to skip 10753+40 – 10811+06, MP-203.66 – 204.75 due to landowner refusal to allow access.

Area 13:

8550+99 - 8943+96, MP-161.95 – 169.39: The total area spans 39,297 feet with 4302 feet of combined segments failing to meet the –0.85V criteria. 2440mA are required to bring this area to protective levels. The 1998/1999 survey crew was forced to skip 8897+68 – 8945+40, MP-168.52 – 169.42 (4772) feet of this section due to "bad dogs," though P/S potentials remain well above – 1.00V for over five miles either side of this segment. A rectifier/groundbed system at approximate 8591+24, MP-162.71 will insure adequate CP levels.

Area 14:

6582+17 – 7084+49, MP-124.66 – 134.18: The total area spans 50,232 feet with 285 feet of combined segments failing to meet the –0.85V criteria. 165mA are required to bring this area to protective levels. Magnesium anode installations and coating reconditioning at 7066+29 – 7066+79, MP-133.83 – 133.84 (50 feet) and 6582+17 – 6585+67, MP-124.66 – 124.73 (350 feet) will bring the segment to adequate CP levels.

Area 15:

6170+84 - 6181+49, MP-116.87 – 117.07: The total area spans 1065 feet with 135 feet of combined segments failing to meet the –0.85V criteria. 76mA are required to bring this area to protective levels. However, adjacent potentials are reaching borderline. A rectifier/groundbed system at approximate 6170+84, MP-116.87 will increase current density levels between the existing rectifiers to maintain adequate CP levels.

Area 16:

1729+24 – 3243+90, MP-32.75 – 61.44: The total area spans 151,466 feet with 90 feet of combined segments failing to meet the –0.85V criteria. 55mA are required to bring this area to protective levels. Magnesium anode installations and coating reconditioning at 2054+04 – 2055+04, MP-38.90 – 38.92 (100 feet), 2800+51 – 2801+01, MP-53.04 – 53.05 (50 feet) and 3243+40 – 3243+90, MP-61.43 – 61.44 (50 feet) will bring the segment to adequate CP levels. The 1998/1999 survey crew was forced to skip 1729+24 – 1734+81, MP-32.75 – 32.86 (557 feet) of this section due to "attack dogs," however, P/S potentials remain above the -0.850V on either side of this segment.

Casings:

Casing tests and necessary remedial action at 691+36, MP-13.09, 807+75, MP-15.30, 822+20, MP-15.57, 846+10, MP-16.02, 931+27, MP-17.64, 1202+68, MP-22.78, 1251+54, MP-23.70, 1283+26, MP-24.30, 1467+80, MP-27.80, 1805+42, MP-34.19, 3328+56, MP-63.04 and 9357+25, MP-177.22 will mitigate high casing to soil potentials and detrimental effects.

ITEM 5:

WORK SCOPE
SHALLOW/EXPOSED PIPE
DESIGNATED SENSITIVE AND HYPERSENSITIVE AREAS

Scope:

Information gained from the designation of Sensitive and Hypersensitive Areas on the Longhorn Pipeline System identified shallow or exposed locations within such areas which will be addressed to ensure safe and reliable operation of the system.

With the exception of the Marble Creek crossing (discussed below), when pipe is lowered or replaced pursuant to this Longhorn Mitigation Commitment 5, the pipe will be buried to a minimum depth of cover equal to or greater than 5 feet from top of pipe, or measures will be employed to achieve an equivalent 5 feet of cover, such as a concrete cap. If, after excavation, it is determined that any pipe needs to be replaced, new pipe will be installed as described in Section 1.2 of this Mitigation Plan.

If after excavation it is determined to lower the existing pipe, the coating will be inspected and repaired if necessary.

In addition, the Longhorn Pipeline crossing of Marble Creek will be replaced with new pipe meeting the minimum pipe grade specifications described in Section 1.2, and Longhorn shall refurbish the pipe supports to provide additional lateral support. Safety gates will be installed on either side of the crossing to deter access onto the pipe.

The sites targeted as a part of this mitigation measure are stated in the table below. Variances between stationing shown below and that shown in the October 1, 1999 Longhorn Mitigation Plan result from field investigation to more precisely identify and mitigate the risk factors that work in favor of lowering the pipeline. Furthermore, certain sites listed below will be incorporated into the pipe replacement project across the Edwards Aquifer Recharge and

Contributing Zones (see Mitigation Commitment Item 3); those sites are LPP-2467, LPP-2471, LPP-2546, and LPP-2627.

Site	Begin Station	End Station
LPP-2287	8767+24, MP166.05	8768+24, MP166.07
LPP-2358	8895+16, MP168.47	8896+74, MP168.50
LPP-2362	8899+49, MP168.55	8917+39, MP168.89
LPP-2467	9195+80, MP174.16	9197+24, MP174.19
LPP-2471	9220+80, MP174.64	9222+24, MP174.66
LPP-2546	9483+31, MP179.61	9488+24, MP179.70
LPP-2627	9807+10, MP185.74	9807+42, MP185.75
LPP-2713	10200+44, MP193.19	10200+71, MP193.20
LPP-2751	10369+55, MP196.39	10373+24, MP196.46
LPP-2753	10380+60, MP196.60	10381+24, MP196.61
LPP-3386	12498+16, MP236.71	12498+40, MP236.71
4006	7608+56, MP144.1	7609+43, MP144.1
6001	5996+88, MP113.6	5997+50, MP113.6

ITEM 6:

WORK SCOPE
STOPPLE REMOVAL

Scope:

Three potential stopple fittings have been identified in internal pipeline inspection data. These fittings will be removed due to the potential for leaks. A plan has been initiated to remove these fittings by exposing the locations, cutting out the section containing the fitting, and replacing it with new pipe.

The stopples are identified at the following locations:

- STOP-1 at Station Number 9071+36, MP171.81
- STOP-2 at Station Number 8936+35, MP169.25
- STOP-3 at Station Number 8796+99, MP166.61

All cutout sections will be replaced with new pipe as described in Section 1.2 of this Mitigation Plan. Site STOP-1 will be incorporated into the pipe replacement project across the Edwards Aquifer Recharge and Contributing Zones (see Mitigation Commitment Item 3).

ITEM 7:

WORK SCOPE
POSSIBLE CORROSION ANOMALIES

<u>Scope</u>:

Internal pipeline inspection tools have indicated the possible presence of corrosion at two locations on the Longhorn Pipeline System, at Stations 1821+62, MP34.50 and 2737+37, MP51.84, near Satsuma Station in Harris County and in Waller County, respectively. Longhorn has initiated a plan to investigate the presence of these two corrosion indications by exposing these locations and comparing actual conditions to those indicated by the inspection tool. If corrosion is present where indicated, Longhorn will remove and replace the corroded pipe as a cylinder with new pre-tested line pipe in lengths of 2 pipe diameters (3 feet) or greater.

If inspection of either segment reveals corrosion, the segment will be replaced with new pipe as described in Section 1.2 of this Mitigation Plan.

ITEM 8-1:

WORK SCOPE
RABBS CREEK LOWERING

<u>Scope</u>:

The scope of work at Rabbs Creek consists of removal of the existing exposed pipeline crossing (approximately 2,600') and the related pipe supports. Subsequent to removal of the old pipeline, a new replacement will be performed. The new pipe will be installed with a minimum 5 foot depth of cover under the creek. The crossing will be replaced with new pipe as described in Section 1.2 of this Mitigation Plan. Concrete coating will be utilized for buoyancy control.

ITEM 8-2:

WORK SCOPE
POSSIBLE PIPE DENTS

<u>Scope</u>:

Internal inspection tools run in the Longhorn Pipeline System have identified twenty-three possible dent locations in the pipe. To ensure these locations pose no threat to the pipeline, Longhorn will excavate and inspect the five dent locations with the most severe indications as indicated in the survey. If dents are confirmed at any of these locations, the remaining eighteen locations will be excavated and inspected. During the Environmental Assessment, Longhorn re-evaluated the inspection data and refined the locations of the suspected dents. The listing below sets out the five revised investigation locations

In the event any dent meets the following criteria, the dented pipeline section will be replaced as a cylinder with new pre-tested pipe:

- The dent is of sufficient severity to pose an impediment to pig passage.
- The dent is in excess of the deformation limits defined in ANSI/ASME B31.4 (6% of the nominal pipe diameter).
- The dent contains stress concentrators (such as a scratch, gouge, groove, or arc burn)
- The dent affects the curvature of the pipe at the longitudinal seam or any girth weld.

The following five sites will be investigated (revised locations are shown):

- Dt-9 at 14012+73 (MP265.39)
- Dt-12 at 12659+39 (MP239.76)
- Dt-17 at 3142+26 (MP59.51)
- Dt-19 at 2350+02 (MP44.51)
- Dt-20 at 2073+52 (MP39.27)

If, after excavation, it is determined that any pipe needs to be replaced, new pipe will be installed as described in Section 1.2 of this Mitigation Plan.

ITEM 9:

WORK SCOPE
MAXIMUM ALLOWABLE SURGE PRESSURE ANALYSIS

Scope:

Longhorn pipeline commissioned, via a qualified third party engineering contractor, a surge analysis study of the Longhorn system. The analysis assumed a line fill of 100% diesel fuel, which is an extremely conservative assumption. Surge exceedencies were identified in the analysis which resulted from inadvertent valve closures or pump station shut downs. In order to ensure the safety and integrity of the system, Longhorn will hydrostatic test the areas in the following table where exceedencies were identified to requalify the pipeline, so that the resulting maximum surge pressure will be less than 110% of the MOP that results from the hydrostatic test.

Surge Analysis Areas Identified to be Hydrostatically Tested

Milepost	Total Miles	Re-Qualification MOP
34.1 – 63.8	29.7	1012
113.0 – 133.9	20.9	1012
181.7 – 198.9	17.2	1123
441.9 – 455.7	13.8	1040
	81.6	

As an additional safety measure, Longhorn is addressing all Tier II and III areas of the pipeline to eliminate the possibility of conditions causing a surge pressure which would exceed MOP. As a result of these measures, there will be no Tier II or III area which will exceed MOP under surge conditions resulting from the inadvertent valve closures or pump station shut downs discussed above.

All sections to be hydrostatically tested during this safety and integrity verification will be tested to a minimum of 90% of SMYS in order to ensure acceptable operating pressure ranges. The period of testing will be no less than eight hours in duration.

If segments fail during the test, they will be repaired, and after any such repairs the segment will be tested to achieve a complete 8 hour test. Either during repairs or after completion of the test, failed segments will be replaced with new pipe as described in Section 1.2 of this Mitigation Plan. In the event of a failure, the test will be restarted until the test is successful.

ITEM 10:

WORK SCOPE
TRANSVERSE FIELD MAGNETIC FLUX INSPECTION

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 to examine longitudinal weld seams for flaws and to examine the pipe body for cracks. Pipe flaws identified by the inspection tool will be addressed in accordance with the procedures described in the Longhorn Pipeline System Integrity Plan, In-Line Inspection and Rehabilitation Program process element, at Section 3.5.2 of this Mitigation Plan. Such testing shall be conducted at intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 3 years after system startup in Tier II and III areas. See the Longhorn Pipeline System Integrity Plan at Section 3.5.2 and the associated Operational Reliability Assessment at Section 4.0.

ITEM 11:

WORK SCOPE
HIGH RESOLUTION MAGNETIC FLUX INSPECTION

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 to evaluate the pipeline for the presence of corrosion and other flaws. Pipe flaws identified by the inspection tool will be addressed in accordance with the procedures described in the Longhorn Pipeline System Integrity Plan, In-Line Inspection and Rehabilitation Program process element, at Section 3.5.2 of this Mitigation Plan. An inspection shall be conducted within three months of system startup and thereafter at such intervals as are established by the Operational Reliability Assessment. Until Mitigation Item 11 has been completed, an interim MOP (MOPi) shall be established for the existing pipeline at a pressure equal to 0.88 times the MOP. (NOTE: 1.25 times the MOPi is equal to the Proof Test Pressure discussed in Mitigation Item 2 above). See the Longhorn Pipeline System Integrity Plan at Section 3.5.2 and the associated Operational Reliability Assessment at Section 4.0.

ITEM 12:

WORK SCOPE
ULTRASONIC WALL MEASUREMENT INSPECTION

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 to verify wall thickness and locate laminations and other mill related anomalies. Pipe flaws identified by the inspection tool will be addressed in accordance with the procedures described in the Longhorn Pipeline System Integrity Plan, In-Line Inspection and Rehabilitation Program process element, at Section 3.5.2 of this Mitigation Plan. Such testing shall be conducted at intervals as are established by the Operational Reliability Assessment, provided that an inspection shall be performed no more than 5 years after system startup. See the Longhorn Pipeline System Integrity Plan at Section 3.5.2 and the associated Operational Reliability Assessment at Section 4.0.

ITEM 12A:

WORK SCOPE
"SMART" GEOMETRY INSPECTION

Longhorn shall perform an in-line inspection of the existing pipeline (Valve J-1 to Crane) with a "smart" geometry inspection tool to identify dents and other flaws affecting pipe geometry. Pipe flaws identified by the inspection tool will be addressed in accordance with the procedures described in the Longhorn Pipeline System Integrity Plan, In-Line Inspection and Rehabilitation Program process element, at Section 3.5.2 of this Mitigation Plan. Such testing shall occur at such intervals as are established by the Operational Reliability Assessment, provided that no more than 3 years shall pass without an in-line inspection being performed using an inspection tool capable of detecting third party damage, such as TFI, HRMFL, or geometry tools. See the Longhorn Pipeline System Integrity Plan at Section 3.5.2 and the associated Operational Reliability Plan at Section 4.0.

ITEM 13:

WORK SCOPE
ENHANCED LEAK DETECTION

<u>Objective:</u>

The objective of this program is to identify the Longhorn Release Detection Systems that will be employed to minimize both the leak identification time and the shutdown time required to minimize the size and impact of a potential leak on the Longhorn Pipeline System.

<u>Leak Detection Systems:</u>

Leak detection for the unintended escape or potential loss of product from Longhorn Pipeline incorporates the use of a combination of visual, mechanical, and analytical processes, equipment, and models. Collectively, Longhorn's Leak Detection System capabilities, which provide for several areas of overlap, are designed to significantly reduce the likelihood of a protracted period of undetected pipeline system breaches and continued pipeline operations that would adversely contribute to human or environmental exposure to hydrocarbon products. Heightened awareness of the designated sensitive and hypersensitive areas along the Longhorn pipeline has resulted in the employment of enhanced leak detection technology and processes.

Longhorn's Leak Detection System is comprised of two primary components: External Patrols; and Technology Based systems. By design, these two areas of leak detection provide redundancy and assurance that a release will be detected within the shortest time possible using current best available technology.

External Patrols:

External Patrol of the Longhorn Pipeline System is primarily accomplished through the targeted activities of Longhorn Operations and directed third party surveillance contract personnel. Some of these activities include aerial patrol, inspection of water crossings, ground based right-of-way patrol, tank dike inspection, scheduled inspections of valve locations, surface facilities, buried road crossings, and DOT regulatory based activities.

External Patrol is also enhanced through the incorporation of data obtained through normal pipeline maintenance activities, such as those accomplished via cathodic protection inspections, One-Call line spotting, and physical pipeline examination during pipeline exposures.

Another important source of input under the category of External Patrol results from the involvement of the general public, emergency response organizations, contractors, and other third party sources. These groups are specifically targeted via Longhorn's Damage Prevention Program (see Longhorn Pipeline System Integrity Plan) and other activities which are designed to instill awareness of the location of the pipeline corridor. Further, active public education programs are designed to result in an increase in public knowledge by which to primarily avoid, but to secondarily recognize, any activities that could reasonably lead to adverse effects to the pipeline system. With pipeline location awareness, product characteristic information, and emergency response phone numbers and points of contact, the general public, emergency responders, contractors, and other third party groups serve as further insurance that system leaks can be minimized from third party damage, may be recognized if one occurs, and in that case be communicated to Longhorn Operations personnel.

External Patrol leak detection is dependent upon the physical identification of some abnormality or change from the characteristics of the surrounding area of the pipeline corridor. Physical evidence can include a hydrocarbon odor, a sheen on a water surface, spraying product, bubbles along the ground, discoloration of soil, areas of vegetation "browning," and fires in near proximity to the pipeline assets. Similar to many other methods of leak detection, External Patrol leak detection can readily identify a moderate to major product release. Smaller leaks, be they from pinhole leaks or leaking pipeline components, often require more time to trigger the physical indicators such as defoliation or odor which indicate a potential product leak.

Technology Based:

Longhorn will employ a leak detection software system to monitor the operation of its pipeline system. This system represents the current best available, proven technology in the industry. The leak detection software is a transient model that is designed to analyze and compare the actual pipeline operations of pressures and flow rates against theoretical values during both steady state and changing conditions. Deviations between actual and theoretical values result in alarm indications and notification to the Operations Control Center for subsequent review, analysis, investigation, and if appropriate shutdown of the pipeline system.

Longhorn approached the selection of a computational based leak detection software system through the employment of a highly respected third party consultant who has demonstrated experience in the field of pipeline SCADA systems and leak detection, along with a current understanding of leak detection technologies and performance capabilities. Leak detection performance requirements, based upon demonstrated industry achievable levels and best available transient model technology, were developed by Longhorn's consultant and approved by Longhorn's management. Computational based Leak Detection "Requests For Proposals" were sent to several prospective vendors, and responses were returned to Longhorn's consultant for detailed review and evaluation. The review/analysis process included clarifying discussions with the vendors, technical presentations, and detailed reference checks with provided customer lists. This process yielded two vendors who were judged to be capable of meeting the leak detection performance requirements established by Longhorn. Further discussions with the two "finalists" resulted in the selection of the computational based leak detection software system that was determined to have the higher degree of leak detection performance.

The software based leak detection system is fundamentally a volume (mass) balance system that employs a fully transient model. The flow balance calculated from flow measurements is corrected by the packing rate, which is calculated by the "real-time" model. The resulting volume balance allows calculation of potential leak indicators. A leak would be identified by comparing the node flow balances at measurement points. The model dynamically tracks changes in the pipeline's flow rate. Variation between modeled and measured flow shows up in the volume balance calculation. The rate of change of all boundary measurements affects the leak detection by affecting the model directly, as well as the dynamic thresholds. Leak alarm thresholds are provided for each volume balance section and averaging interval.

The SCADA system used for the Longhorn pipeline system operates on Neles (formerly Valmet Automation) Oasys software version 5.2. Longhorn operator Williams subscribes to the Neles maintenance program which provides software program updates. Williams maintains the most current revision of version 5.2. The Neles Oasys system provides an extremely reliable communication and control link with the pipeline system components. For example, in 1999 the SCADA system experienced 99.954% reliability (after deduction for Y2K testing). The 0.046% down time for that year is attributable to a single four-hour service outage. Thus, it is very unlikely that the SCADA system would be out of service for any appreciable amount of time.

A SCADA system outage could result in a loss of leak detection system sensitivity. An outage which does not affect the entire SCADA system can occur, for example, with the loss of data from a remote terminal unit (RTU) at a pump station for more than three minutes, in which case an alarm sounds in the Control Center to alert the controller. Under such circumstances, the system uses backup land line communications links to reestablish communications. However, the leak detection system is able to maintain its detection capability by modeling across the point of data loss. A loss of SCADA communications that affected the entire system, for example because of a computer malfunction, would immediately be known to the controller. If the SCADA system experiences any outage that results in a total loss of leak detection capability for all or any portion of the pipeline for a period in excess of 5 minutes, then the controller will take action to achieve system shutdown within 30 minutes. In the event that the SCADA system experiences an outage that does not result in a loss of leak detection capability, but instead results in a diminished capability of the system to detect a leak, then the controller will take action to achieve system shutdown within 30 minutes if the capability of the system to detect leaks is diminished to a level that would prevent Longhorn from meeting its "Leak Detection Performance Commitment" set out below.

Further Enhancement:

In addition to the computational based leak detection system, Longhorn has committed to employ additional technology to provide for more stringent leak detection across the environmentally sensitive Edwards Aquifer Recharge Zone and the Slaughter Creek watershed in the Edwards Aquifer Contributing Zone (the "Enhanced Leak Detection System"). In order to achieve this capability, Longhorn plans to employ a hydrocarbon sensing leak detection cable system that has clearly demonstrated the leak detection capability to satisfy Longhorn's commitment contained within Mitigation Commitment 13.

This system is designed to detect a leak as small as 0.0030467 barrel per hour in twelve (12) to one hundred twenty (120) minutes from contact with the leak detection cable, depending upon the product sensed by the system. Several factors will make it probable that any released product will come into contact with the leak detection cable within a minimum amount of time, including the following: (a) the construction methods that Longhorn will employ over the recharge and contributing zones during replacement of this segment of pipe, including protection of all identified subsurface voids; and (b) backfill materials used within the trench (primarily fine materials to provide padding to the pipe and otherwise relatively porous media), coupled with the primarily limestone geology of the Edwards outcrop and the fact of the in-trench materials having been disturbed will cause any released product to accumulate within the trench where the leak detection cable will be located. Longhorn has committed to having this system in place prior to start-up of the pipeline.

The hydrocarbon sensing leak detection system is based upon the TraceTek hydrocarbon sensing cable manufactured by Raychem HTS. Longhorn's ultimate choice of the TraceTek cable was made after Longhorn, Williams and UTSI International Corporation performed exhaustive research of leak detection technology potentially feasible for this particular application. After detailed analysis of potentially feasible leak detection technologies, and consultation with the Office of Pipeline Safety, the TraceTek cable was identified as the current best available, proven technology in the industry. The table below identifies the sensing capabilities of the TraceTek system.

<u>Leak Detection Response</u>:

With notification typically originating through the utilization of its External Patrol and Technology Based components of its Leak Detection System Capabilities, Longhorn Pipeline will facilitate the orderly and controlled shutdown of its system within five (5) minutes of a probable leak indication.

Longhorn maintains 24-hour surveillance of its pump stations, motorized valve locations (MOV), terminals (pipe, pumps, valves, meters, and tanks), and meter stations through its SCADA system. (Truck loading operations at the El Paso Terminal are monitored locally.) Twenty-four-hour surveillance will also be maintained with respect to Longhorn's Enhanced Leak Detection System. Pipeline operational data from these locations is transmitted directly to the Tulsa Operations Control Center, where trained and qualified Operations Control personnel monitor and provide equipment control commands to the Longhorn system.

Operations Control personnel utilize the following methods for the determination or suspicion of a probable leak indication:

- Deviation outside normal operational thresholds from the computational based transient leak detection software system in a direction that is indicative of a leak;
- Receipt of an alarm by the sensor cable system over the Edwards Aquifer Recharge Zone;
- Unexpected deviation outside minimum or maximum alarm thresholds for system pressures and flow rates;
- Rate of Change alarms that compare pressure or flow value change versus time;
- Operations Control personnel independent analysis of flowing conditions;
- Third party call of suspected or confirmed product leak;
- Input from Field Operations Personnel;
- Automatic closure of MOV's or stoppage of pipeline pumps;
- Terminal high level alarms.

Analysis of a suspected pipeline leak is accompanied by an identification of the location of the suspected leak.

Upon the detection, notification, and determination of a probable leak indication, Operations Control personnel are trained to immediately shut down the pump station(s) upstream to the leak location. The pump station downstream to the leak location is either kept running or is started to assist with the orderly movement of product away from the leak location. Following the shut down of the upstream pump(s), the Operations Control personnel will close the upstream MOV's from the leak location to prevent the introduction of new product to the segment. Through the use of the SCADA system, upstream pump stoppage and MOV closure are accomplished within five (5) minutes from the identification of a probable leak indication.

The Longhorn Pipeline was designed to be shut down immediately following a probable leak indication. Communication with field operations, product origination or destination points and terminals are not required to shut down the pipeline in an orderly or safe fashion. Operations Control personnel are trained to notify the appropriate supply, destination, field operations, and emergency responder personnel as soon as practical following the shut down and isolation of the pipeline.

The above emergency shut down procedures will be documented and tested for Operations Control personnel training certification prior to start-up of the Longhorn Pipeline system.

The Longhorn pump stations utilize a Programmable Logic Controller (PLC) to handle the start-up, sequencing, data transmittal, and shut down of the equipment within the station. The Tulsa Operations Control Center sends command signals to and receives operational data from the PLC's at each pump station. The PLC's, coupled with the instrumentation contained at each pump station, serve to protect the pump equipment from mechanical disturbances such as vibration, abnormal motor winding or pump bearing temperatures, loss of product through seal leaks, and fire sources. Internally, the pump equipment is protected from conditions of high product flow, low product flow, low system pressure, high system pressure, and excessive or low motor amperage. The PLC is programmed to provide both early indication alarm and automatic pump shutdown in the event that designated parameters are operated outside their intended range.

Pressure, flow, and tank level readings from across the pipeline system are transmitted to the Tulsa Control Center via the SCADA system for computational transient modeling analysis and Operations Controller interpretation of the physical data, as is the data generated by the Enhanced Leak Detection System. The status of the sensor cable system over the Edwards Aquifer Recharge Zone also is transmitted to the Tulsa Control Center. Outside of the automatic shut down of pump units that are controlled by the local pump station PLC's, shut down of equipment and isolation of MOV's are originated by the Operations Controller.

Leak Detection Performance Commitment:

Longhorn is committed to implementing the best available leak detection systems with the following design specifications:

LOCATION	SYSTEM DESIGN SPECIFICATIONS
Tier I	• 1% of flow detected within one-half hour.
Tier II	• 1% or more of flow detected within one-half hour. • 0.5% - 1% of flow detected within one hour.
Tier III	• Same as Tier II, except Edwards Aquifer Recharge Zone.

Edwards Aquifer Recharge Zone and Contributing Zone (Slaughter Creek watershed)	Same as Tier II, and sensor-based detection of 0.0030467 barrel/hour from contact for the following products: • Gasoline – 12 minutes • Diesel Fuel – 60 to 120 minutes • Jet Fuel – 50 to 70 minutes • Crude Oil - 100 to 200 minutes

The leak detection equipment will be installed prior to startup. The computational based system will be adjusted to become operational over approximately the first two weeks of pipeline operation and be further optimized within 6 months of startup. The sensor-based system will be fully operational, at full sensitivity, immediately upon startup. Leak detection capabilities will be demonstrated and periodically tested.

ITEM 14:

WORK SCOPE
CLOSE INTERVAL SURVEYS

Longhorn shall perform close interval 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 [MP203.66 – 204.75], 8897+60 – 8945+40 [MP168.52 – 169.42], and 1729+24 - 1734+81 [MP32.75 – 32.86]), and will remediate any corrosion related conditions identified by the surveys as necessary. These surveys, to be completed before project startup, will ensure adequate cathodic protection in hypersensitive areas and in areas not covered by the 1998 close interval survey.

ITEM 15:

WORK SCOPE
PIPELINE SPAN SUPPORT

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 of the pipeline across the Colorado River.

ITEM 16:

WORK SCOPE
ENCROACHMENTS

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 have been identified in Travis County between

Milepost 164 and 168. These and other potential encroachments will be evaluated using the guidelines found in Section 3.5.5, Encroachment Procedures, of the Longhorn Pipeline System Integrity Plan. Longhorn shall implement this commitment within one year of project startup.

ITEM 17:

WORK SCOPE
RIGHT-OF-WAY CLEARING

Longhorn Pipeline shall clear all right-of-way to excellent condition before start up. Further, Longhorn shall maintain all right-of-way in excellent condition after startup. Excellent condition will be considered that condition which will provide a clear line of sight for aerial and/or ground surveillance patrols in order to effectively monitor and inspect the right-of-way. As well, where the surrounding terrain is natural or heavily developed, a clean and clearly marked right-of-way will provide a distinctive line of demarcation indicating a change in land use.

Ground cover will be mowed to a level so that all pipeline markers, including painted fence posts, will be visible from the air and while standing on the ground. The Longhorn "Damage Prevention Program," Section 3.5.4 of The Longhorn Pipeline System Integrity Plan, provides specific information regarding the number, location, and maintenance of pipeline markers for the Tier I, Tier II (sensitive), and Tier III (hypersensitive) areas along the pipeline route. High canopy vegetation will be cleared or trimmed to the extent necessary to allow clear visibility. All debris will be cleared from the right-of-way.

Every consideration will be given to endangered species while conducting clearing activities in and around the pipeline right-of-way. Maps depicting the location and habitats of endangered species, developed by qualified biologists, will be utilized for this purpose. Timing of all clearing activities will be coordinated to avoid, or minimize, potential adverse effects to threatened and endangered species in accordance with Longhorn's consultation with the U.S. Fish and Wildlife Service.

Right-of-way encroachments shall be resolved pursuant to Longhorn Mitigation Commitment 16. See Longhorn Mitigation Commitment 16 in Section 1.2 and Encroachment Procedures, Section 3.5.5 of the Longhorn Pipeline System Integrity Plan.

ITEM 18:

WORK SCOPE
SHALLOW/EXPOSED PIPE
RESULTING FROM DEPTH OF COVER SURVEY

Scope:

Information provided from a Depth of Cover Survey performed on the Longhorn Pipeline System identified shallow or exposed locations which will be addressed to ensure safe and reliable operation of the Longhorn Pipeline System. These locations are in addition to those identified within sensitive and hypersensitive areas which are addressed in Longhorn Mitigation Commitment 5.

In all cases when pipe is lowered or replaced pursuant to this Longhorn Mitigation Commitment 18, the pipe will be buried to a minimum depth of cover equal to or greater than 5 feet from top of pipe, or measures will be employed to achieve an equivalent of 5 feet of cover, such as a concrete cap. If, after excavation, it is determined that any pipe needs to be replaced, new pipe will be installed as described in Section 1.2 of this Mitigation Plan. Variances between stationing shown below and that shown in the October 1, 1999 Longhorn Mitigation Plan result from field investigation to more precisely identify and mitigate the risk factors that work in favor of lowering the pipeline.

The sites targeted as a part of this mitigation measure are:

Site	Begin Station	End Station
S-01	21350+65, MP404.37	21354+65, MP404.44
S-10	18857+96, MP357.16	18862+01, MP357.24
S-11	18853+55, MP357.07	18857+96, MP357.16
S-12	18429+02, MP349.03	18435+02, MP368.09
S-13	18389+76, MP348.29	18396+83, MP348.42
S-14	18384+33, MP348.19	18387+59, MP348.25
S-15	18372+95, MP347.97	18376+21, MP348.03
S-16	18329+74, MP347.15	18334+74, MP347.25
S-17	18319+74, MP346.96	18326+99, MP347.10
S-18	18259+74, MP345.83	18264+84, MP345.93
S-19	18214+74, MP344.98	18218+24, MP345.04
7006, 7007	13586+41, MP257.32	13586+83, MP257.33
S-30	12331+00, MP233.54	12336+50, MP233.65
2016	11725+22, MP222.07	11725+71, MP222.08
S-31	8869+24, MP167.98	8873+24, MP168.05
S-32	8365+89, MP158.44	8368+89, MP158.50
2013	5577+82, MP105.64	5577+85, MP105.64
4015	4078+64, MP77.25	4079+10, MP77.26
S-35	1875+17, MP35.51	1879+17, MP35.59
HS-01	893+22, MP16.92	895+22, MP16.95
HS-02	890+07, MP16.86	892+72, MP16.91
HS-03	858+38, MP16.26	861+88, MP16.32
HS-04	824+22, MP15.61	827+22, MP15.67
HS-05	798+07, MP15.11	800+87, MP15.17
HS-06	677+87, MP12.84	680+18, MP12.88
HS-07	485+87, MP9.20	490+37, MP9.29

ITEM 19:

WORK SCOPE
ENGINEERING / TECHNICAL ANALYSES AND STUDIES

Stress Corrosion Cracking Study

A study has been performed to determine whether factors that could contribute to stress corrosion cracking (SCC) are present on the Longhorn System. This study was performed on the entire length of the pipeline from GATX to El Paso. No evidence of cracking was identified and thus none was unavailable for comparison with industry data and other published information regarding SCC.

This study was commissioned by Longhorn Pipeline and conducted by a reputable third party company with demonstrated engineering expertise and system analysis/assessment competencies.

Longhorn will nonetheless incorporate monitoring for SCC into the Operational Reliability Assessment. See Section 3.3 of the Longhorn Pipeline System Integrity Plan.

Ground and Water Force Studies

Longhorn has performed detailed studies of ground and water forces that could affect the pipeline. The following potential forces which could affect the pipeline were analyzed: (a) Scour, erosion, and flood potential, with the potential effects of overland floodwater movement on the pipeline to be addressed toward minimizing the risk of exposure as a result of severe flooding or scour conditions; (b) Seismic activity; (c) Ground movement, subsidence and aseismic faulting; (d) Landslide potential; and (e) Soil stress.

The studies include an information review of surface faulting, soil environments, and flooding along the pipeline route, including aerial photography review and/or area or site reconnaissance to identify faulting and flooding activity along the pipeline route. The studies have been presented in report format.

Longhorn shall implement the mitigation recommendations of the above studies prior to startup of the pipeline system. In addition, Longhorn shall develop and implement programs to monitor potential subsidence and aseismic faulting in the Houston area to ensure that pipeline integrity is protected from such forces. Monitoring results will be incorporated into the Longhorn Pipeline System Integrity Plan and the Operational Reliability Assessment.

Longhorn shall replace the pipeline crossing of Barton Creek (9552 + 70, MP 180.9) in Hays County to a depth sufficient to avoid potential streambed scour. Pipe specifications shall be as stated in Mitigation Commitment Item 3. The Barton Creek replacement shall be incorporated into the pipe replacement project across the Edwards Aquifer Recharge and Contributing Zones. See Mitigation Commitment Item 3.

The findings of the above studies will be incorporated into the Longhorn Pipeline System Integrity Plan (see Section 3.2.2).

Root Cause Analysis

Formal root cause analysis methodology has been used to evaluate root cause of failures and damage resulting in repairs and involved a comprehensive study of each historical incident. First, all possible causes of the damage were identified. Then, the most likely cause(s) of the damage were identified, which included a thorough review of contributing factors which led to the damage.

The root cause analysis determined whether an incident is "isolated" or whether a trend either exists or is developing with respect to any particular incident. To the extent the analysis revealed a trend, the analysis identified appropriate actions which will be taken in order to mitigate the cause and eliminate the future occurrence of similar damage. The analysis identifies both current practices and mitigation actions that are being or will be taken to counteract the cause and eliminate the future occurrence of similar damage. Mitigation of trends could include training to recognize issues, altering operational procedures, or engineering changes to the system, all of which will be designed to arrest the continuation of the identified contributing factors or trend.

Longhorn will incorporate operational improvements identified as a result of root cause analysis studies into the Longhorn Pipeline System Integrity Plan and input the results into the Operational Reliability Assessment (See Section 3.3 of the Longhorn Pipeline System Integrity Plan).

ITEM 20:

WORK SCOPE
FREQUENCY OF PATROLS

Longhorn shall increase the frequency of pipeline surveillance patrols in hypersensitive and sensitive areas to every two and one-half days (not to exceed 72 hours), daily in the Edwards Aquifer area, and weekly (not to exceed 12 days, but at least 52 times per calendar year) in all other areas. This mitigation commitment shall be implemented continuously after startup. See Longhorn Pipeline System Integrity Plan (Section 3.0), Damage Prevention Program element (Section 3.5.4).

ITEM 21:

WORK SCOPE
REMOTE MONITORING OF PUMP STATIONS USING CAMERAS

Remote video cameras will be installed at all existing pump stations within 6 months of startup. Cameras will be placed at an appropriate vantage point so that all key equipment within a pump station may be inspected to verify that a safe operating environment exists. The capability of these cameras to pan and zoom will allow Longhorn personnel to closely view all key equipment in the pump station so that site conditions may be observed and monitored and so that any malfunction can be monitored until dispatched personnel arrive. The cameras will be utilized to investigate remote alarm indications, to assist with diagnostic troubleshooting and situational analysis, and to provide additional guidance and information to on-site response coordination with operations, technical, and emergency personnel.

All remote monitoring activities will be performed from the Tulsa Control Center, 24 hours per day. Color monitors are used which allow for clear definition of pump station equipment at the component level.

Future stations will have remote cameras installed prior to station startup.

ITEM 22:

WORK SCOPE
STUDY OF VALVES AT WATER CROSSINGS

Longhorn will perform 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 the James River.

This study will be conducted by Longhorn Pipeline and will follow a methodology similar to that shown in the *California State Fire Marshal Hazardous Liquid Pipeline Risk Assessment (1993).* Once completed, Longhorn shall determine, on the basis of the study, whether additional valves will be beneficial, and Longhorn shall obtain DOT/OPS concurrence in the determination. If it is determined that additional valves will be beneficial, Longhorn will implement such changes to the system and complete the changes within six months of notice from OPS.

Longhorn will submit any system modifications into the Longhorn Pipeline System Integrity Plan and input the results into the Operational Reliability Assessment. (See Section 3.3 of the Longhorn Pipeline System Integrity Plan.)

ITEMS 23, 24 and 26:

WORK SCOPE
ENHANCED FACILITY RESPONSE PLAN

Longhorn Commitment:

Develop and implement an enhanced Facility Response Plan, which includes enhanced response planning in environmentally sensitive and populated areas to supplement the existing DOT OPA '90 Oil Spill Response Plan. This Plan will include the identification of additional fire fighting and environmental remediation capabilities outside of metropolitan areas.

Approach:

Longhorn will acquire response resources for a 2 hour full response time for sensitive (Tier II) areas along the pipeline, and acquire resources for a 1 to 2 hour response in hypersensitive (Tier III) areas. In addition, Longhorn shall expand the Facility Response Plan to have more detailed planning in areas of high populations of potentially sensitive receptors, and plan and identify resources for fire fighting outside the metropolitan areas.

Longhorn Pipeline will use the following approach to develop an Enhanced Facility Response Plan for population sensitive segments of its pipeline.

Phase I:

Evaluate the resources currently available along the pipeline route with the assistance of Boots & Coots Special Services (BCSS) and Eagle Environmental (Eagle). The resources identified will include Longhorn, BCSS and/or Eagle, BCSS and/or Eagle emergency response subcontractors, and public resources. Response times will be calculated using a 50 mph travel time for response equipment. Full Response includes shut down of the pipeline, notification of applicable emergency response agencies, mobilization of response contractors with crews and equipment, mobilization of operator's employees in the area, "First Responder" on the scene of the suspected incident site, and initial deployment of response equipment.

Phase II:

Evaluate the identified resources and their ability to respond to the identified Sensitive Areas within 2 hours and Hypersensitive Areas within 1 to 2 hours. Response capabilities to fires will also be evaluated. Response times will be calculated using a 50 mph travel time for response equipment. Additional objectives of this evaluation will include:

a. Acquire the additional resources where needed.

b. Work with others to enhance our collective response capability.

ITEM 25:

WORK SCOPE
PUBLIC EDUCATION/DAMAGE PREVENTION PROGRAM

Longhorn shall implement a comprehensive public education/damage prevention program to educate the public and to prevent accidents resulting from excavation activities. The program will be designed to achieve the goals of:

- Widespread awareness of the importance of damage prevention;
- Contractor education, particularly those involved in excavation activities;

By conducting, at a minimum, the following activities:

- Annual meetings (not to exceed 15 months) with public officials, including local emergency planning committees, fire departments, local governments, and similar entities;
- Door-to-door visits with the public in areas adjacent to the pipeline in Tier II and Tier III areas every 2 years (not to exceed 30 months);
- Annual (not to exceed 15 months) mailings of educational brochures to all target audiences; and
- Annual (not to exceed 15 months) public service advertising and announcements.

The effectiveness of these programs will be evaluated on an ongoing basis. Appropriate modifications or additions will be made to improve the overall effectiveness of the public education/damage prevention program. See the Longhorn Pipeline System Integrity Program at Section 3.5.4.5.

ITEM 27:

WORK SCOPE
SECONDARY CONTAINMENT

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 with NFPA 30. This commitment shall be implemented prior to project startup. Confirmation of secondary containment provides redundant leak control capability.

Longhorn shall install secondary containment at the Cedar Valley pump station in Hays County (9609+60, MP182).

ITEM 28:

WORK SCOPE
ESTABLISH CONSISTENCY WITH AUSTIN RESPONSE PLAN AND USFWS RECOVERY PLAN

Longhorn shall ensure that its OPA '90 Facility Response Plan is consistent with the City of Austin's Barton Springs Oil Spill Contingency Plan and the USFWS Barton Springs Salamander Recovery Plan.

The Longhorn OPA '90 Facility Response Plan will be amended, when appropriate, to be consistent with the referenced City of Austin Barton Springs Oil Spill Contingency Plan and the USFWS Barton Springs Salamander Recovery Plan. As of this writing, the City of Austin plan is not available, and the USFWS plan remains in draft form. The present situation, in which the City of Austin and USFWS plans are under development, may offer opportunities to exchange information for the purpose of tailoring consistency during the development phase rather than after the respective plans are fully developed. Longhorn has initiated discussions with the City of Austin, and the parties have exchanged information directly related to establishing response coordination and consistency.

Based upon the presumed intent of this mitigation measure, to facilitate consistency among response efforts and the potential implementation of complementary response actions, consistency among the various emergency response plans would likely focus in the areas of response planning, release confirmation, notification and initial response, incident assessment, incident command, and containment and recovery.

This mitigation measure will be accomplished by expanding upon the coordination efforts involved with Mitigation Commitment 26, which requires more detailed response planning for "areas where high populations of potentially sensitive receptors are on or adjacent to [the] pipeline [right-of-way]." Longhorn will continue communication with both the City of Austin and the USFWS to identify opportunities to exchange information that will facilitate consistency in response planning.

ITEM 29:

WORK SCOPE
WATER QUALITY MONITORING

Longhorn shall provide funding for a contractor (to be identified by Longhorn, subject to OPS concurrence) to conduct water quality monitoring at each of the following locations in proximity to stream crossings of the pipeline to determine presence of gasoline constituents (e.g., PAHs):

<u>LCRA Region:</u>
Colorado River downstream of Cummins Creek
Colorado River downstream of Buescher State Park

Onion Creek downstream of Marble Creek
Barton Creek where it crosses into Edwards Aquifer Recharge Zone
Pedernales River downstream of Flat Creek
Sandy Creek downstream of Coal Creek
Llano River downstream of Marshal Creek
Llano River downstream of Gentry Creek
San Saba River downstream of Terrett Draw

Non-LCRA Regions:
Cypress Creek downstream of crossing
Brazos River downstream of Irons Creek
Pecos River downstream of crossing

A baseline will be determined by comparison to previous samples, and if elevated gasoline constituent levels are detected which could be attributed to the Longhorn pipeline, upstream sampling and sampling of contributing tributaries will take place to locate the source of the contamination.

ITEM 30:

WORK SCOPE
ALTERNATE WATER SUPPLY CONTINGENCY PLAN

Longhorn has developed separate contingency plans, to be implemented in the event of a pipeline release, to provide alternate water supplies to municipalities and to private water well owners along Longhorn Pipeline with sensitive groundwater resources. Longhorn Pipeline has developed the following program:

- For those wells or well fields in these communities that are identified as susceptible to contamination in the event of a pipeline release, a contingency plan has been developed that includes the following elements:

  Development of a spill response/remediation plan that will start cleanup procedures to prevent contamination from reaching a public water supply well.

  Identification and installation of a treatment system for any impacted wells that meets the requirements of TNRCC.

  Provision of an alternate water supply until any contaminated wells are remediated and meet state standards. The plan includes options such as shifting pumpage to other wells used by a municipality, or connecting to other water supplies that are in the area.

Public Ground Water Supplies Potentially Impacted by Pipeline:

- Aqua Water Supply Corporation (wells in Colorado River Alluvium downstream from Onion Creek, Dry Creek and Cottonwood Creek crossings, Carrizo/Wilcox Aquifer within 2.5 miles of pipeline)

- Bastrop (wells in Colorado River Alluvium downstream from Onion Creek, Dry Creek, and Cottonwood Creek crossings)

- Travis County MUD #2 (wells in Colorado River Alluvium downstream from Onion Creek crossing)

- Manor (buys water from Travis County MUD #2)

- Garfield W.S.C. (wells in Colorado River Alluvium downstream from Onion Creek crossing)

- Manville W.S.C. (Colorado River Alluvium downstream from Onion Creek crossing)

- Sunset Valley (Edwards Aquifer Recharge Zone)

- Eldorado (Edwards-Trinity Aquifer)

- Upton County W.S.C. (Edwards-Trinity Aquifer)

- Private wells receive similar treatment in a separate plan that has been developed to address private water wells that are susceptible to contamination in the event of a pipeline release. That plan includes the following elements:

  Identification of water wells along the pipeline route, as specified in the "Longhorn Pipeline Domestic Water Well Mitigation Plan." The water wells were identified on the basis of public databases and maps, to ensure that in the event of a release the well locations are known and protective efforts may be implemented immediately.

  Provision of early warning to area well owners in the unlikely event of a release that could impact their water wells.

  Hydrogeologic evaluation of the potential for contamination of area water wells in the unlikely event of a release that could impact water wells.

  Provision of temporary water supplies during development of either alternate water supplies or treatment technology to ensure a potable water supply is available to any impacted water wells.

  Development of a methodology to address the actual contamination of a water well, in the absence of a known pipeline release, that could be attributed to the Longhorn pipeline.

ITEM 31:

WORK SCOPE
SURGE PRESSURE ANALYSIS

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. Mitigation measures will adequately address any potential MASP problems on the system identified by the surge pressure analysis.

In response to the commitment to add check valves to the pipeline (See Mitigation Commitment 22), Longhorn performed an incremental surge pressure analysis which revealed that the check valves do not create any issues related to surge pressures.

ITEM 32:

WORK SCOPE
PIPE-TO-SOIL SURVEYS

Longhorn shall perform pipe-to-soil potential surveys semi-annually over sensitive and hypersensitive areas (which is twice the frequency required by DOT regulations – 49 CFR 195.416). Such surveys shall commence no later than 6 months after project startup and continue semi-annually (not to exceed 7 ½ months between inspections) thereafter. The surveys will provide frequent data about the ongoing adequacy of pipeline cathodic protection, and corrective measures will be implemented, as necessary, where indicated by the surveys.

ITEM 33:

WORK SCOPE
THREATENED AND ENDANGERED SPECIES
CONSERVATION MEASURES

Longhorn shall provide the necessary funding to establish an 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.

Longhorn shall provide $250,000 to the U.S. Fish and Wildlife service to be used to pay the cost of constructing a building for a captive breeding program and refugium for the Barton Springs Salamander. In addition, Longhorn shall provide $75,000 for equipment. Further, Longhorn will provide $55,000 (unescalated) to the Fish and Wildlife Service on an annual basis to pay for the cost of hiring and retaining a biologist to set up and operate the systems for maintaining the Barton Springs Salamander in refugium. The initial payment for building construction costs and equipment and the annual payments for the biologist shall be reduced by the amounts, if any, other parties contribute to pay such costs, and Longhorn's obligations to pay the costs for the biologist shall terminate if at any time in the future the Fish and Wildlife Service ceases to operate this facility as a refugium for the Barton Springs Salamander.

Timing of Implementation: Within thirty (30) days of start-up of the pipeline for the initial $380,000 payment and annually thereafter for the $55,000 payment.

In addition, pursuant to consultation with the U.S. Fish and Wildlife Service, Longhorn has committed to comply with certain conservation measures for the purpose of avoiding and minimizing the potential for adverse effects upon listed threatened and endangered species and their habitats, including the following:

Phase One:

- Identifying and marking habitat areas for avoidance.
- Planning project implementation to avoid or minimize the potential for adverse effects.
- Use of FERC-qualified environmental inspectors with authority to alter project implementation procedures in sensitive areas.
- Adjusting project timing to avoid breeding populations.
- Implementing storm water pollution control best management practices even when not required by permit.
- Maintaining qualified biologists in hydrostatic test project areas for immediate response in the event of a test water release in a habitat area.
- Avoiding, until project planning is accomplished, hydrostatic testing over the Edwards Aquifer recharge zone, portions of the contributing zone, and in Houston Toad habitat areas.
- Conducting additional species surveys along the pipeline ROW to determine actual presence or absence of species and populations.

Phase Two:

- Provision of additional conservation funding for the Houston toad.
- Detailed topographic and surface flow modeling to enhance spill response planning efforts (all species).

- Special investigative, preparation, and construction practices and techniques for pipe replacement over the Edwards Aquifer Recharge and Contributing Zones (Barton Springs Salamander) including:

    - Intensive geological and biological field studies of the pipeline corridor through the Edwards Aquifer Recharge Zone have been performed to identify sensitive features and areas, including ground penetrating radar and geotechnical coring, karst identification, geological and biological investigations of identified features, and detailed geologic assessment for recharge potential.

    - Use of enhanced best management practices for erosion and sedimentation control during and after construction of new pipe.

    - Sealing of subsurface voids encountered within limestone during trench excavation.

    - Installation of a colored, reinforced concrete barrier over the new pipe for enhanced protection from third party damage.

    - Grading and contouring of the surface over the new pipe installation to prevent surface drainage (potential surface release) from approaching identified sensitive areas/and features.

    - Selection of trench backfill material that creates high porosity under the concrete barrier for release retention capacity.

    - Construction of berms at locations where trench retention capacity could be exceeded.

- Identification of multiple emergency response locations in south Austin, southwestern Travis County and northeastern Hays County.

- Training for first responders and other spill response personnel for highest efficiency and care in species areas (all species).

ITEM 34:

WORK SCOPE
SURGE PRESSURE PROTECTION

Longhorn shall implement system changes, through system and equipment modification and/or observance of operating practices, to limit surge pressures 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, MP127.88 – 128.00 and 10489+47 –10490+00, MP198.66 – 198.67 and (b) installation of pressure activated by-pass systems at the Brazos, Colorado, Pedernales and Llano rivers. In the October 1, 1999 Mitigation Plan, Longhorn committed to replace one 671 foot section of pipe (Station Nos. 16992+41 – 16999+12, MP321.83 – 321.95) which was believed to contain several shorter sections of pipe characterized as Grade B. Since that time, Longhorn has identified file documents which confirm that the pipe is Grade X45 and not Grade B. Nevertheless, even though this pipe will not be replaced due to surge pressure concerns, it will be replaced pursuant to Mitigation Commitment 33 as a conservation measure resulting from Phase Two of Longhorn's consultation with the U.S. Fish and Wildlife Service. Replacement of the pipe reduces risk in areas of potential Houston toad habitat in Bastrop County.

In all cases when pipe is replaced pursuant to this Longhorn Mitigation Commitment 34, the sections will be replaced with new pipe installed in accordance with the description in Section 1.2 of this Mitigation Plan.

ITEM 35:

WORK SCOPE
LIMITATION OF MTBE CONTENT

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 will be incorporated into the Longhorn product specifications.

Trace amounts of MTBE and similar aliphatic ether additives could result from use of bulk storage tanks and other process equipment that previously contained products containing such additives.

ITEM 36:

WORK SCOPE
FUTURE ENVIRONMENTAL STUDIES

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 requirements as supplements to the Environmental Assessment of the Proposed Longhorn Pipeline System. For each such pump station, Longhorn shall submit the site-specific environmental study to the U.S. Department of Transportation no less than 180 days prior to commencement of construction.

ITEM 37:

WORK SCOPE
MAINTENANCE OF LIABILITY INSURANCE

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 cleanup in the event of a release of product from the Longhorn Pipeline System. The pollution Legal Liability Select policy form issued by American International Specialty Lines Insurance Company provides coverage for the following items:

- ♦ **Third Party Claims for Off-site Bodily Injury and Property Damage:** The policy will pay for loss related to Bodily Injury or Property Damage caused by pollution conditions on or under Longhorn's property which have migrated off premises. The Bodily Injury or Property Damage must occur beyond the boundaries of Longhorn's property. The policy defines **pollution conditions** as "the discharge, dispersal, release or escape of any solid, liquid, gaseous or thermal irritant or contaminant . . . into or upon land, or any structure on land, the atmosphere or any watercourse or body of water, including groundwater, provided such conditions are not naturally present in the environment." Property Damage, as defined in the policy, would include coverage for the remediation of a contaminated drinking water supply, and the provision by Longhorn of an alternative drinking water supply during the period of remediation.

- ♦ **Third Party Claims for On-site Bodily Injury and Property Damage:** The policy will pay for loss related to Bodily Injury or Property Damage caused by pollution conditions on or under Longhorn's property, if the incident which causes the Bodily Injury or Property Damage takes place on Longhorn's property.

- ♦ **Third Party Claims for Off-site Clean-up:** The policy will pay for **"cleanup costs,"** which are defined as "expenses, including reasonable and necessary legal expenses . . . in the investigation, removal, remediation including monitoring, or disposal of soil, surface water, ground water or other contamination" beyond the boundaries of Longhorn's property, resulting from pollution conditions on or under Longhorn's property which have mitigated off premises.

ITEM 38:

WORK SCOPE
PUBLIC ACCESS TO PIPELINE INFORMATION

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 relate 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.

ITEM 39:

WORK SCOPE
MODIFICATIONS TO MITIGATION PLAN

This Longhorn Mitigation Plan, and associated Pipeline System Integrity Plan and

Operational Reliability Assessment, shall not be unilaterally changed. The Longhorn Mitigation Plan may be modified only after Longhorn has reviewed proposed changes with DOT/OPS and has received from DOT/OPS written occurrence with the proposed modifications.

2. PROJECT DESCRIPTION

This Project Description describes the Longhorn Pipeline System. A detailed Project Description, which includes tables, figures and maps, is included in the Environmental Assessment.

2.1. System Description

The pipeline system covered under the Longhorn Mitigation Plan is made up of two distinct systems. The first system transports refined products from Odessa to El Paso, Texas and distributes product on four lateral pipelines. The primary refined product system with a capacity of 92,180 bpd is made up of the following two segments:

- A 29 mile, 8" pipeline from Odessa, Texas to a station in Crane County (Crane Station).
- A 237 mile, 18" pipeline from Crane Station to El Paso Terminal. Pumping units could potentially be added at an existing site called Cottonwood Station to assist with expansion of capacity.

There are four El Paso lateral pipelines, 9.4 miles, that connect El Paso Terminal to El Paso Junction (also known as the El Paso Laterals), with varying hydraulic surge system capacity.

- El Paso to Kinder Morgan, 12" - 104,400 bpd
- El Paso to Kinder Morgan, 8" - 36,000 bpd
- El Paso to Chevron, 8” – 48,000 bpd
- Kinder Morgan Flush Line, 8" - 50,400 bpd

The crude oil system with an initial capacity of 135,000 barrels per day is made up of the following segments:

- A 424 mile, 18" pipeline from Crane Station to Satsuma Station with the following intermediate pumping stations
    - Kimble County — Kimble County, TX
    - Cedar Valley — Hays County, TX
- A 32 mile, 20" pipeline from Satsuma Station to East Houston Terminal.
- A 9 mile, 20" pipeline from East Houston Terminal to 9th street junction.
- A 1 mile inactive and purged section of 20" pipeline from 9th street junction to Galena Park Terminal.

The pipeline system from East Houston South to 9th Street Junction has a system capacity of 360,000 barrels per day. The crude oil is delivered via the Longhorn South System to Magellan's Speed Junction where it is then further distributed to refineries and pipeline systems in the Gulf Coast Area.

With the addition of the following pump stations in 2013, the capacity of the crude system from Crane to East Houston Terminal is increased to 292,000 bpd:

- Texon
- Barnhart
- Cartman
- James River
- Eckert (existing scraper trap site)
- Bastrop (existing site)
- Warda (existing scraper strap site)
- Buckhorn
- Satsuma (existing scraper trap site)

Based upon shipper demand, Magellan may in the future make connection to third party facilities at the following locations:

- Texon - Reagan County, TX
- Barnhart - Crockett County, TX
- Bastrop - Bastrop County, TX
- Warda - Fayette County, TX
- Industry - Austin County, TX

Table 2.2 lists a chronology of overall pipeline actions leading up to the present.

Table 2.2 Chronology of Longhorn Pipeline Actions

1949-1950	Exxon constructed the 18"/20" pipeline, Crane to Baytown, to transport crude oil.
1950-1990	Operation and Periodic maintenance/refurbishment.
1990	An internal inspection (smart pig) of the 20" pipeline was performed
1995	An internal inspection of the 18" pipeline was performed
1995-1996	The 18" and 20" pipelines were subjected to a hydrostatic pressure test and purged with nitrogen.
Oct 21, 1997	Longhorn acquired the existing pipeline from Exxon.
1st Qtr. 98	Longhorn cleaned the existing pipeline to remove crude oil from the inner walls, so to prepare the existing pipeline for use in petroleum products service. Construction of new pump stations, terminals, and new pipeline sections began.
1998/1999	New Construction completion dates (dates shown are dates of substantial completion): Galena Park Origin Station – August 1998 Satsuma Pump Station – August 1998 Cedar Valley Pump Station – July 1999 Kimble County Pump Station – July 1999

	Crane Pump Station– March 1999 El Paso Terminal and Pump Station – August 1999 20" Pipeline, GATX to Tie-In to Existing 20" Pipeline, Houston – October 1998 18" Pipeline, Crane to El Paso – November 1998 8" Pipeline, Crane to Odessa – November 1998 (0.5 mile remains to be constructed to Odessa Meter Station) Odessa Meter Station – In design Cleaning and refurbishment of the existing pipeline 18"/20"- March to November 1998 Equipment installation remaining at a few sites Pipeline Laterals – In design (from El Paso terminal to tie-in point with three interstate pipelines)

3. SYSTEM INTEGRITY PLAN

3.1. Introduction

3.1.1 Longhorn Commitment to Pipeline System Integrity Program:

Longhorn Pipeline expressly commits to proactively identify, analyze, and manage the inherent risks associated with the operation of the Longhorn Pipeline and its associated assets. Longhorn intends this commitment to be made to the public at large, the communities along the pipeline path, the environment, potentially impacted flora and fauna, regulatory agencies, Longhorn's employees, third party contractors and suppliers, and Longhorn's investors.

Longhorn is committed to constructing, operating, and maintaining its pipeline assets in a manner that ensures the long-term safety to the public and to its employees, and that minimizes the potential for negative environmental impacts.

Longhorn, through its Longhorn Pipeline System Integrity Plan (LPSIP), is committed to the philosophy and proactive practice of the prevention of accidents.

Longhorn further commits to work collaboratively with all of its stakeholders, which includes the public and regulatory agencies, to optimize the opportunity for success of its LPSIP.

3.1.2 Risk Management

Similar to all pipeline systems, the Longhorn Pipeline assets have specific physical attributes that are characterized by its materials of construction and installation and by maintenance methods. The Longhorn Pipeline is further characterized by the products that it transports, its operating parameters, and its routing through a variety of population densities, land uses, and environmentally defined areas. Taken collectively, Longhorn Pipeline's physical assets, products transported and operating systems are factors that characterize the relative risks to the surrounding environment and areas of population. Physical data, collected by and contributed from an integrated team of operating, technical, and subject matter experts, is the cornerstone for the "Risk Management" process.

As an outcome of the Environmental Assessment process, Longhorn has benefited from significant input, recognized industry expert opinion, and detailed system assessments and evaluations. Specifically, the input of individuals and organizations such as Radian International, Kiefner and Associates, Inc., W. Kent Muhlbauer, the Office of Pipeline Safety (OPS), the Environmental Protection Agency (EPA), and LBG-Guyton Associates, specifically Charles W. Kreitler, Ph.D., has contributed to an enhanced understanding, identification, and appreciation of the potential risks and areas of sensitivity along the Longhorn Pipeline route. The Environmental Assessment process has resulted in the implementation of a number of specific risk mitigation initiatives, which are being incorporated prior to or following startup of the pipeline. The Environmental Assessment process and the accompanying mitigation initiatives establish the system integrity baseline for the Longhorn Pipeline. Further, Longhorn will evaluate the incorporation of the remainder of the Environmental Assessment information into its ongoing System Integrity Plan.

Longhorn will utilize a formal, relative risk assessment model to assist it in meeting the commitments to system integrity that were expressed in the previous section. For purposes of the LPSIP, "risk" is defined as: the product of (1) the probability, or likelihood, of an event, and 2) the potential consequences of that event.

The LPSIP has been carefully designed to gather unique physical attributes of the Longhorn Pipeline System assets, to identify and assess the risks to the public and the environment, and to actively manage those risks through the implementation of risk mitigation plans. The LPSIP, as the core organizational driver for Longhorn management initiatives and operational priorities, is charged with making improvements based upon system integrity analysis and performance metrics. The LPSIP also has responsibilities for resource allocation (time, talent, and money) targeted at risk mitigation.

Since the Longhorn Pipeline System traverses Texas from East Houston to El Paso and passes through a variety of unique areas of land use, topography, and population density, it likewise presents a variety of risk concerns to these lands and to the people who either inhabit or are present in these areas. Longhorn's relative risk assessment model divides the pipeline into logical segments which are individually analyzed for risk, and which subsequently ranks these segments using a relative risk sorting. Specifically, as a result of this process, the entire Longhorn Pipeline System has been categorized in accordance with the following designations: Tier I (normal cross-country pipeline), Tier II (sensitive areas), and Tier III (hypersensitive areas). Further, the area across the Edwards Aquifer in South Austin is a Tier III designated area of additional heightened environmental sensitivity that has resulted in even more scrutiny and the commitment to incremental risk mitigation measures.

Relative risk assessment allows Longhorn to target and focus on those pipeline segments posing the highest risk to population and/or environment, so to facilitate the development of risk mitigation programs. This enables the implementation of controls and measures with which to reduce the likelihood of adverse events or to mitigate the potential consequences. The inherent value in Longhorn's risk management approach to its LPSIP is that it ensures that its resources (time, talent, and money) are effectively employed in those areas of highest risk.

3.1.3 System Integrity Program Mission

Identify and manage risks associated with operating the Longhorn Pipeline System in a manner that ensures long term safety to the public and employees, and which minimizes negative environmental impacts.

Of critical importance to the success of its mission, the LPSIP is intended to function in addition and complementary to the base regulatory requirements of the U.S. DOT's RSPA Pipeline Safety Regulation, Title 49, Subchapter D, Part 195 (Transportation of Hazardous Liquids by Pipeline).

3.1.4 Areas of Emphasis

System Integrity is focused on two fundamental areas of emphasis in relation to the risk management process:

1. Current pipeline assets - Manage risks of Longhorn Pipeline assets. This includes the allocation of financial resources for a risk mitigation plan such as internal inspection and depth of cover initiatives.

2. Construction and rehabilitation projects - Mitigation of existing and minimization of future installed pipeline risks to the public and to the environment.

3.1.5 LPSIP Goals

1. <u>Effective</u>

- To function as an integral part of, and value added contributor to, our ongoing pipeline operations, construction activities, and business development processes
- To minimize accidents, and their consequences, on the Longhorn pipeline
- To help guide the allocation of resources to minimize our operational risks
- To identify all risks along the pipeline
- To enhance long term safety
- To educate and inform all stakeholders on identified risks
- To meet the intent of OPS, other governing and regulatory agencies, and additional Longhorn commitments

2. <u>Efficient</u>

- To mitigate risk with the highest benefit to cost ratio

3. <u>Adaptable</u>

- To adapt to change and unique requests
- To monitor, evaluate, and implement new technologies

4. **Continuous Improvement**

- To provide a method to confirm or improve the effectiveness, efficiency, and adaptability of the program by continuously measuring, evaluating, and upgrading the program.

3.1.6 Longhorn Risk Management Program Guiding Principles

Risk Management is a comprehensive management decision support process, implemented as a program, and is integrated through defined roles and responsibilities into the day-to-day operations, maintenance, engineering, management, and regulatory decisions of the operator.

1. Risk Management is a continuous process.

2. Risk cannot be completely eliminated.

3. Risk can be controlled through the cost-effective application of finite resources.

4. Risk Management increases, integrates, and enhances the value of information concerning pipeline safety.

5. Risk Management programs are structured but flexible, allowing customized approaches to be developed for specific issues and situations, encouraging innovation, and supporting continuous improvement.

6. The implementation of a risk management program should result in superior public safety and environmental protection.

7. Risk Assessments are critically dependent on the information requested and gathered from field operations through an open dialogue format.

8. Inclusion of operational and technical personnel into the System Integrity Program ensures accuracy and validates the results of the relative risk ranking results.

3.2. Longhorn Pipeline Management Commitment

Longhorn management will be responsible for providing the resources necessary to implement the LPSIP and will ensure that the program is executed in accordance with the "Process Elements" discussed in Sections 3.2.1, 3.3, and 3.4.

Longhorn will ensure its operations, maintenance, and improvement activities will be governed by an overall system integrity and risk management process through the adoption of this LPSIP. Longhorn further adopts the current mitigation plan contained in the Longhorn Mitigation Plan for all subsequent years of operations, as modified periodically by the Operational Reliability Assessment (“ORA”), conducted in accordance with Section 3.3, the Annual Third Party Damage

Prevention Program Assessment, conducted in accordance with Section 3.2.2.5, or other recommended modifications implemented in conjunction with OPS oversight and partnership discussed in this Section (collectively, the "Longhorn Continuing Integrity Commitment"). The Longhorn Continuing Integrity Commitment has been adopted by Longhorn for the express purpose of insuring that, over time, the integrity of the pipeline will be maintained and the environment will be protected at levels which are equivalent to those adopted by Longhorn at start-up of its pipeline, judged, at all times, by industry accepted and proven standards (as the same may change and improve over time).

As a proactive means to address the contributing factors of human error, Longhorn commits to expand its LPSIP to include formalized processes and programs which embrace and incorporate the elements of the Longhorn Integrity Management System (LIMS), Hazards and Operability Study (HAZOP), and Management of Change (MOC) processes. Through the integration of LIMS, HAZOP, and MOC into the LPSIP "Process Elements" (Section 3.4) and the Detailed Program Descriptions (Section 3.5), Longhorn commits to the installation, maintenance, and continuous improvement of its System Integrity Plan, which is further supported through performance based metrics and critical self-analysis.

Longhorn Pipeline commits to proactively share its self audit results and System Integrity Plan information with the Office of Pipeline Safety (OPS), and the information will be available to the public. Partnership with the OPS will ensure that Longhorn works cooperatively with the OPS in full keeping with the intent of the LPSIP, which will thereby improve Longhorn's opportunity to maintain and further improve upon the long term safety and overall integrity of its pipeline system. Partnership through the LPSIP is intended to further enhance the communication and information sharing between Longhorn and the regulatory agencies, which will lead directly to focusing resources on the most important threats and risks to Longhorn's immediate and long term pipeline safety. Longhorn fully endorses the following program goals:

- Enhance public safety and environmental protection by concentrating the deployment of Longhorn and OPS inspection resources to areas of greatest safety and environmental risk, and by addressing issues of mutual concern.
- Provide OPS with an enhanced understanding of Longhorn's entire system, including pipeline operation, maintenance, and emergency response programs. A more broad-based understanding of the Longhorn's integrity issues enables OPS to better consider and review with Longhorn the range of available integrity enhancements.

Longhorn Pipeline is fully committed to the active participation in and the proactive support of the State of Texas One-Call Damage Prevention Program (HB2295) for underground facilities. Longhorn further commits to stay abreast of regulatory and/or industry sponsored damage prevention programs. Longhorn has adopted the recommendations of the OPS sponsored "Dig Safely" (DAMQAT) and "Common Ground", One-Call Systems Best Practices Study Initiatives, and will require that its operator, contractors, and agents comply with same.

Longhorn management will employ, through its contract operator, a system integrity group that is technically competent and has demonstrated experience in pipeline operations and maintenance, technical support, risk identification, and overall management of mitigation measures and programs.

The System Integrity Group will be responsible for the following:

- Overall system integrity and risk management process
- Capital and maintenance funding oversight
- Incorporation of the management of change (MOC) process
- Development and distribution of system integrity status reporting centralization of pipeline attribute data
- Assessment and analysis of identified areas of risk
- Oversight and execution of the risk assessment model and development and maintenance of the relative risk assessment of the Longhorn Pipeline System
- Oversight of risk mitigation initiatives
- Capital and maintenance funding oversight and allocation of risk mitigation initiatives not related to routine operation and maintenance requirements
- Continuously evaluating new technology, new risk assessment processes, new mitigation processes and similar activities in a concerted effort to improve overall system integrity process

3.2.1 Longhorn Pipeline System Integrity "Process Elements"

The Longhorn Pipeline System Integrity Program consists of certain specific "Process Elements." The descriptions and program attributes of the Process Elements reflect action "over and above" those specified and required under various regulations and statutes, such as DOT's Title 49 C.F.R. Part 195.

Implementation of the "Process Elements" will ensure that Longhorn will effectively identify, analyze, and responsibly manage the most important threats to and risk of the Longhorn Pipeline System. The specific Process Elements are identified in Section 3.4 and are more fully described in Section 3.5.

As opposed to specific program descriptions and details on triggers for action within each program, the following information provides more of an overview of the general groupings and activities which comprise the LPSIP. Further, this information demonstrates the linkage between the various individual programs and the overall LPSIP.

3.2.2 Data Gathering and Identification and Analysis of Pipeline System Threats

1. The Longhorn Pipeline System Integrity Plan is specifically designed to identify, assess, and manage those elements and attributes that could lead to the inadvertent release of hydrocarbon products to the environment. The primary areas of focus include the following:

- An initial and ongoing assessment of the mechanical condition of the pipeline components
- An initial and ongoing assessment of controlling devices to ensure that operating pressures remain within safe parameters
- Internal analysis of product characteristics and protection efforts to eliminate issues of internal corrosion
- Mitigation plans to eliminate issues of external corrosion
- Third party damage prevention programs
- Analysis of potential impacts to pipeline integrity resulting from acts of nature, such as earth movement, water caused erosion, and flooding

2. LPSIP has two fundamental components. The first component includes a focus on the mitigation of Third Party Damages, Corrosion, Incorrect Operations, and Mechanical Design/Installation. The second component is a detailed segmenting of the pipeline with respect to population density, drinking water supplies, endangered species and recreation areas. The preparatory work performed and the information gained during the Environmental Assessment process, along with the resulting Tier I, Tier II, and Tier III segmentation, have provided Longhorn with a sharp focus on high relative risk areas along its corridor. Collectively, the analysis of these components results in an assessment of those conditions and forces which could possibly impact the integrity of the pipeline and its contained products. It also focuses resources to those areas that are the most sensitive.

Results of the initial and periodically updated LPSIP will be presented quarterly to Longhorn senior management and annually to the Longhorn Board of Directors.

3. The LPSIP analyzes the relative "likelihood" and "consequences," and asset integrity, within the categories identified in item 2 above. The two components, likelihood and consequence, allow for the targeted analysis of those potential occurrences that could have the greatest impact on the environment or the public in the event of a product release. With a heightened awareness of targeted physical areas, a "Scenario Based Analysis" will be performed to identify, assess, and manage associated risks.

4. The LPSIP incorporates the centralization and analysis of data collected through several distinct yet complementary programs. As pipeline attributes change, or as changes in environmental or population factors occur, the relative risk assessment model will be modified to ensure that the risk assessment process remains current and accurate. The relative risk assessment model also will be updated to reflect technological improvements and other sources of previously unavailable data.

Individual programs which contribute to the LPSIP risk assessment model include:

- Depth of cover surveys
- Population density surveys
- Land use and activity surveys
- One-Call activity levels surrounding the pipeline right-of-way easements

- Aerial patrol records, encroachment sightings, corrosion monitoring and maintenance program
- Internal corrosion coupon monitoring program
- Right-of-way condition monitoring and maintenance leak history reports
- Root cause analysis and incident investigations
- Cleaning pig reports and debris analysis
- Excavation reports and third party crossing line inspections
- Pipeline coating condition reports
- Metallurgical analysis of coupons
- Smart pig results analysis
- Third party pipeline crossing inspections and cathodic protection interference data
- GIS mapping information and participation with the OPS National Pipeline Mapping System (NPMS) Program
- Metallurgical analysis of corrosion coupons and pipe cut outs
- Metal fatigue analysis and pressure cycling operational data

5. Annual Third Party Damage Prevention Program Assessment - Longhorn Pipeline will consider the probability and consequences of third party damage as a component of its System Integrity Plan. Through the active monitoring of one-call activity levels, by area designation, across the pipeline system, coupled with population densities, environmentally sensitive areas, and the proximity of the pipeline to areas of public access (such as roads, parks, and other non-dwelling places of public gathering), Longhorn will annually assess the potential for inadvertent third party caused damages.

Data input to the Third Party Damage Prevention Program Assessment will include the tracking of the number of detected unauthorized ROW encroachments, changes in activity levels, changes in one-call frequency, physical hits, near misses, and repairs that occur along the Longhorn pipeline. Other key contributors to the assessment will include results data from internal pipeline inspection tools that are capable of identifying, locating, and qualifying pipeline dents, scrapes, and potential general third party caused pipeline damages in comparison with baseline attribute data.

Taken collectively, the Annual Third Party Damage Prevention Program Assessment process can initiate mitigation measures including the application of internal dent detection inspection tools, additional emphasis on the Damage Prevention Program, pipeline inspection patrol frequencies, public education programs such as Dig Safely, the further application of right-of-way encroachment programs, and other listed LPSIP Process Elements. The Annual Third Party Damage Prevention Program Assessment will be provided to the contractor developing the ORA to be incorporated into the recommended integrity analyses and recommendations.

Undetected third party damage to pipeline assets presents several risk elements that will be considered by Longhorn. In addition to the immediate and sometimes severe issues created through the complete puncture of the pipeline wall, Longhorn will also consider the longer term issues created through third party excavation activities that may be conducted near or around its pipeline assets. Relatively minor scrapes, scratches, dents and gouges to the pipeline metal wall or coating materials can lead to accelerated fatigue effects such as corrosion, crack propagation, or stress points. Even "non-direct" contact to the pipeline, such as through the inadvertent impingement of rocks against the pipeline, displacement of the pipeline against hard ditch walls, or the severing of cathodic protection wires, groundbeds, anodes, or cables can all lead to an accelerated loss of pipe integrity. Consequently, Longhorn will consider both the likelihood and the consequences of these types of occurrences in its Third Party Damage Prevention Program and in its overall LPSIP and ORA analysis. Longhorn will look for both positive and inferred indicators of these third party damages as part of its program.

One significant component of the Annual Third Party Damage Prevention Program is to consider the likelihood of "undetected" third party damages to the pipeline assets. Indicators of such damage potential includes:

- The number of times that ROW encroachments without prior notification are discovered through pipeline surveillance activities,
- A subjective sense of the respect and observance of one-call practices in areas along the pipeline by both the public at large and excavation contractors,
- The number of new third party pipeline damages that are discovered via internal or external pipeline inspections, the number of direct hits to the pipeline,
- The number of one-call reports (activity levels),
- One-call auditing process to provide feedback on the program effectiveness,
- Indications of "fresh" digging or excavation activity around the pipeline,
- The number of discovered pipeline coating damages,
- Unexpected changes in cathodic protection requirements and/or system performance,
- The number of foreign line crossings, along with a sense of the relative activity levels of these foreign lines in proximity to the Longhorn assets,
- Areas of seismic or heavy industrial activity in near proximity to the Longhorn assets,
- Aerial patrol and other surveillance reports, and
- Land use consideration, such as areas of cultivation, urban sprawl through commercial or housing developments, and roadbed or highway maintenance and construction activities.

The Third Party Damage attributes will be incorporated into the LPSIP, and by inclusion into the ORA, to further assist Longhorn and its third party consultants in the identification and recommendation of risk reduction mitigation measures. Further, inclusion of these attributes will allow for heightened awareness and sensitivity to those identified areas along the Longhorn corridor that appear to be more susceptible to third party damages. Heightened awareness and sensitivity will also provide guidance and input to possible increased public awareness education, increased surveillance activities, and emphasis on increasing pipeline markers. Results from Third Party Damage Assessment could also likely lead to recommendations for accelerated internal pipeline inspections or other investigative methods to assess overall pipeline integrity.

3.2.3 Integration of System-Wide Activities

The LPSIP will centralize and incorporate information and recommendations from the following individual programs, initiatives, or Groups:

- Pipeline Relative Risk Assessment Model
- Internal Corrosion Assessment
- External Corrosion Monitoring and Maintenance
- One-Call activity lists
- Field Operations gathered pipeline attribute data
- Operations Control Leak Detection Program
- Operations Control Operating Data
- Real Estates Services Group for third party encroachment management
- Engineering Assessment
- Safety, Environmental, and Training Services (SETS)
- Design Services
- Product Quality Control and Testing/Analysis
- Management
- In-line inspection program (smart pigging)
- Depth of cover program

3.2.4 Incorporation of Engineering Analysis

The LPSIP incorporates the following engineering analysis programs and attributes as input:

- "Pipeline Risk Management Manual," Second Edition, by W. Kent Muhlbauer
- Office of Pipeline Safety Pipeline Risk Demonstration Program
- Office of Pipeline Safety Integrity Inspection Pilot Program
- Damage Prevention Quality Action Team Program (DAMQAT)
- "Common Ground," One-Call Systems Best Practices Study
- Third party Industry Technical Consultants
- Vendor Literature
- Industry Trade Association Recommended Practices and Standards

3.2.5 Integration of New Technologies

System Integrity Group personnel regularly participate in industry and government sponsored technical conferences, which allows for an awareness and evaluation of developing technology and practices. Additional information is gained through the active participation and support of organizations such as API, AOPL, GPA, NACE, ASME, and ASCE. Many of these provide active support and financial aid to organizations including the Gas Research Institute and Batelle, which are routinely involved with the development of new technologies such as high resolution smart pigging and mechanical fatigue testing of pipeline materials. Further, reference to vendor literature and presentations and technical publications are other avenues used to stay abreast of developing system integrity technologies and methodologies.

3.2.6 Root Cause Analysis and Lessons Learned

The Longhorn Pipeline System Integrity Program incorporates a formal Incident Investigation Program (see Section 3.5.6) that includes analyses for root causes in actual and near miss events. Also included in the root cause analysis process are pipeline or system component repairs that are made to correct deficiencies or possible breaches in system integrity or reduction in maximum allowable operating pressure capabilities. The findings from the Incident Investigation Program are published and shared with affected Operations and Technical personnel, and are also integrated into the ongoing LPSIP analysis process.

3.2.7 Industry-Wide Experience

Resources for input to the LPSIP include information from Williams, the designated operator of the Longhorn Pipeline System. Williams brings information and programs from its operation of approximately 22,530 miles of Part 195 regulated hazardous liquids pipelines (9,170 miles refined products and 13,360 miles NGL). Additional information and experience is available from API and AOPL developed data and pipeline industry associations.

Additionally, Longhorn has access to pipeline operations, maintenance, and risk management practices from ExxonMobil and BPAmoco, which provides a forum for the sharing of data and risk management program experiences from these respected operating companies.

3.2.8 Resource Allocation

The LPSIP will manage the allocation and distribution of maintenance capital and asset integrity expense funding.

Dedicated maintenance capital and expense funding pools are managed through a relative risk assessment methodology that ensures that funding is targeted to maximize the risk mitigation objectives.

3.2.9 Workforce Development

As part of an ongoing educational and developmental process, system integrity presentations, newsletters and advisory bulletins shall be distributed, and workforce training and system integrity presentations shall be conducted under the advisement of the System Integrity Group.

3.2.10 Communication to Longhorn and Operations Management

System integrity presentations, newsletters, advisory bulletins, and workforce training initiative status updates shall be provided to the Longhorn Board of Directors. Risk mitigation initiatives and project funding plans shall be provided to the Longhorn Board of Directors at regularly scheduled meetings.

3.2.11 Management of Change

Longhorn has in place guidelines for monitoring and reviewing environmental, safety, and regulatory compliance requirements and associated risks when operational, business, and project changes occur.

Longhorn's Management of Change process is described at Section 3.5.7. This Management of Change program controls all qualifying changes in operation and maintenance practices.

3.2.12 Performance Monitoring and Feedback

The LPSIP will incorporate performance measures of program effectiveness through the scorecarding and analysis of incident rates, near miss occurrences, leak history, spill volumes, root cause analysis classification of incidents, service interruptions, quantity and associated costs of integrity initiatives, and categorization of integrity initiatives.

System Integrity Group performance measures and scorecard results shall be formally presented to Longhorn management on an annual basis. Quarterly performance updates shall also be distributed.

3.2.13 Self Audit

Longhorn will perform an annual self-audit of its LPSIP, with the intention of ensuring that stated plan goals, objectives, and commitments are being met. Longhorn also will perform a self-audit prior to implementing any throughput increase that requires the construction of new pump stations; the self-audit results will be shared with OPS, prior to implementation of the increase, and will be publicly available. Further, the Self Audit Process will provide the framework for overall LPSIP feedback and continual improvement.

3.2.14 Longhorn's Continuing Commitment

The Longhorn Continuing Integrity Commitment as described in Section 3.2 hereof has been adopted by Longhorn for the express purpose of insuring that, over time, the integrity of the pipeline will be maintained and the environment will be protected at levels which are equivalent to those adopted by Longhorn at start up of its pipeline, judged, at all times, by industry accepted and proven standards (as the same may change and improve over time). As part of the Longhorn Continuing Integrity Commitment, Longhorn has agreed to implement and be bound in the future by (a) the System Integrity commitments set out in Section 3.2 hereof, (b) the Mitigation Commitments described in Section 1.2 hereof, (c) the annual Operational Reliability Assessment described in Sections 3.3 and 4.0 hereof and (d) the required integrity verification procedures and remediation measures that will have to be implemented as a result such commitments and assessments. The results of these commitments will be incorporated into a formal relative risk assessment model similar to the one utilized in the Environmental Assessment process.

During the periods of time that Longhorn is implementing mitigation measures pursuant to the Longhorn Mitigation Plan, it will provide to OPS, and make available to the public, periodic reports setting out the status of mitigation commitment implementation and the results of mitigation-related studies and analyses. Additionally, Longhorn will perform an annual self audit of its System Integrity Plan for the purpose of ensuring that its stated plan goals, objectives and commitments are being met. The results of the annual self audit, including a relative risk assessment for the pipeline, will be shared with OPS and made available to the public. Further, Longhorn will submit periodic reports to OPS summarizing developments related to its Operational Reliability Assessment. These reports will be also made available to the public. Through the reports made available to the public, the public will be able to monitor Longhorn's continuing commitment to maintain the integrity of the pipeline at levels equivalent to those in place at start up.

Longhorn commits to maintain its relative risk assessment model with current up to date information and to make the results of that model available to the public as part of the reports described above. Longhorn considers this model to be an invaluable tool in the relative ranking of pipeline segments along its corridor. It needs to be noted though that the nature of the relative risk assessment model is that it results in an automatic decrease in scores over time. However, these decreases in scores have no direct relationship to a decrease in pipeline safety. Instead they provide a useful tool to analyze and prioritize maintenance, inspection and repair measures that will be implemented as part of Longhorn's Continuing Integrity Commitment, which measures will, in turn, raise the relative risk scores to levels consistent with the integrity baseline established for the pipeline at start up. Additionally, as pipeline attributes change, or as changes in environmental or population factors occur, the relative risk assessment model will have to be modified to ensure that the risk assessment process remains current and accurate. The relative risk assessment model also will have to be updated from time to time to reflect technological improvements and other sources of previously unavailable data. The modifications and updates to the relative risk assessment model that will have to be made over time will result in relative risk assessment scores in the future that will not be directly comparable to the relative risk assessment scores determined at the time of start up. Instead, Longhorn's continuing compliance with its Continuing Integrity Commitment will provide the best yardstick by which to measure the continuing safety of the Longhorn pipeline at levels equivalent to those in place at start up.

3.3 Longhorn Operational Reliability Assessment

Longhorn Pipeline will conduct an annual (not to exceed 15 months between assessments) ORA for its pipeline system (including physical pipeline, pump stations, terminals, and associated mechanical components). The ORA shall adjust integrity verification frequencies in response to changing uncertainties over time in response to environmental changes along the pipeline route and in response to data collected from integrity testing, additional attributes, changed attributes, root cause analysis results, or other programs identified in the LPSIP.

Although anticipated to be conducted on an annual basis, the ORA, or portions thereof as it relates specifically to any component of the overall Longhorn Pipeline System, may be conducted on a more frequent basis. Utilizing a methodology consistent with the overall integrity and risk assessment philosophy of the Longhorn Pipeline System Integrity Plan, triggering events such as major pipeline incidents, significant industry or agency advisories affecting pipeline integrity, or the advancement of new technologies that would result in dramatic reductions in pipeline risk or gained knowledge of mechanical attributes and component condition could lead to the initiation of an ORA at a more frequent interval. Other considerations for a more frequent ORA could include significant changes in pipeline operations, new or dramatic shifts to environmental issues, population shifts, or major reclassification of the activity level in areas around the pipeline assets, such as that caused by major construction or seismic induced stress considerations. Similarly, natural disasters such as flooding or ground movement faults that could jeopardize the integrity of the pipeline assets would also be considered in the evaluation for possibly increasing the frequency of the ORA.

The ORA expressly incorporates the Longhorn Continuing Integrity Commitment discussed in 3.2 above. By virtue of the incorporation of the Longhorn Continuing Integrity Commitment, the ORA shall clearly calculate changing risk over time and adjust integrity verifications in response to environmental changes over time along the pipeline route, considering all potential failure modes and contributing risk variables such as increasing activity levels, new buried utilities, any coating deterioration and other changes.

The ORA shall specifically include the results and data attributes of all internal inspection logs, close interval surveys, line condition reports, terminal and pump station inspection reports, product corrosivity reports, fatigue monitoring, and all other relevant system attributes, or other changes which would impact failure probability. Third party damage probability, based on the Annual Third Party Damage Prevention Program Assessment discussed in Section 3.2.2.5, will be considered when determining the recommended frequency of integrity verification inspections. The ORA results will include an assessment and discussion regarding the likelihood of both newly incurred and the growth/propagation of older existing external third party caused pipeline and coating damages. Further, the ORA shall make recommendations back through the process identified via the LPSIP in regards to third party damage mitigation and prevention initiatives.

The ORA is specifically intended to incorporate the results of all elements of the LPSIP as attributes and data to consider in the overall assessment of the mechanical condition of the Longhorn Pipeline assets. Further, any LPSIP or other initiated internal or external third party studies and evaluations, such as earth movement studies that may include specific areas such as landslide, erosion, scour and subsidence, will be made available to and incorporated into the ORA evaluation.

Surge analysis studies along with historical operating records of pressure peaks and cycles will be incorporated into and made a part of the ORA. For areas of potential and experienced surge pressures in excess of MOP in Tier I areas, the ORA shall consider the higher of surge pressures or MOP in determining the appropriate degree of scrutiny, evaluation, and resultant care in both the analysis process and the recommendations.

Longhorn will select and employ a reputable third party independent technical company, or companies, with demonstrated mechanical integrity/metallurgical pipeline and component analysis capabilities to perform its ORA assessment. Longhorn commits to select an ORA contractor(s) that will be subject to the review and the approval of OPS. With the approval of the OPS, Longhorn commits to implement the recommendations of the ORA based upon industry proven feasible methods of integrity verification required to timely implement proactive responses to prevent leaks and ruptures.

The ORA will provide Longhorn with an annual technical assessment of the actual effectiveness of the overall LPSIP. The ORA will also provide feedback on the adequacy, frequency, and additional element criteria of the evaluation plan, which includes use of internal inspection devices, hydrotests, and other mechanical integrity assessment and confirming processes and technologies. The ORA will also minimize risk degradation over time through ORA identified and recommended integrity verifications.

The ORA will proactively incorporate new and emerging technologies and processes that will assess and/or prove the integrity of the pipeline system. Employment of new and emerging technologies and processes, either in lieu of or incremental to existing known technologies, will be subject to the joint review and approval of OPS.

The ORA results will be factored back into the LPSIP, and will be integrated into the ongoing program.

As stated above, recommendations from the ORA, as identified by third party independent technical experts, with the approval of the OPS, will be implemented by Longhorn. Further, as ORA and LPSIP directed risk assessment and investigative activities and related mitigation initiatives are completed, updated data and pipeline attributes to Longhorn's formal relative risk assessment model (as identified in Section 3.1.2 of the LPSIP) will be incorporated into the model database. Longhorn commits to maintain its relative risk assessment model with current up to date information, and considers this model to be an invaluable tool in the relative ranking of pipeline segments along its corridor. The model allows for a multitude of investigative assessments that concentrate on specific attributes within the broader categories of Third Party Damages, Corrosion, Incorrect Operations, and Mechanical Design/Installation, and it is an excellent tool for "what if" and scenario based analysis. The model allows for perceived risks and threats to pipeline integrity to be proactively identified and evaluated. Coupling of the LPSIP commitments, the Longhorn Mitigation Plan (both initial and future identified initiatives), and the ORA recommendations and analysis, into the ongoing formal relative risk assessment model tool will enable Longhorn to honor its commitment to ensure the initial and long term integrity of its pipeline system. The net results of these efforts and commitments allow Longhorn to provide for the safety and protection of the public and the environment, and to provide a valuable service in the safe, effective, and economic transportation of motor fuels to Longhorn's direct and interconnecting market destinations.

3.4. A Synopsis of Longhorn's System Integrity Process Elements

Section 3.4 is comprised of summary descriptions of Longhorn's System Integrity Process Elements. Section 3.5 contains detailed descriptions of the Process Elements and the components of those Process Elements. These Process Elements, together with the Longhorn Mitigation Commitments, reflect Longhorn's commitment to human health and safety and the environment. They represent Longhorn's arsenal dedicated to the achievement of Longhorn's Pipeline System Integrity Plan Mission.

Briefly, Longhorn's System Integrity Process Elements include Longhorn's:

1. <u>Corrosion Management Plan</u>. Activities such as system surveys and evaluations, pipe design, coating selection and application, and cathodic protection are designed to maintain the Longhorn Pipeline System in a manner that ensures safety and environmental protection, with special attention paid to the discrete concerns associated with Tier I, Tier II and Tier III segments of the pipeline.

2. **<u>In-Line Inspection and Rehabilitation Program</u>.** Employing the best examples of current technology in a range of in-line inspection tools, Longhorn will have command of a 360-degree end-to-end look at the Longhorn Pipeline System and the benefit of a risk based system of re-inspection.

3. **<u>Key Risk Areas Identification and Assessment</u>.** With a keen awareness of concerns such as population density, environmental impact, land use and product characteristics, coupled with Longhorn's goal of mitigating threats to system integrity, Longhorn will maintain its focus on risk mitigation, analysis and management, drawing input from a variety of data sources.

4. **<u>Damage Prevention Program</u>.** Through a program of pipeline marking, aggressive surveillance, and multi-focused education, Longhorn is committed to mitigate the risk of injury to the public and the environment.

5. **<u>Encroachment Procedures</u>.** Ever vigilant to the possibility of potential or actual encroachments on the pipeline right-of-way, Longhorn acts decisively and responsibly in the exercise of its rights as an easement owner to ensure the maintenance of a clear and unobstructed right-of- way, which is crucial to the safe operation of any pipeline system.

6. **<u>Incident Investigation Program</u>.** Longhorn embraces a structure for incident investigations designed not to find fault or to posture for litigation but to find root causes so that preventive action may be taken to prevent recurrences.

7. **<u>Management of Change</u>.** Benefiting from an effective system for managing change, Longhorn is prepared to give full consideration to the operational basis of change through design review, risk assessment, team communication, and state of the art training protocols.

8. **<u>Depth of Cover Program</u>.** Structured to be a proactive program to mitigate risks to the public and the environment, Longhorn's ongoing Depth of Cover Program identifies and mitigates shallow or exposed pipe locations under dynamic circumstances, with special attention paid to sensitive and hypersensitive areas.

9. **<u>Fatigue Analysis and Monitoring Program</u>.** Through another proactive program, Longhorn identifies and mitigates any development of pressure-cycle-induced fatigue related cracking, considering in detail the risk of crack development on the basis of careful evaluation of data generated in the course of pipeline operations.

10. **<u>Scenario Based Risk Mitigation Analysis</u>.** Focusing on pipeline operations, maintenance and integrity, surveillance programs, and public education, Longhorn determines appropriate preventative measures and system modifications to reduce the risk of releases of product, on a pipeline segment by pipeline segment basis.

11. **<u>Incorrect Operations Mitigation</u>.** Longhorn scrutinizes the areas of potential human error (design, construction, maintenance and operation) and develops damage prevention strategies to counter potential human action or inaction.

12. **System Integrity Plan Scorecarding and Performance Metrics Plan.** Longhorn's commitment to system integrity is underscored by its dedication to specific program performance monitoring and continual improvement through a structure featuring its ongoing System Integrity Plan Audit, direct accountability, and regular reporting to the Longhorn Board of Directors.

Through these System Integrity Process Elements, and the Longhorn Mitigation Commitments, discussed in detail at Sections 1.2 and 1.3, the Longhorn Pipeline System Integrity Plan manifests its pre-occupation with its own good faith concerns for the protection and preservation of human health and safety and the environment.

3.5. Detailed Program Description of the Process Elements

3.5.1 Longhorn Corrosion Management Plan

1. Introduction

The intent of this plan is to outline the purpose and the operational concepts for corrosion control activities on pipelines owned by Longhorn.

Corrosion control activities such as, but not limited to, system evaluations; pipe design, coating selection and application; criteria for cathodic protection; and cathodic protection design, installation, operations, and maintenance are designed to mitigate corrosion and thus maintain the Longhorn Pipeline System in a manner that ensures long-term safety to the public and employees and that minimizes negative environmental impacts.

2. LPP's Commitment to Corrosion Control

All corrosion related activities are developed through sound corrosion engineering concepts and are applied under the direction of competent personnel trained in the field of corrosion control. These activities are governed by company policies and procedures and Department of Transportation Part 195 regulations, and are consistent with NACE International RP 01-69, ASME, and API recommended practices where applicable. The Longhorn Corrosion Management Plan is founded on the concepts that all applicable regulations and industry standards are met as a minimum, and going forward the focus will be compliance plus.

3. Risk Based Corrosion Management

A priority rating system based on relative risk assessment will be developed to select Hypersensitive and Sensitive areas where enhancements to the base line Corrosion Control Program will be developed and implemented. Corrosion related data will be processed in the overall System Integrity Plan to determine/modify the frequency of pipe to soil potential surveys, close interval pipe to soil potential surveys, rectifier inspection, foreign line crossing surveys, internal inspection, coating rehabilitation initiatives and other corrosion mitigation measures or new developing technologies.

4. Types of Corrosion Control Surveys

Longhorn will utilize the following corrosion related surveys:

- Pipe to Soil Potential Surveys
- Close Interval Pipe to Soil Potential Surveys
- Rectifier Inspection Surveys
- Foreign Line Crossing Surveys
- Atmospheric Inspection Surveys
- Exposed Pipe Visual Inspection Surveys (Internal and External)
- Internal Coupon Surveys
- Coating Surveys
- New Survey Technologies

5. Pipe to Soil Potential Surveys

Pipe to Soil Potential Surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the structure and in good contact with the soil.

These surveys will be conducted at pre-assigned test locations (ETS), cased crossings and above ground appurtenances.

All pipe to soil potential survey data will be recorded in the appropriate corrosion control database. Survey results and associated recommendations will be documented and made available to Longhorn management and the System Integrity Group.

6. Close Interval Pipe to Soil Potential Surveys

Close Interval Pipe to Soil Potential Surveys will be conducted by qualified personnel and under the direct supervision of NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the structure and in good contact with the soil.

Pipe to soil potential readings will be taken along the pipeline at approximately 3 foot intervals utilizing an eight-second on/two-second off frequency. Feedback from the surveys will be utilized to modify survey spacing requirements as necessary.

All close interval pipe to soil potential survey data will be recorded, and the information will be forwarded to the appropriate corrosion personnel for analysis.

Close interval pipe to soil potential surveys are typically triggered by annual pipe to soil potential surveys, internal inspection data, pipe inspection, or other related corrosion information or testing. In addition to these discrete corrosion data points, the LPSIP will initiate recommendations for close interval pipe to soil potential surveys based upon the overall relative risk assessment model. The relative risk assessment model can be influenced by population changes, environmental encroachments or other factors potentially affecting the overall integrity of the pipeline system.

Close interval pipe to soil potential survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, pipe inspection (excavation), or other testing or mitigation activities.

7. Rectifier Inspection Surveys

Rectifier Inspection Surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will include recording voltage, amperage, and kilowatt-hours (as appropriate). Voltage and amperage readings will be taken with a high impedance voltmeter.

All data will be recorded on the rectifier inspection form located inside the rectifier as well as forwarded to the appropriate Corrosion Technician for entry into the appropriate corrosion control database.

8. Foreign Line Crossing Surveys

Foreign Line Crossing pipe to soil potential surveys will be conducted by qualified personnel and reviewed by NACE certified corrosion personnel.

These surveys will be conducted utilizing a high impedance voltmeter and a copper/copper sulfate reference electrode placed as close as practical and directly over the pipe line crossing and in good contact with the soil.

Where bond test stations do not exist, additional voltage reading will be taken at 3 feet intervals either side of the crossing for approximately fifteen feet.

Where bond test stations exist, voltage and current drain data will be collected and the integrity of the bond confirmed.

Foreign line crossing pipe to soil potential data will be recorded in the appropriate corrosion control database.

Foreign line crossing pipe to soil potential surveys may be triggered by annual pipe to soil potential survey information, internal inspection data, pipe inspection data, foreign pipeline encroachment information, or other corrosion related information or testing.

Foreign line crossing pipe to soil potential survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, pipe inspection (excavation), or other testing or mitigation activities.

9. Atmospheric Inspection Surveys

Atmospheric Inspection Surveys will be conducted by qualified personnel, and the data will be reviewed by NACE certified corrosion personnel.

Atmospheric inspection data will be documented on the appropriate Atmospheric Inspection Form.

Atmospheric Inspection Survey information may trigger the need for pipe/coating rehabilitation, additional pipe inspection, system redesign, or other mitigation measure.

10. Exposed Pipe Visual Inspection Surveys

Exposed Pipe Visual Inspection Surveys will be conducted by qualified personnel, and the data will be reviewed by NACE certified corrosion personnel.

Exposed Pipe Visual Inspection data will be documented on the appropriate Pipe Inspection Form.

Exposed Pipe Visual Inspection Surveys may be triggered by annual pipe to soil potential survey information, internal inspection data, close interval pipe to soil potential data, foreign line crossing pipe to soil potential surveys, foreign pipeline encroachment information, or other corrosion related information or testing.

Exposed Pipe Visual Inspection Survey information may trigger the need for internal inspection, test station installation, coating rehabilitation, foreign line crossing surveys, further investigation to determine the extent of damage (if active corrosion is identified), or other testing or mitigation activities.

11. Internal Coupon Surveys

Longhorn Pipeline will address internal corrosion from both a product quality and integrity standpoint. Only pre-approved laboratories will be utilized for product testing.

Product samples will be tested every two months with a target of maintaining an "A" rating with respect to the NACE rust test (NACE TM 0172-93, "Determining Corrosive Properties of Cargoes in Petroleum Product Pipelines"). The corrosion inhibitor dosage will be adjusted in order to maintain this rating.

Baker Octel DCI-6A 80/20 corrosion inhibitor (or equivalent) will be injected at the pipeline origin at the GATX terminal. This inhibitor will establish a protective film on the pipe wall, and will protect the pipe against any water and/or corrodent in the product. The rate of injection will initially be 0.75 pounds per one thousand barrels.

Additionally, corrosion coupons are pulled, inspected, and analyzed for corrosion 3 times per year (not to exceed 4½ months between surveys). Target coupon corrosion rate is less than 1 mpy, with no pitting. Sample and coupon locations will be at El Paso terminal and Odessa station.

Pipeline pigging is done in order to clean the line of debris and water. This is beneficial to product quality and allows the corrosion inhibitor to establish a protective film on the pipe wall. Pigging is accomplished with cup/disc combination pigs, as well as brush pigs and TDW Pit Boss pigs. Williams – operated product lines are pigged twice per year.

Internal Coupon Surveys may be triggered by internal inspection data, product quality information, visual line inspections during project or maintenance work, or other data received regarding line conditions.

Internal Coupon Survey information may trigger the need for internal inspection, further investigation (if active corrosion is identified), inhibitor injection, product specification changes, or other mitigation measures.

Internal corrosion coupon data will be maintained in the appropriate internal corrosion coupon database.

12. <u>Coating Surveys</u>

Coating Surveys will be conducted by qualified personnel and under the direct supervision of NACE certified corrosion or coatings personnel.

These surveys will be conducted utilizing proven methods, such as close interval pipe to soil potential surveys and/or other technology such as direct current voltage gradient (DCVG) survey. State of the art equipment will be used, and surveys will be conducted in accordance with generally accepted industry practice. Surveys for disbonded coating utilize various technologies including the Pearson Survey.

All coating survey data will be recorded, and the information will be forwarded to the appropriate technician for analysis.

Coating surveys may be triggered by annual pipe to soil potential surveys, internal inspection data, pipe inspection, or other related corrosion information or testing. Findings of coating surveys will be incorporated into the LPSIP and the associated ORA.

13. <u>New Corrosion Related Technologies</u>

It is a primary responsibility of the Corrosion Control Department to identify, review, test, and implement applicable new corrosion related technologies.

Vendors, periodicals, conferences, and the like will be used as necessary to stay apprised of new corrosion related products and/or ideas.

Problems and/or inefficiencies may trigger the implementation or research into a new technology or process.

14. Corrosion Control Surveys - Frequency

- Pipe to Soil Potential Surveys

  Tier I – Pipe to soil potential surveys will be conducted annually (not to exceed 15 months between inspections) at pre-assigned test locations (ETS), including cased crossings and above ground appurtenances.

  Tier II & III – Pipe to soil potential surveys will be conducted semi-annually (not to exceed 7 ½ months between inspections) at preassigned test locations (ETS), cased crossings, and above ground appurtenances. The annual close interval survey will substitute for one of the semi-annual surveys in Tier III areas.

- Close Interval Pipe to Soil Potential Surveys

  Tier I & II – Close interval pipe to soil potential surveys will be managed through the relative risk assessment process within the System Integrity Model and conducted as necessary.

  Tier III – Close interval pipe to soil potential surveys will be conducted annually (not to exceed 15 months between inspections). (See triggers above for more information.)

- Rectifier Inspection Surveys

  Tier I, II & III – Rectifier Inspection Surveys will be conducted monthly (not to exceed 45 days between inspections) at each cathodic protection rectifier.

- Foreign Line Crossing Surveys

  Tier I, II, & III – Foreign Line Crossing surveys will be managed through the relative risk assessment process within the System Integrity Model and conducted as necessary. (See triggers above for more information.)

  In addition, interference bonds whose failure would jeopardize structure protection shall be inspected at intervals not to exceed six months.

- Atmospheric Inspection Surveys

  Tier I, II, & III – Atmospheric Inspection surveys will be conducted annually at pre-assigned above ground piping and facilities.

- Exposed Pipe Visual Inspection Surveys

Tier I, II, & III – Exposed Pipe Visual Inspection surveys will be conducted whenever a buried pipeline is exposed for any reason. A visual inspection of the internal portion of the pipeline will be conducted whenever any pipe is removed from the pipeline.

- Coating Surveys

Tier I, II & III – Coating surveys will be performed as dictated by pipe to soil potential surveys, close interval pipe to soil potential surveys, the relative risk assessment model, and the Operational Reliability Assessment.

15. Corrosion Control Surveys - Criteria and Remediation Schedule

A root cause analysis will be performed to identify both contributing causes and root causes of anomalies identified by any corrosion control survey. Such analyses, the findings of which will be incorporated into the LPSIP process, will assure that factors contributing to potential system deficiencies are counteracted on a permanent basis.

- Pipe to Soil Potential Surveys (including Close Interval and Foreign Line Crossing)

Tier I – Where practical a pipe to soil potential of at least -0.850 volts, at the pipe-to-electrolyte interface, with the protective current applied will be maintained. Potential drops other than those across the structure to electrolyte boundary will be considered by utilizing one or more of the following methods: measuring or calculating the voltage drops, reviewing the historical performance of the cathodic protection system, placing the reference electrode in close proximity to the structure, or interrupting the cathodic protection current source(s).

Where maintaining a -0.850 volt potential is not practical, a minimum of 100 MV shift of cathodic potential between the structure and a stable reference electrode shall be utilized. The information of polarization from native state or decay of polarization from the instant off potential can be used to satisfy this criterion.

Tier II & III – Where practical, a polarized pipe to soil potential of -0.850 volts will be maintained. During close interval surveys, potential drops other than those across the structure to electrolyte boundary will be considered by interrupting the cathodic protection current source(s) and recording the "ON" and "OFF" pipe to soil potentials. Once established, the "ON" potential and "OFF" potential will be utilized to correct future pipe to soil potential readings until such time as the system configuration or coating condition changes, or a new close interval survey is performed.

Where maintaining a -0.850 volt potential is not practical, a minimum of 100 MV shift of cathodic potential between the structure and a stable reference electrode shall be utilized. The formation of polarization from native state or decay of polarization from the instant off potential can be used to satisfy this criterion.

While no evidence exists that would indicate that excessive cathodic protection has caused damage to the external coating on the Longhorn Pipeline, the entire pipeline will be monitored for overprotection as well as underprotection. Cathodic protection system adjustments will be made, as necessary, to remediate any area of concern.

Overprotection will be monitored and minimized through the analysis of data from annual pipe to soil potential surveys, close interval pipe to soil potential surveys, and pipeline visual inspections. A practical value of -1.2 volts (polarized) in reference to copper/copper sulfate cell will be used as the value beyond which monitoring for overprotection shall be implemented.

<u>Tier I, II, & III</u> – Corrective action for noted deficiencies shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. All deficiencies will be resolved within one (1) year of discovery, except deficiencies of such a nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

<u>Casings</u>: During each cathodic protection survey, readings shall be taken at each cased crossing to detect any location where the carrier pipe may be shorted to the casing pipe. If the casing potential is within 100 millivolts of the pipeline potential, the casing shall be investigated to determine whether a metallic short to the carrier pipe is present. If a short is verified, a plan of action shall be developed within three months from the time of discovery. The practicality of clearing the short will be considered before any other measures are used. Action shall be taken to clear the short (a) in Tier I areas within six months of development of the action plan; and (b) in Tier II and Tier III areas within three months of development of the action plan.

In the interim, from the time a short is verified and action taken to clear the short, the location will be inspected for corrosion or the casing/pipe interstice may be filled with a high dielectric corrosion inhibiting material. During any interval that a casing has been determined to be shorted, the casing/pipe interstice will be monitored. Tier I areas will be monitored twice per year at intervals not to exceed 7 ½ months. Tier II and III areas will be monitored monthly at intervals not to exceed six weeks.

- Rectifier Inspection Surveys

<u>Tier I, II, & III</u> – Corrective action for noted deficiencies in rectifier operation shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. All deficiencies will be resolved within one (1) month of discovery except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

Rectifier outages are typically triggered by a natural event, such as a thunderstorm. A pattern or trend of rectifier outages will trigger a detailed analysis by NACE certified corrosion control personnel. This inspection will include the use of a multimeter and/or various other electrical testing equipment as well as visual inspection of the rectifier components. System enhancements identified during this analysis to mitigate against any such pattern or trend will be implemented as soon as practical, not to exceed six months.

- Atmospheric Inspection Surveys

Tier I, II, & III – Corrosion found during atmospheric inspection surveys will be evaluated using the RSTRENG Effective Area method.

Coatings will be evaluated during atmospheric inspection surveys utilizing ASTM D610/SSPC-Vis2 standard.

Corrective action for noted deficiencies found during atmospheric inspection surveys shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. Deficiencies relating to pipeline integrity will immediately be forwarded to “System Integrity”, “Engineering” and “Field Operations” for resolution. Deficiencies in external coating (paint) will be resolved within one (1) year of discovery except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

- Exposed Pipe Visual Inspection Surveys

Tier I, II & III – Corrosion found during exposed pipe visual inspection surveys will be evaluated using the RSTRENG Effective Area method.

Coatings will be evaluated during exposed pipe visual inspection surveys.

Corrective action for noted deficiencies found during exposed pipe visual inspection surveys shall be determined and completed immediately. Deficiencies relating to pipeline integrity will immediately be forwarded to “System Integrity”, “Engineering” and “Field Operations” for resolution.

- Internal Coupon Surveys

Tier I, II, & III – Internal corrosion coupon results will be evaluated 3 times per year (not to exceed 4½ months between surveys) utilizing the following guidelines:

	General Corrosion Rate (mpy)
Low	<1
Moderate	1.0 – 4.9
High	5.0 – 10
Severe	>10

Coupon corrosion rates over 1 mpy of general corrosion, or if pitting is observed, will trigger a detailed analysis directed by NACE certified corrosion control personnel. This analysis will include a review of incoming product quality sampling data, inhibitor injection rates, bacteria testing and, if necessary, inhibitor performance testing.

Corrective action for noted deficiencies found during internal corrosion coupon analysis shall be determined and completed as soon as practical, depending on the severity of the situation with respect to location of the pipeline and the potential for damage. Deficiencies will be resolved within six (6) months of discovery; except deficiencies of such nature they present a more urgent threat to pipeline integrity, in which case corrections will be done immediately.

Longhorn will use internal corrosion inhibitors to control potential internal corrosion, including microbial-induced internal corrosion. Coupons will be inspected for evidence of microbial-induced corrosion, and, if identified, responsive action will be taken to counter such potential.

16. Corrosion Control Documentation

- Data Storage

All pipe to soil potential survey, rectifier inspection, and foreign line crossing pipe to soil potential data will be recorded in the appropriate corrosion control database.

All close interval pipe to soil potential survey data will be recorded in a hard copy report as well as the appropriate electronic format (i.e., Bass, Excel, Lotus 123, etc.)

Atmospheric inspection data and exposed pipe visual inspection data will be documented on the appropriate forms and distributed appropriately.

Internal corrosion coupon data will be maintained in the appropriate internal corrosion coupon database.

- Reporting

All survey results will be submitted to the appropriate Longhorn representatives annually or as required on a project by project basis.

As a minimum these reports will include the survey data, a summary of findings, and recommendations to resolve any anomalies or implement changes.

- Roll up

Corrosion related data will feed into and be processed in the overall LPSIP by populating the appropriate portions of the relative risk assessment model.

3.5.2 In Line Inspection and Rehabilitation Program

1. <u>Introduction</u>

Longhorn has committed to an aggressive In-Line Inspection Program of its pipeline system. ILI provides a non-destructive 360-degree end to end look at a pipeline system. Longhorn will use this program to determine the physical integrity of its pipeline to ensure maintenance of the safest possible pipeline system.

2. <u>Longhorn's Commitment to Internal Inspection</u>

Longhorn is committed to internally inspecting the 18"/20" pipeline from Valve J-1 to Crane Station, within three (3) months of system startup, with a high resolution magnetic flux leakage (MFL) inspection tool, which is currently accepted as the best available technology for identifying corrosion and other metal-loss pipe anomalies. The MFL tool will also establish a baseline for implementation of the Operational Reliability Assessment. The frequency of future in-line inspections of the pipeline system, and the type of inspection tool to be employed, will be determined by Longhorn's Operational Reliability Assessment.

3. <u>Risk Based ILI Re-Inspection Intervals</u>

Hypersensitive and Sensitive areas of the pipeline will be primary selection criteria for the ILI re-inspection program. A priority rating system based on relative risk assessment will be developed to select future pipeline segments to determine re-inspection schedules. The frequency of re-inspections will be determined by previous inspection data along with fitness for purpose surveys which include corrosion growth models, leak history, monitored one-call activity, fatigue cycles, cathodic protection data, and current population and environmental status. A major factor that is included in the overall re-inspection frequency determination is the inclusion of the attributes of the Operational Reliability Assessment.

4. <u>Types of In-line Inspection Tools</u>

Longhorn will include the following as potential ILI tools that could be required by the ORA:

- High Resolution Magnetic Flux Leakage (MFL)
- Transverse Field Magnetic Flux Leakage (TFI)
- Ultrasonic
- Geometry/Sizing Tools

New ILI tools and inspection technologies will be incorporated into the program using a benefit analysis assessment.

A. <u>High Resolution MFL Tools</u>

This ILI tool will obtain an accurate indication of the corrosion condition of the pipeline by magnetically saturating the pipe in the axial direction as the tool passes down the line. The presence of corrosion, or any feature that changes the uniformity of the flux path, such as a third party strike or dent or other outside force damage, will cause some flux to leak out the pipe wall. The magnetic sensors detect this leakage and the data is collected along the pipeline for a full inspection run.

B. TFI Tools

The TFI tool will accurately detect hook cracks, lack of fusion, narrow axial external corrosion, dents with coincident cracks and gouges, and long narrow metal loss by magnetically saturating the pipe in the orthogonal direction as the tool passes down the line. Applying the magnetic field in a circumferential or transverse direction around the pipe, the tool can more easily discern defects orthogonal to that field. The presence of corrosion, or any feature that changes the uniformity of the flux path, such as a third party strike or dent or other outside force damage will cause some flux to leak out the pipe wall. The magnetic sensors detect this leakage and the data is collected along the pipeline for a full inspection run. The TFI tool examines both the pipe seam area and the pipe body.

C. Ultrasonic Tools

This ILI tool will locate laminations (potential hydrogen blister sites) and other three-dimensional metal loss features. By measuring the ultrasonic waves (time of flight) perpendicular to the pipe wall and collecting the data in a fluid medium, the tool can accurately determine the remaining pipe wall thickness and will indicate the location of dents, such as those caused by a third party strike or other outside force damage.

D. Geometry/Sizing Tools

Prior to running High Resolution MFL, TFI or Ultrasonic tools, Longhorn will run a sizing tool ("Dummy Tool") to ensure that the pipeline is fit to accommodate the passage of the inspection tool. If the "Dummy Tool" indicates passage problems, a geometry tool will be launched to locate and size the obstructions. MFL and TFI technology will detect dents in the pipeline. Although sizing of dents isn't within the MFL and TFI tool capabilities, any detection of dents will trigger a geometry tool run.

5. Running the Tool

In preparation for the specific ILI project, the project manager will write a detailed project scope and plan for the particular line section being inspected. This scope and plan will define in detail the actual line preparation, ILI tool sequencing, timelines and job duties for each and every line section involved in the ILI inspection. The ILI vendor, inspection personnel, and operations personnel will be familiarized with the details of the scope prior the execution phase of the project. The following provides a general overview of the ILI inspection process:

- ILI vendor will perform site survey and detailed review of line section (alignment sheets, length of segments, tool capabilities etc.).
- Select the appropriate ILI tool made of the correct composition, for the product being used as a medium to transport the tool.

- As necessary scraper traps are modified to accommodate the length of the ILI tool. This can be done by installing flanges and using extension barrels and/or permanently installing the traps. This may also include installing temporary traps at intervals not to exceed certain distances as protection against excessive cup wear and tool re-runs, and which provides for enhancement of data gathering capabilities.
- In-line inspection marker locations or some other reference point such as mainline valves or side bends must be surveyed for reference location.
- Verify the pipeline is fit and will allow the ILI tool safe passage (corrosion coupons, interface detectors, probes, and the like are removed to eliminate internal interference with the ILI tool).
- Line must be cleaned by means of cleaning pigs.
- Sizing (dummy) tool and/or geometry tool inspection must be performed prior to other ILI inspection tools being run.
- In-line inspection marker boxes must be placed over pipeline at predetermined reference locations.
- Load ILI tool in launch trap, assuring proper valve alignment.
- Launch tool, tracking it through in-line inspection marker and valve site locations.
- Receive and remove ILI tool.
- ILI vendor will download data from tool and verify successful tool run.
- Return traps to normal configuration.

6. The Analysis Process

- Preliminary Indications
- Phase I Investigation
- Vendor Final Report
- Phase II Investigation
- Features Discovered During Routine Maintenance
- Methods of Inspection and Repair
- Documentation

ILI technology is a rapidly developing field, and industry expectations include the development of ILI tools of greater accuracy than exists presently and with the capacity to identify a broader range of defects than is currently the case. As a result, present-day tools may not provide data that will allow precise identification of every inspection indication discussed in this section. However, Longhorn has included such indications in order to demonstrate the investigation criteria that should apply when those tool capabilities become generally available.

Preliminary Indications and Phase I Investigation

Longhorn requires that a Preliminary Report be provided by the ILI vendor. The following table presents categories of preliminary indications, corresponding response actions, and the time period within which the response action shall be initiated:

PRELIMINARY INDICATION	RESPONSE	INITIATION OF RESPONSE
Metal loss greater than 70% of nominal wall thickness, regardless of dimensions	Site inspection or excavation or other effective mitigation actions	Within 5 days of receipt of Preliminary Report
Top of the line dents (above 4 and 8 o'clock position) with any indicated metal loss	Excavation and repair, reduction in operating pressure by 20% (with concurrent resetting of pressure relief device setpoints), or other effective mitigation actions	Within 5 days of receipt of Preliminary Report
A significant anomaly that in the judgment of the data evaluator requires immediate action	Effective mitigation action that reduces the integrity threat posed by the anomaly	Within 5 days of receipt of Preliminary Report
Top of the line dents (above 4 and 8 o'clock position) without indicated metal loss and with depths greater than 6% of the pipe outside diameter	Excavation and repair, reduction in operating pressure by 20% (with concurrent resetting of pressure relief device setpoints), or other effective mitigation actions	Within 60 days of receipt of Preliminary Report
Cracks to the extent preliminary indications are an established TFI tool reporting procedure	Site inspection or excavation or other effective mitigation actions	Within 5 days of receipt of Preliminary Report

Vendor Final Report

The ILI vendor will provide a detailed and extensive final inspection report that will at a minimum contain these main features:

- Length, depth, and ERF (Estimated Repair Factor) of all detected metal loss defects as predicted by the analysis process; location, discrimination between internal and external defects and discrimination between metal loss and manufacturing faults.
- Cracks located in longitudinal ERW weld seam (TFI tool specific)
- The location of dents, gouges, and scratches and the presence of any associated metal loss
- The location and extent of girth weld anomalies such as cracks
- The location of eccentric or shorted casings and any associated metal loss
- The location of any foreign metal objects in close proximity to the pipe
- A listing of all nominal wall thickness changes
- A listing of all repair patches and sleeves
- A listing of all "hard" references and above ground marker devices, which have been used as location reference points

Phase II Investigation

The following table presents categories of indications which shall be investigated within 6 months of receipt of the in-line vendor final report; mitigation action, if necessary, will occur after evaluation by excavation:

INDICATION
Dents with any of the following: Metal loss, corrosion, exceeds 6% of the outside diameter, or

located in longitudinal seam or girth weld
Remaining strength of the pipe results in a safe operating pressure that is less than the current MOP at the location of the anomaly using a suitable safe operating pressure calculating criterion (e.g., B31.G, modified B31.G, RSTRENG or LAPA)
Casing shorts with associated metal loss
Girth weld anomalies
Corrosion within 3" of either side and/or across girth welds
Preferential corrosion of or along seam welds
Gouges or grooves greater than 50% of nominal wall
Cracks located in the pipe body, girth weld and longitudinal seam that are determined to be injurious to the integrity of the pipeline

Remaining indications shall be documented, and relevant information shall be integrated into the Relative Risk Assessment Model, as described under the heading "Documentation" in this Section 3.5.2.

The corrosion assessment methods identified above evaluate the likelihood that, based on the predicted depth and axial length of a corroded area or other flaw, the predicted failure pressure of the feature is less than the maximum allowed operating pressure. Features with failure pressures below maximum allowed operating pressure, as identified by the assessment criteria, will be chosen and prioritized for investigation. Crack-like defects will be evaluated by the vendor's data processing methods.

Upon excavation, the severity of an identified corrosion feature is assessed using the RSTRENG corrosion assessment criteria. Crack-like defects will be analyzed using external ultrasonic technology. Mechanical damage and or gouging will be assessed using ASME B31.4 recommended practices for pipeline repair.

<u>Features Discovered During Routine Maintenance</u>

Features discovered during routine maintenance activities will be addressed as they are discovered. The following features will be investigated upon discovery, and if necessary repaired:

- Corrosion exceeding 70% wall loss
- Corrosion areas shall be assessed based upon one or more of the assessment criterion (B31G, RSTRENG 0.85, or RSTRENG). Repairs or pressure reductions are required in the event that the MOP is greater than the calculated safe maximum allowable operating pressure based upon all of these assessment methods
- Corrosion exceeding 12.5% of the nominal wall thickness and within 1/2" either side of the longitudinal seam for ERW pipe and girth weld; B31G assessment criteria does not apply to corrosion in the girth or longitudinal weld or related heat affected zones per ASME B31.4. 451.6.2 Disposition of Defects
- Corrosion areas that are within a dent
- Corrosion areas that are within 3 inches of either side and/or across girth weld
- Dents in excess of 6% of the outside diameter
- Dents located in longitudinal seam
- Dents with associated metal loss

- Any indication with associated metal loss (gouges, scratches, third party damage, and the like)
- Severe mill related defects (lamination, hard spots, etc.)
- Girth weld anomalies
- Cracks located in girth weld
- Cracks located in pipe body
- Cracks located in longitudinal seam

Repairs will be made utilizing company standards and procedures which incorporate industry recommended practices. Prior to commencement of an actual repair project, a detailed project scope and plan for the particular line section being repaired will be developed.

7. <u>Methods of Inspection and Repair</u>

Investigation evaluations will be performed by qualified personnel. Each investigation, whether it results in a repair or not, is documented, and relevant information is incorporated into a database. Defects and features found by the ILI tools that require repair will be repaired utilizing the following methodology:

- Type A full-encirclement split sleeve in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Type B full-encirclement split sleeve in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Pipe Cut-Out and/or Pipe Replacement in accordance with the Longhorn Welding & Radiographic Procedural Manual and/or Maintenance Manuals
- Composite and or other new developing repair methods will be evaluated for appropriate utilization

Repairs will be made utilizing company standards and procedures which incorporate industry recommended practices. Prior to initiating the rehabilitation project, the project manager will write a detailed project scope and plan for the particular line section being rehabilitated. This scope and plan will define all of the components identified below, in detail, for each and every line section. The following process will take place upon the completed review of the final report:

1) Survey crew will stake dig locations in preparation for rehabilitation
2) Rehabilitation construction crew will ensure lines have been spotted correctly
3) Line pressure will be monitored prior to excavation
4) Crew will excavate line in accordance with OSHA regulations, including 29 CFR parts 1926.650 through 1926.652.
5) Ditch will be checked with hazardous gas monitor prior to entry
6) Coating shall be removed, and actual corrosion dimensions will be evaluated using RSTRENG assessment
7) Line pressure shall be monitored prior to welding
8) Repair Methodology: Type A or Type B full-encirclement split sleeve, Cut-Out and/or Replacement, or other new developing repair methods
9) Repair shall be allowed to cool and then be properly coated

10) Repair information is incorporated into permanent pipeline records

Documentation

The vendor supplied ILI report will be maintained on file for the life of the pipeline. All field inspection results and reports will be placed in a project book for permanent storage, and in addition the Pipeline Integrity and Corrosion Groups will maintain the vendor report for the life of the pipeline.

For each repair made to pipe, a record will be made and it will be kept for the life of the system. This record shall include the following: the date, location, and description of each repair; the nominal size, wall thickness, grade, mill test reports, and manufacturer of any pipe used for repairs. A copy of the record will be forwarded to the Manager of Data Resources. Technical Services shall register repairs on the alignment sheets or other appropriate maps and will provide copies to the appropriate Area offices. The following is a list of reports that will be maintained for the life of the pipeline:

1. ILI Report
2. Dig Sheet Report
3. Maintenance Report
4. Daily Reports (Project Work-Progress)
5. Welder Qualification Report
6. Daily Safety Meeting Reports
7. Contractor Drug Testing Report
8. Right-of-Way Reports
9. Mill Certification (MTR's) Report

Relevant data from the reports generated during investigations is maintained in a database. The data is used in support of, and incorporated into, the relative risk assessment process and the Operational Reliability Assessment.

The development of an Operational Reliability Assessment (ORA) involves a review of the current in-line inspection results in conjunction with subsequent excavations, cathodic protection data, corrosion growth models, previous internal inspection information, pressure cycle monitoring, coating type and condition, and metallurgical components of the steel pipe. The ORA is conducted annually using available information and the accuracy of the ORA is not dependent on new internal inspection every year. Thus, it is not necessary to conduct internal inspections every year for the purpose of conducting the ORA. The ORA provides additional data to the relative risk assessment model to facilitate a line specific maintenance plan. The ORA will assist in the determination of the timing of additional excavations and/or re-inspections (see ORA at Section 4.1).

3.5.3 Key Risk Areas Identification and Assessment

1. Objective

The objective of this program is to ensure that resources (time, talent, and money) are focused on those areas of the Longhorn Pipeline System with the highest identified or perceived risks. The results of this heightened focus typically include risk mitigation and/or risk management initiatives that directly lead to the reduction in likelihood or consequence of an unintended product release.

2. Areas of Focus

The Key Risk Areas Identification and Assessment Program is designed to focus on the following areas:

- Hypersensitive and Sensitive Areas
- Land Use
- Mechanical Integrity
- Physical Asset Attributes
- Product Characteristics
- Incorrect Operations
- Control Measures and Safeguards

3. Data Sources

The Key Risk Areas Identification and Assessment Program receives data input from a number of sources. Included among these are population density surveys, land use surveys, geological surveys to indicate areas of potential concern, topography, endangered flora and fauna surveys, physical attributes of the pipeline assets, transported product characteristics, operational parameters, and system controls.

4. Risk Identification

Collected data regarding the external and internal attributes of the Longhorn Pipeline System are loaded into the Relative Risk Assessment Model. The data sets are split into "segments", which allow for the grouping of similar internal and external pipeline attributes. The heaviest weighting for segmentation purposes is based upon changes in the surrounding population, the environment, or mechanical attributes of the pipeline. This approach allows for a targeted focus on those segments that would have the greatest impact to the public or to the environment in the event of an unintended product release from the pipeline.

The Relative Risk Assessment Model is designed to automatically prioritize and sort pipeline segments in accordance with their scored relative risk in relation to all of the other segments. Risk is defined as the product of likelihood and consequence, with the consequence factor increasing as population density or environmental sensitivity increases.

To date, the entire Longhorn Pipeline has been categorized into Tier I, Tier II, or Tier III areas. Tier I is identified as general pipeline routing with normal issues and concerns. Tier II is labeled as "sensitive" areas through which the pipeline is routed. Finally, Tier III is used to identify the "hypersensitive" regions along the Longhorn Pipeline. By way of specific example, remote regions of West Texas typically fall into Tier I with densely populated areas of Houston falling into Tier III, as do the environmentally sensitive areas over the Edwards Aquifer.

5. <u>Risk Analysis</u>

Following the identification of risk areas along the pipeline, the individual segments by prioritized Tier groupings are analyzed to determine if there are protective measures or mitigation methods that could reduce the likelihood of the occurrence of a negative event. This typically brings an analysis of operating parameters, third party damage prevention measures, public awareness programs, and available control measures and system safeguards, all of which lead to a pipeline system of higher integrity and overall risk reduction.

Enhanced risk mitigation measures, implemented as a result of the Relative Risk Assessment Model, in the areas of corrosion, third party damage and incorrect operations are discussed in the respective appendices relative to Tier groupings. Physical attributes describing the current system design and system condition were loaded into the Relative Risk Assessment Model and assessed against the progressively increasing requirements of Tier I, Tier II and Tier III areas. The specific mitigation measures outlined in the Longhorn Mitigation Commitments resulted in part from that assessment.

The results of the Key Risk Area Identification and Assessment Program are subsequently provided to the Scenario Based Risk Mitigation Analysis Program.

6. <u>Update Process</u>

As new information is made available, as population or environmental shifts impact the line segmentation, or following the incorporation of various risk mitigation initiatives, the Relative Risk Assessment Model is rerun to ensure that the risk identification and assessment model remains current and accurate.

The annual updating of population density and areas of environmental sensitivity results from a combination of aerial and land based surveillance patrol data collection.

3.5.4 Damage Prevention Program

1. <u>Objective</u>

The Damage Prevention Program is a comprehensive approach designed to educate the public and to prevent accidents resulting from excavation activities. Through cooperative efforts with excavators and the public, this program will achieve widespread awareness on the importance of damage prevention. The program will exceed current DOT Part 195 in the areas of permanent pipeline markers, ground and aerial surveillance, excavator education, public education, and line spotting activities to achieve uncompromising public safety.

2. Pipeline Markers

Permanent pipeline markers are used to notify the public of the general location of our pipeline. Permanent pipeline markers are maintained in Tier I (general), Tier II (Sensitive), and Tier III (Hypersensitive) areas as follows:

- Pipeline markers meet or exceed all requirements of 49 C.F.R. §195.410.
- Marker spacing for Tier I areas will be such that they are placed within line-of-sight of each other. Exceptions may be necessary for land use (i.e., cultivation), and landowner and tenant issues. Discussions explaining the importance of line markers, as identified in our Public Education program, will be held with landowners or tenants.
- Marker spacing for Tier II and III areas will be such that if any one marker is removed, the location of the pipeline can still be identified from either direction from any point in between.
- All line markers will be written in English and Spanish.
- Marker placement and density will be evaluated routinely through aerial and ground surveillance.
- Missing or damaged markers will be replaced within 7 days of discovery.
- Markers will be located at all aboveground facilities to identify the operator of the system.
- Markers will be located on each side of each public road crossing, water crossing, and railroad crossings.

3. Pipeline Surveillance

Most pipeline rights-of-way corridors are accessible through aerial surveillance, which is the primary method of right-of-way inspection and damage prevention. Periodic conditions such as weather, however, may render certain segments of the right-of-way inaccessible via fixed wing aircraft or helicopter and thus ground surveillance will supplement air surveillance. In addition, ground surveillance will be utilized when vegetation temporarily obstructs aerial surveillance.

Surveillance intervals will be as follows:

- Tier II and III areas: Every 2.5 days, not to exceed 72 hours
- Tier I areas: Once a week, not to exceed 12 days, but at least 52 times per year
- Edwards Aquifer Recharge Zone: Daily (one day per week shall be a ground-level patrol)

Aerial and ground surveillance frequency will be increased across Tier II (sensitive) and Tier III (hypersensitive) areas when the threat of flooding and/or severe erosion is identified near the pipeline right-of-way.

Emergency situations identified during aerial or ground surveillance will be immediately reported to the Longhorn Pipeline Control Center. All surveillance personnel and line spotters will be trained and certified in OSHA HAZWOPER to the first responder level.

Every consideration will be given to endangered species while conducting ground surveillance in and around the pipeline right-of-way. Maps depicting the location and habitat of endangered species will be utilized for this purpose.

4. Excavator Education

Excavator education is an important element of damage prevention in order to reduce the likelihood of unintended third party damage caused from excavation activity. The program focuses on promoting cooperation and awareness throughout the following groups:

- General contractors (i.e., irrigation, dirt, fencing, plumbing, landscaping)
- Land owners
- Real estate developers
- Utility companies
- Mining and quarry operations

The identified excavators will be provided with the following:

- Information on the "Dig Safely" program initiated by DAMQAT (Damage Prevention Quality Action Team - a joint industry and government effort to educate the public on the prevention of damages to all underground and submerged facilities).
- Information on the Texas One-Call system.
- Information about the location of the pipeline and products in the line.
- What to do in the event that unintentional damage of the pipeline occurs.
- Instructions on how to recognize and report a leak.

Direct mail flyers, written in English and Spanish, will include items such as dashboard calendars and stickers so that emergency contact information and "Dig Safely" information will be readily available. Reply cards will be included to measure the damage prevention program effectiveness.

Advertisements will be placed in various trade journals and/or community publications along the Longhorn right of way to reinforce the "Dig Safely" program and to instruct the excavators to use the One-Call system.

5. Public Education

Public education is an important element for insuring widespread awareness and cooperation to protect the public, property, and the environment. This program will utilize mailings and flyers, meetings to educate the local public, emergency responder meetings, periodic radio public service announcements, and newspaper ads.

Annual mailing to groups such as schools, residences, hospitals, churches, retirement homes and other businesses will include the following information:

- One-Call information
- Product identification information
- How to identify and report a suspected leak
- Personal safety guidelines in the event of a leak
- "Dig Safely" program information

Annual (not to exceed 15 months) mailings will target a one-quarter (1/4) mile radius of the pipeline in metropolitan areas and a one (1) mile radius in rural areas. Mailings will include items such as phone stickers, refrigerator magnets, and rulers to ensure that emergency contact information and "Dig Safely" information will be readily available. Door-to-door visits with the public in areas adjacent to the pipeline will be performed in Tier II and III areas every two years (not to exceed 30 months).

Damage prevention flyers, such as the "Dig Safely" program, will be distributed to the public at county fairs, trade shows, agricultural shows, feed and seed stores, home and garden shows, and equipment rental companies.

Non-emergency response government agencies that are exempt from one-call mandates, such as city and county planning, zoning and building permit offices, and agricultural agencies will be contacted annually (not to exceed 15 months) with mailings and a personal visit to distribute maps of the pipeline route and inform developers of the presence of the pipeline.

Reply cards and records of personal visits, along with third party damage incident scorecards, will be used to measure the effectiveness of the program.

Emergency response agencies within each county that the pipeline passes through will be contacted annually (not to exceed 15 months) in person and provided with maps of the system. Specific emergency response requirements and plans will be developed and reviewed on an annual basis with applicable LEPC and emergency responders. Annual emergency response drills will be conducted.

6. Line Marking and Inspection

Accurate line marking is an important element of damage prevention in order to reduce the likelihood of unintended third party damage caused from excavation activity. Line marking will include the following:

- When excavation is to occur within 50 feet of the pipeline, the line will be marked and a report of the activity will be submitted to the Area Maintenance Coordinator.
- When the pipeline is exposed due to excavation, a company representative will remain at the excavation site to inspect the work until there is no further threat of damage to the pipeline.

- Any time the line is exposed the relevant pipeline attributes will be recorded to evaluate the condition of the pipeline system. Information such as coating inspections, cathodic protection levels, and depth of cover levels will be measured and recorded and input into the Relative Risk Assessment Model.
- Prior to any road, highway or bridge construction, a technical review will be conducted to evaluate the associated stress to the pipeline, and to take any recommended protective measures to prevent consequential pipeline damage.
- Prior to any blasting near the pipeline, a technical review will be conducted to evaluate the impact of the blasting on the integrity of the pipeline and determine if a post-blast monitoring and inspection program is required. As appropriate, mitigation of potential damages caused by, or actual prevention of, proposed blasting activities will occur based upon technical review and recommendations.

3.5.5 Encroachment Procedures

1. <u>General</u>

Longhorn's primary mission is to ensure:

- Encroachments do not hinder the ability to safely operate and maintain the assets
- Pipeline adjustments are designed in accordance with sound engineering judgement to ensure compliance with governing regulations.
- The respective rights and privileges in the easements are maintained.
- Proper reimbursement for work performed.

An encroachment is any infringement on the pipeline and associated rights-of-way. An encroachment is any activity or structure that interferes with or impedes the pipeline(s) or easement rights.

2. <u>Introduction</u>

The maintenance of a clear, unobstructed right-of-way is critical to the safe operation of any pipeline system. Encroachments not only obstruct the system from observation, but also introduce additional activities over the pipeline assets. As such, it is the responsibility as the owner of certain easement rights to protect them. It is necessary to watch for and take appropriate protective action against any potential or occurring encroachments. In all cases, the need for early reporting and documentation of encroachment issues is vital to the integrity of the rights and eventually the pipeline systems.

Protecting the right-of-way from encroachments is of major importance to daily operations. Every employee must be concerned about encroachment problems. We should not allow encroachments that would interfere with the legal rights and obligations.

These guidelines provide general procedures for handling encroachments. Consideration for appropriate protective action against such potential encroachments should be high priority.

3. <u>Interoffice Procedure</u>

Pipeline representatives that observe or hear of an impending or in-progress encroachment should notify the responsible Real Estate Services Representative and Coordinator of Operations and Maintenance (COM). The COM will gather information pertaining to the encroachment.

Since different easement forms have been utilized and subsequently modified and amended, familiarity with the extent of the rights in one easement does not assure familiarity with any other easement. Prior to contacting the encroaching party, the information gathered above should be relayed to the respective Real Estate Services Representative in order to review the specific easement rights across the subject property. The Real Estate Services Representative will make the COM aware of these rights.

The Real Estate Services Representative may make the initial contact to advise the encroaching party of the steps necessary and the basic details of what will be allowed within the right-of-way. The assigned Engineer and/or the COM will discuss with the encroaching party their proposal for resolution of the encroachment.

Once the details have been worked out, determination of the appropriate written agreement to be entered between Longhorn and the encroaching party must be determined.

Example forms may include:

- Pipeline Location and Encroachment Permit
- Short Form Encroachment Permit
- Reimbursement Agreement
- Encroachment Agreement

For encroachments having an impact to the facilities, the Real Estate Services Representative will prepare Encroachment and Reimbursement Agreements based on information and required restrictions given by the Engineer and/or the COM. Said encroachments should be submitted to the Real Estate Services Representative who will, in turn, put together the necessary agreement to be jointly executed by the landowner or encroaching facility owner (Owner) and Longhorn.

3.5.6 Incident Investigation Program

1. <u>Introduction</u>

This program includes guidelines for conducting incident investigations. The guidelines specify what constitutes an incident, when the investigation is to begin, who is to participate in the investigation, the preparation of the Incident Investigation Report and the criteria for conducting an incident report review and critique.

2. Purpose

The purpose of this program is not to find fault, but to identify and understand why the incident took place in order to prevent recurrences.

3. Scope

This program applies to all pipeline assets, and terminals owned by Longhorn.

4. Definitions:

Accident - An undesired event that results in harm to people or damage to property

Near-Miss - An undesired event which, under slightly different circumstances, could have resulted in harm to people or damage to property.

Incident - Includes accidents, near-miss cases, or repairs, and/or any combination thereof

Major Incident - Includes events which result in:

- A 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

Significant Incident - Includes events which result in:

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

Minor Incident - Includes events which result in:

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

Repair – 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.

5. Classifying Incidents

Incidents are normally classified as major, significant or minor. However, it is possible that an incident could be a combination. A specific scenario of a minor accident (minor actual loss) could also be a major near-miss (major potential loss).

Furthermore, root cause analysis (see Overview, below, and Section 3.2.6) classifies the causes of repairs as an analytical step. Such classification enables the analyst to eliminate potential causes, which in turn adds precision to the identification of root causes and contributing causes as well as trends that may require mitigation. An example of a classification of potential causes follows:

- Corrosion
  - Atmospheric
  - Internal
  - External (buried pipe)

- Incorrect Operation
  - Design
  - Material Defect
  - Joining
  - Operations Control
  - Field Operations

- Third Party Damage
  - Depth of Cover
  - Public Education
  - Patrol
  - Right-of-Way Condition
  - One-Call

- Design
  - Hydrostatic Test Failure
    - Internal Corrosion
    - External Corrosion
    - Material Defect

6. Overview

The ultimate aim of an incident investigation is to reduce the likelihood of accidents, near-misses, and the need for future repairs. However, there are several other aspects of the investigation process that provide value to the company and employees, such as:

Preventing recurrences

Complying with policies and regulatory requirements

Maintaining employee awareness of the importance of safe work habits

Prevention is the primary reason for conducting an incident investigation. Unless the unsafe acts or conditions that caused the incident are identified and eliminated, or at least controlled, the possibility remains that similar mishaps will occur. Additionally, government regulations may require a formal investigation of some kinds of accidents, especially those resulting in fatalities, serious injury, environmental harm or substantial property damage. LPP commits to investigate "close calls" or "near-misses". A near miss will be considered an accident that didn't happen. Its causes have to be identified and eliminated; otherwise, the next near miss could result in a serious accident. Similarly, repairs made to the pipeline or its system components will be investigated to determine the root cause that led to the needed repair. Understanding what caused the conditions that led to the repair, and the proactive application of the information gained from the investigation process, should directly lead to a reduction in future related incidents, near-misses, or similar natured repairs.

Initial incident investigation and reporting is usually the responsibility of field operations where the incident occurred; however, they are not the only ones involved. Team members should be selected based on their training, knowledge and ability to contribute to an effective investigation. The investigation team must consist of a minimum of two people, of which at least one person is knowledgeable in the process involved, including contract employees if the incident involved work of the contractor, and another person/s with appropriate knowledge and experience to investigate and analyze the incident thoroughly. The incident investigation team must begin the investigation as promptly as possible, but not later than 48 hours following the incident.

An investigation report must be prepared and distributed. After the report is reviewed, the final report, resolutions and corrective actions will be distributed to all affected personnel relevant to the incident findings (including contract employees when applicable) and a copy sent to the Incident Investigation Program administrator.

Each incident investigation has the potential to be different and must be managed accordingly.

7. **Incidents Requiring Investigation**

The incident investigation program is required to utilize a three-tiered approach for investigating all incidents meeting the definition of minor, significant, and major incidents. The three-tiered approach promotes expending a variable effort in conducting investigations based on an assessment of the incident's actual and potential loss. Small leaks such as valve packing leaks or pump seal leak off are considered nuisance leaks and should be addressed during regular maintenance and repair activities. However, nuisance leaks would be investigated if they fell in to the near-miss classification. Serious incidents warrant a more comprehensive team investigation. If appropriate, the investigation is to be conducted under the direction and control of LPP legal counsel.

3.5.7 Management of Change

1. **Longhorn Commitment and Program Objective**:

At the commencement of operations, Longhorn will implement a management of change process. The objective of the program is to establish a policy and procedure for managing changes that affect process chemicals, technology, equipment, procedures and facilities across the Longhorn Pipeline System.

2. **Policy**

To ensure that any changes in the program chemistry, technology, equipment, procedures and facilities, excluding "replacement in kind," are addressed prior to implementation or start up of the proposed change.

3. **General Discussion**

- The Management of Change process requires that all temporary and permanent changes and modifications require approval by the individuals responsible for the maintenance, operation and engineering aspects related to the change.
- The Management of Change process requires that all changes be evaluated using an appropriate hazard analysis (HAZOP, what if, etc.) and that the change be risk assessed to ensure that the appropriate risk mitigation levels are maintained on the system.
- The amount of time a temporary change will be in effect must be agreed upon and approved by those assigned review and approval responsibilities.
- A list of all temporary and permanent changes including expiration dates shall be maintained at the appropriate local field office.
- All documents and files affected by the change (O&M procedures, P&ID's, instrumentation and electrical drawings, emergency procedures, equipment specifications, training materials, etc.) must be identified and revised as necessary on a timely basis.

4. Responsibilities

Longhorn senior operations management, through Williams senior operations management, will ensure that an effective program for managing change is in place. An "effective program for managing change" is herein described as having the following attributes:

- Full consideration of the operational basis of the change
- Revision to the affected process information (O&M procedures, P&ID's, equipment lists, etc.)
- Design reviews, risk assessment, communication of change training
- Pre-start up reviews

Longhorn will require Williams to be responsible for:

- Ensuring that identified safety and health hazards created by changes are eliminated or controlled through engineering, administrative and/or personal protective measures.
- Ensuring that the impact of the change has been assessed by the Systems Integrity Group to verify that the change has been evaluated to determine that total system risk has been considered in terms of the change and that appropriate risk mitigation measures have been implemented concurrent with the change as appropriate.
- Establishing approval levels for authorizing change requests.
- Ensuring that change requests and supporting documentation packages are adequate for the change and have been properly reviewed, approved and tracked to completion.

3.5.8 Depth of Cover Program

1. Objective

The objective of the Depth of Cover (DOC) Program is designed to proactively identify areas of shallow or exposed pipe along the Longhorn Pipeline System. Secondly, through a formalized DOC Mitigation Process, this Program intends to manage the associated risks through a variety of methods, all designed to reduce the likelihood of unintended outside force damage and consequential damages to a defined level.

2. On-Going Program

The DOC Program is designed to be an on-going initiative. Land use, population density, environmental issues, and changes to the absolute coverage of the Longhorn Pipeline are expected to change over time. Consequently, DOC data will become outdated as new subdivisions are built, as changing patterns of land erosion occur, and as topsoil is generally moved over time as a result of wind, water, and mechanical forces.

3. Relative Risk Assessment Approach

Similar to many other System Integrity Group initiatives, the DOC Program is designed to prioritize those areas of highest relative risk. The investigative and resulting mitigation processes will consequently focus on the defined areas of hypersensitive (Tier III), sensitive (Tier II), and other (Tier I), in descending order. Further, as the defined classifications are modified over time due to changing population and environmental concerns, so the DOC prioritizations will be modified.

4. Program Elements

The DOC Program is structured in four governing categories: Identify, Notify, Protect, and DOC Risk Mitigation/Management. Further description of these categories is provided below:

- Identify:

Timely identify through aerial patrols, operational activities, public input and other means target areas requiring DOC surveys based upon land use, environmental concerns, population density, and construction and excavation activity levels.

Prioritize the targeted areas in accordance with Tier III, Tier II, and Tier I classifications.

Conduct DOC surveys to identify areas of shallow and exposed pipeline facilities.

For areas of shallow or exposed pipe, quantify the associated depths and lengths.

NOTE: Shallow pipe is herein defined as either (a) being within the physical interference level of the normal land use within the prescribed pipeline segment routing or (b) being at a depth that may not continue to provide adequate protection in light of changing population densities and/or environmental concerns. An example of the first type of shallow pipe would be a pipeline in a cultivation area with twenty four inches of cover that is periodically plowed to a thirty inch depth. An example of the second type of shallow pipe is pipeline in an area being developed for a new subdivision where the building of roads, the installation of utilities and the construction of new homes will require "pipeline adjustments." Pipeline adjustments are reasonable and prudent measures undertaken to ensure that the existing and reasonably anticipated land use and environmental sensitivity of the area under evaluation can safely coexist with the pipeline facilities that are in place. Pipeline adjustments will include, but not be limited to, pipeline lowering, pipeline replacement, installation pipeline protective devises, increased patrols and/or increased signage.

- Notify:

Report findings to System Integrity Group and Field Operations.

Notify landowners and/or tenants of potential areas of concern.

Communicate with developers and local authorities to ensure an appropriate awareness of the location and risks of the pipeline and to coordinate appropriate pipeline adjustments in anticipation of and in connection with construction and development activities.

- Protect:

Formally notify impacted developers, contractors, local land use authorities, landowners and/or tenants via certified letters with detailed mapping and description of areas of concern.

Enhance pipeline warning markers as deemed appropriate.

Develop pipeline adjustments that are reasonable responses to changing conditions.

- DOC Risk Mitigation/Management:

Evaluate appropriate pipeline adjustments.

Select preferred risk mitigation or risk management method.

Allocate funding as appropriate.

5. DOC Program Prioritization Guidelines

The DOC Program, along with its resulting mitigation initiatives, will be prioritized in accordance with the following guidelines. Process flow diagrams, labeled as "Longhorn Prioritization for Exposed Pipe" (Figure 1), and "Longhorn Prioritization for Shallow Pipe" (Figure 2) are attached hereto.

- Priority 1 Items – Immediately develop and execute a corrective action plan
- Priority 2 and 3 Items – Risk assess/prioritize, and develop and execute a corrective action plan
- Priority 4 Items – Continue monitoring

Examples of priority items are described on Figure 1 and Figure 2.

Any pipe replaced will be installed as described in Section 1.2 of this Mitigation Plan.

6. **<u>Data Management and Initiative Implementation</u>**

Data initially obtained and periodically updated via the DOC program will be centralized and maintained in a formal database. The System Integrity Group will utilize the DOC database as an input to its overall risk management process, which includes the relative risk assessment process and the ORA. (See, also Section 3.5.8.3 above).

The System Integrity Group will further manage the recommendation and funding process associated with the implementation of DOC mitigation initiatives.

7. **<u>DOC Relative Risk Assessment</u>**

The relative ranking of identified DOC line segments are assessed in accordance with the following:

Relative DOC Risk = Land Use Index + Population Index + Environmental Index
+ Cultivated Index + Creek/Water Index

3.5.9 Fatigue Analysis and Monitoring Program

1. **<u>Objective</u>**

The objective of the Fatigue Analysis and Monitoring Program is to perform an initial and ongoing assessment/analysis of the potential and likelihood of the Longhorn Pipeline System to develop pressure-cycle-induced fatigue related cracks. The Program is also intended to proactively prevent any fatigue related incidents and consequential damage to the public or the environment through the avoidance of operating in a manner that would exacerbate the formation of cracks, and through the early identification and mitigation of newly developing cracks or the growth of existing cracks.

2. **<u>Analysis Process</u>**

Longhorn will commission pipeline industry recognized third party pipeline metal fatigue experts, such as Kiefner and Associates, Inc., to perform annual pressure-cycle-induced growth of crack metallurgical analysis on the Longhorn Pipeline System. The analysis process will incorporate the attributes of the Operational Reliability Assessment.

3. **<u>Operator Supplied Information</u>**

On an annual basis, Longhorn will supply the contracted analysis firm the following information:

A schematic of the line sections to be analyzed, showing annual operating pressures, nominal pipe diameters, wall thickness, and yield strength data.

Identification of sensitive (Tier II) and hypersensitive (Tier III) Longhorn pipeline segments to ensure a heightened awareness and closer scrutiny of the pipeline assets located in these areas.

4. Contractor Provided Information

The selected pipeline metal fatigue contractor will be requested to provide Longhorn a report that will include the following information:

- All inputs and assumptions made or used in the pressure-cycle-induced growth of crack analysis/assessment program.
- A schematic of the line sections that were analyzed, showing operating pressures, nominal pipe diameters, wall thickness, and yield strengths.
- Graphs showing failure pressure as a function of crack size and crack growth over time.
- A summary of the results of the analysis.
- A recommendation of any mitigation methods or corrective action to be taken, including recommended changes in operating pressures, to ensure the safe operation of the pipeline.

5. Longhorn Incorporation of Recommendations

Longhorn commits to modify the operating parameters of its pipeline segments in accordance with the third party expert findings and recommendations of the pressure-cycle-induced growth of crack analysis. Further, non-operating pressure recommendations will be submitted to the System Integrity Group for incorporation into its overall Risk Management Program.

3.5.10 Scenario Based Risk Mitigation Analysis

1. Objective

Following the relative risk assessment of the various Longhorn Pipeline segments (see Key Risk Areas Identification and Assessment Program), the Scenario Based Risk Mitigation Analysis Program is designed 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.

2. Areas of Focus

Scenario based risk mitigation assessments will typically focus on items including pipeline operations, maintenance, physical pipeline components, pipeline patrol, corrosion inspection, depth of cover, and public education. The intent is to analyze those aspects of pipeline operations and maintenance that could lead to the release of product into the environment. Consequently, the primary focus in a scenario based assessment will be on mechanical integrity, operating controls, and the prevention of third party damage.

3. **Process**

As noted above, the Scenario Based Risk Mitigation Analysis Program starts with the relative risk ranking of the Longhorn pipeline segments via the Relative Risk Assessment Model, and will be conducted annually. Next, representatives from areas including Field Operations, Pipeline Control, System Integrity, Risk Management, and Technical Services, and other subject matter experts, gather to discuss specific attributes of these risk ranked segments. Using a variety of "what if?" probing questions, the analyzed segments are thoroughly evaluated to determine the probable likelihood of an unplanned event or product release that would result in consequential damage to the environment or the population.

Following the scenario based analysis, ideas are shared on potential mitigation methods that would result in either lowering the likelihood or the consequence, or both, of an event.

The results of the Scenario Based Risk Mitigation Analysis Program are then presented back to the appropriate workgroups for consideration. As an example, items that will require the unbudgeted release of capital or expense funds are provided to the System Integrity Group for further evaluation and consideration. Items that require adjustments in operating procedures or methodologies are typically sent to the Field or Pipeline Operations Groups. In all cases, the System Integrity Group acts as the custodian for the results of this process. The System Integrity Group also scorecards these mitigation methods and provides periodic updates to Longhorn management.

3.5.11 Incorrect Operations Mitigation

1. **Objective**

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 Longhorn Pipeline.

2. **Underlying Premise**

Incorrect Operations Mitigation primarily focuses on damage prevention items and actions that are impacted by either action or inaction on the part of the operations, technical, maintenance, design, and construction personnel.

3. **Areas of Focus**

The Incorrect Operations Mitigation will focus on the following areas of potential human error that could lead to a breach of mechanical integrity:

- Design
- Construction
- Maintenance
- Operation

4. Design Index

Longhorn will incorporate Design Index attributes into new construction, system modifications, or substantive changes in Longhorn facilities. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Design Index attributes are used to mitigate potential errors by focusing on proactive error prevention actions including following:

- Hazard Identification - Incorporation of "Haz-Op," process safety management (PSM) or similar analysis on a five-year cycle, or more frequently when triggered by the Management of Change program.
- MOP Potential - Optimally strive to categorize the potential for overpressure as "extremely unlikely" or "impossible" through redundancy and critical path separation protective devices and/or processes.
- Safety Systems - Focus on the incorporation of "fail-safe" equipment and processes that reduce the likelihood of operator errors.
- Material Selection - Utilization of confirming documentation, with technical calculations, along with metallurgical review, to ensure installed equipment and components are suitable and compatible with operating and design conditions.
- Checks - Review and certification of critical design calculations and decisions, typically through a licensed engineer.

5. Construction Index

Longhorn will incorporate Construction Index attributes into new construction and system modifications. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Construction Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including following:

Inspection - Utilization of qualified inspectors.

Materials - Confirmation that installed equipment and materials are verified for authenticity and conformance to specifications.

Joining - Utilization of workmanship inspection methods, such as 100% x-ray weld inspection.

Backfill - Employ high quality of suitable backfill materials and inspection processes to ensure that no coating or pipe damage occurs, and that unintended stress forces are not inflicted upon the pipeline or accompanying components.

Handling - Ensure proper material handling practices to minimize stresses outside of component design levels and to otherwise protect the materials from damage during transporting, moving, installing, or storage.

Coating - Ensure initial and installed integrity of protective coating materials in accordance with design standards.

6. **Maintenance Index**

Longhorn will incorporate Maintenance Index attributes into the ongoing maintenance of its pipeline assets. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Maintenance Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including the following:

- Documentation - Implementation of a formal records program to ensure that defined maintenance activities are satisfactorily conducted at established intervals.
- Schedule - Development of a formal schedule of maintenance activities, with process for incorporating adjustments as a result of operating history.
- Procedures – Establishment of written procedures to guide personnel in the repair, maintenance, and replacement of equipment. Procedures will ensure that original design factors are preserved throughout the life of the equipment, or until proper validation and authorization of new factors are confirmed.

Many of the individual LPSIP programs are designed to provide a formal maintenance program which covers targeted initiatives intended to confirm, protect, or maintain the mechanical condition of the pipeline assets. Included in this category are investigative programs such as depth of cover profiling, internal "smart pig" inspections, corrosion monitoring, right of way maintenance, and external hydrocarbon monitoring programs.

7. **Operations Index**

In accordance with Muhlbauer's "Pipeline Risk Management Manual," this category of Operations Index likely represents the most critical index in terms of incorrect operations. Once the pipeline assets have been appropriately designed and installed, and are subsequently maintained in accordance with formalized schedules and programs, ongoing operations and the associated processes and procedures are the most susceptible to human error. Unlike design issues that occur in a controlled environment with typically multiple levels of checks and validations, operating decisions and actions are made over the life of the assets under a variety of circumstances. Operating decisions cover the span of normal, abnormal, startup, shutdown, and emergency conditions that by nature lend themselves to higher frequencies of errors or deviations from standard procedures.

In addition to a focus on error prevention, the Operations Index also includes a focus on the ability to detect and subsequently mitigate deviations from normal operations that could lead or contribute to a breach in mechanical integrity. The concepts of operational observability and controllability go hand in hand, and both are emphasized in Operations Index.

Longhorn will incorporate Operations Index attributes into the ongoing operations of its pipeline assets. In accordance with the "Pipeline Risk Management Manual," W. Kent Muhlbauer, Operations Index attributes are used to mitigate potential errors by focusing on proactive error-prevention actions including the following:

- Procedures - Incorporates written procedures for all aspects of pipeline operations, including startup, normal, abnormal, emergency, and shutdown situations. Particular emphasis will be given to the establishment of operating procedures for valve maintenance, safety device inspection and calibration, pipeline shutdown and startup, pump operations, product movement changes, right-of-way maintenance, flow meter calibrations, instrument maintenance, and management of change.
- SCADA/Communications - Provides an overall operational view of the entire pipeline system from a single location. The SCADA system enables system diagnosis, leak detection, and product movement analysis. The SCADA system is designed to provide continuous monitoring of the pipeline system, which allows for the incorporation of automatic alarms that detect and warn the Operations Controller of abnormal or rapidly changing conditions, and further, to provide early indication of a potentially negative event or developing situation.

  Longhorn will employ a SCADA/Communications system, which will be designed primarily to provide system overview, start/stop operations, and system isolation. The local control systems and mechanical devices located along the pipeline system will be designed to prevent overpressurization and loss of mechanical integrity. This approach places the SCADA/Communications system in a role of operations monitoring and first responder isolation versus a primary role of integrity protection.

  Longhorn will ensure that a backup communication system is employed in the event of loss of SCADA communications, although by design, such loss will not jeopardize the mechanical integrity of the pipeline system.

- Drug Testing - Longhorn will enforce the following drug testing practices for its DOT covered employees and contractors: random testing, testing for cause, pre-employment testing, post-accident testing, and return-to-work testing.
- Safety Programs - Longhorn will incorporate an encompassing Safety Managing System for its pipeline operations, with a focus on employee participation and proactive attention to safe work practices.
- Surveys - These issues are further described in other programs and initiatives, and they include surveys such as close interval, coating condition, water crossing, deformation detection by pigging, population density, depth of cover, and leak detection. These surveys fall into the proactive mode of the detection of contributing causes to the loss of mechanical integrity and incident mitigation.
- Mechanical Error Prevention - The application of mechanical devices to reduce or prevent the likelihood of operational error. These devices include the use of devices such as chains and locks, error prevention computer permissives and logic, warning signs, high profile painting of critical components, and key lock sequence programs. Longhorn shall incorporate mechanical error prevention devices where applicable to minimize the likelihood of operator error.
- Training - Viewed as the first line of defense against human error and accident reduction. Longhorn commits to approach training from a failure prevention perspective. This approach concentrates on the avoidance of any human error that

could threaten life, property, or the environment through an unintended product release.

Longhorn commits to the development and incorporation of a training program that contains the following components: product characteristic awareness, pipeline material stresses and associated component mechanical design limitations, pipeline corrosion awareness, pipeline control devices and operating knowledge, and maintenance awareness.

Longhorn further commits to the incorporation of emergency mock drills and tabletop reviews. In addition to post accident consequence mitigation, these programs will also provide operating and system integrity personnel with a proactive opportunity to identify potential contributing causes to product releases which could be prevented through the implementation of risk reduction initiatives, procedures, or processes.

- Job Skills - Longhorn commits to establishing a job skills progression program for its field operations personnel that targets a technical progression ladder. The job skills program emphasizes the following: What skills are included, the correct method of how to perform the skills, why these skills are performed and why the taught practices are the right way, and when the skills should be performed. The job skills program is designed to provide the targeted field operations personnel with the knowledge, skills, and diagnostic abilities with which to both improve efficiencies and to ensure the overall safeguarding and protection of the Longhorn Pipeline System.
- Scheduled Retraining - Longhorn commits to periodic retraining, complete with associated documentation, to ensure that trained employees retain the knowledge and proficiency with which to safely perform their required job duties.
- Operator Qualification - Longhorn will proactively comply with the proposed OPS regulation for operator qualification, verification, and certification of employees and contractors for DOT Part 195 covered activities.

3.5.12 System Integrity Plan Scorecarding and Performance Metrics Plan

1. Introduction

The intent of this section is to outline the Longhorn Pipeline System Integrity Plan Scorecarding and Performance Metrics Plan.

Scorecarding and performance metrics provide feedback to evaluate the effectiveness of the LPSIP. Through performance modeling, these measures will be used to evaluate and modify the LPSIP, using a continual improvement approach that incorporates lessons learned and trend analysis forecasting data. Empirical analysis of performance metrics will allow Longhorn to identify which activities and initiatives should be continued, enhanced, modified, or discontinued.

2. Performance Measurement

Table 1 below lists the general performance measures that will be used to evaluate the System Integrity Program.

Table 1 - General Program Performance Measurement Criteria

Category	**Measure**	**Comments**
Incident Data	Releases in each Tier	Tier I, Tier II, and Tier III
	Releases in sensitive and hypersensitive areas	Tier II and Tier III
	Releases by cause	Third party damage, corrosion, design, incorrect operations
	Releases by volume	Tier I, Tier II, and Tier III
	Near Misses	Tier I, Tier II, and Tier III
Risk Awareness	Identification of new and/or previously unrecognized risks	Scenario based analysis and individual program Recommendations.
	Number and type of projects completed that are not required by prescriptive code	Indication of proactive application of Longhorn Pipeline's System Integrity Program
Public Customer Service	Number of validated complaints on safety or environmental issues	Outward measure through public response and regulatory agencies of LPSIP effectiveness
	Number of landowner contacts related to pipeline safety and land use	Measure of Damage Prevention, dig Safely, and Third Party effectiveness Programs.
Operator Resources and Innovation	Number of new technologies, alternative methodologies and innovative approaches to control risk	Through partnering with the OPS, Longhorn demonstrates the proactive application of new ideas and technologies into the LPSIP and the Operation Reliability Assessment (ORA) Plans.

The following are measures of specific components of the System Integrity Program.

Table 2- Specific Programs Performance Measures

Program	**Measure**
Corrosion Management Plan	Smart Pig Results
Depth of Cover Program	Number, type, and location of third party damage incidents
Damage Prevention Program	Number of third party damage incidents due to One-call Process not being practiced

Additional performance measures will be developed as needed to adequately measure the effectiveness of the program.

3. System Integrity Plan Audit

As a continuous improvement process, system integrity requires program evaluation to determine effectiveness, gauge performance, and make modifications to improve the program.

Performance measures provide the means to measure progress toward established goals. Progress toward these goals will be reviewed annually through an internal audit commissioned by Longhorn.

Longhorn will review the LPSIP to re-examine the processes used to identify and assess risks, evaluate risk control options, review justification for resource allocation, and monitor performance. Performance measures will be compared against historical data and the expected outcomes. In addition, the annual review will test the quality and effectiveness of the administration, communication, and documentation of the program. The annual review report will specifically address the following five areas:

- A synopsis of the most important integrity issues being addressed on the Longhorn Pipeline System and the status of activities and programs used to manage these risks.
- Important insights, results, and lessons learned from the previous year.
- Insights from new integrity management processes or technologies, or innovative applications of existing technologies.
- Performance measurement results.
- New integrity management programs or activities that will be conducted, or significant improvements to existing programs and activities.

The LPSIP Audit Report will be provided to the Longhorn Board of Directors on an annual basis.

4. OUTLINE OF OPERATIONAL RELIABILITY ASSESSMENT FOR THE LONGHORN PIPELINE

The following discussion focuses on specific attributes of the ORA, which is intended to provide Longhorn with a technical evaluation of the integrity of its pipeline assets, and to provide specific recommendations that are intended to either preserve the long term integrity or to mitigate areas of potential concern before they can result in a breach or loss of product containment capabilities.

The overall ORA philosophy, and the included components and attributes of the data assessment process, are more fully defined in Section 3.3, "Longhorn Operational Reliability Assessment." Examples of these items include earth movement studies, third party damages, and overall LPSIP programs and data attributes.

4.1. Overview

The integrity of the Longhorn Pipeline will be monitored and any required remedial responses will be made in a timely manner to prevent leaks and ruptures. Typically, the plan and schedule by which this is accomplished is called an operational reliability assessment. An operational reliability assessment entails the use of either periodic hydrostatic testing or periodic inspections using sophisticated in-line tools or both to interrogate the pipeline. The intent is to determine whether or not injurious defects are present, and if so, to locate and repair or remove them. In the case of hydrostatic testing, the pipeline is taken out of service, filled with water, and pressurized to a level of 1.25 times the maximum operating pressure. The test either causes injurious defects to fail or proves that none exists. In the case of in-line inspection, a sophisticated tool is propelled through the pipeline with the normally transported liquid petroleum product. Depending on the design of the tool, the pipeline is inspected for cracks or corrosion-caused metal loss. The tools are capable of locating and characterizing the defects which could conceivably cause failure and smaller defects as well so that such defects can be repaired and the pipeline can be operated safely until the next inspection. The ORA takes into account the mechanisms by which defects may grow with time and the rates of growth so that a safe interval for retesting and reinspection can be established. The hydrostatic test and in-line inspection conducted in 1995 on the Longhorn Pipeline has established that no injurious defects were present at that time. The hydrostatic test and proof test being performed in 2000 will again establish confidence in the integrity of the pipeline. Future testing and inspection will be based on the analyses described below.

One type of defect that may exist in a pipeline and is known to be injurious from the standpoint of having caused leaks or ruptures in the past is the longitudinally-oriented crack. In the type of pipe of which the existing parts of the Longhorn Pipeline System (the former Exxon pipeline) is comprised, one can expect occasional longitudinal seam-related imperfections. While none of these which might still exist after the 1995 and 2000 hydrostatic tests would be large enough to cause a service failure at this time, it is possible for one or more of them to grow under the influence of fatigue from operational pressure cycles. The ORA plan calls for continually monitoring and periodically counting and assessing the service pressure cycles at each pump station. The service pressure cycles are then applied through a fatigue-crack growth model to a hypothetical family of defects which could possibly have survived the 1995 and 2000 hydrostatic tests (using typical pipeline crack growth rate historical data) causing the hypothetical cracks to grow. The number of cycles required to grow the most severe crack to failure is calculated. The period of time that it takes to accumulate that number of cycles is the minimum expected time to failure. Retesting or reinspection is then scheduled to take place by the time 45% of that time interval has expired.

The fatigue-crack growth approach can be used to establish either the interval for hydrostatic testing or for in-line inspection using a crack-detection tool or both.

The other time-dependent mechanism that might possibly be expected to affect the Longhorn Pipeline System is external corrosion-caused metal loss. Two types of in-line tools (high resolution magnetic flux leakage and high resolution ultrasonic) will be used as often as needed to assess whether or not metal loss is occurring and, if so, to determine the rate at which it is occurring. In this manner it is possible to intervene in a timely manner to repair or replace corrosion-damaged pipe before a leak or a rupture can develop. As part of the ORA, the in-line inspection data will be assessed to locate and characterize possible corrosion anomalies. The anomalies will be ranked in the order of severity and those that require repair will be addressed. The data from each new tool run will be compared to those of the previous run to establish corrosion rates. Reinspection intervals will be based on both the remaining sizes of anomalies and the rates of growth. An appropriate factor of safety based upon confidence established by direct inspection of certain anomalies will be used to set reinspection intervals so that no failure occurs between inspections. Data developed from the LPSIP Corrosion Management Plan process element (internal coupon surveys) will be incorporated into the ORA integrity analyses and recommendations (See Section 3.5.1.11 of this Mitigation Plan).

Data developed in connection with the LPSIP Annual Third Party Damage Prevention Program Assessment will be incorporated into the ORA integrity analyses and recommendations. (See Section 3.2.2.5 of this Mitigation Plan.) Finally, the regulatory concept of "High Consequence Areas" will be incorporated into the ORA integrity analyses when final rulemakings are published by DOT/OPS.

4.2. Addressing the Issue of Pressure-Cycle-Induced Crack Growth

The history of the existing 18-inch pipeline that was formerly operated by Exxon reveals that 7 service failures were associated with defects in or near the bondlines of the electric-resistance-welded (ERW) or electric flash-welded (EFW) seams. While detailed investigations were not available for review in all 7 cases, it is clear from the few that were reviewed, that at least some of these failures arose because flaws in or near the ERW seams had become enlarged by fatigue from pressure cycles. One can expect that the potential for problems from additional defects of this type exists, but as has been the case in other similar vintage pipelines, failures of this type can be prevented by appropriate and timely intervention.

One proven technology for preventing failures that may arise from pressure-cycle-induced crack growth is the use of periodic hydrostatic testing to pressure levels of 1.25 times the maximum operating pressure. In this manner defects which might eventually grow large enough to fail in service are removed if large enough to fail at the test pressure. To deal with defects that are too small to fail at the test pressure, subsequent hydrostatic tests are conducted at time intervals sufficiently small to cause any growing crack to fail during the test before it becomes large enough to fail in service.

The keys to the successful use of hydrostatic testing in this respect are:

1. Characterizing the types and sizes of longitudinally-oriented defects that could possibly exist after the most recent hydrostatic pressure test.

2. Characterizing the sizes of the same types of flaws that would cause failures at the maximum operating pressure.

3. Determining the per-cycle rate of crack growth as a function of current crack size and the range of pressure cycle.

4. Calculating the cumulative growth of the representative defects after a given time period of operation characterized by a specific pressure-cycle spectrum.

It is important to note that a reliable crack detection tool (in-line inspection tool) can be substituted for a hydrostatic test. Potentially, a crack detection tool can be better than a hydrostatic test. The traverse-field magnetic flux-leakage tool will provide a reliable substitute for hydrostatic testing as demonstrated by the following examples. Even though the TFI tool is relatively new and the technology is still evolving, several prior uses of the tool (Platte Pipe Line, for example and the Neuba II Pipeline in Argentina) have shown that the tool locates significant longitudinal defects. In one case (Platte) a hydrostatic test was performed after numerous anomalies found by the TFI tool had been removed. There were no failures during the test. In any given application of the tool, the user typically excavates and examines anomalies that the tool has located and sized. The appropriate level of confidence in the tool is derived from what the user finds upon excavation. Invariably, the tool finds anomalies that would be too small to fail in a hydrostatic test. This results in the possibility of longer intervals between inspections than between hydrostatic tests.

An Electro-Discharge Machine notch can be installed into the pipeline at the minimum detectable crack dimensions for use as a comparison. Dents and light corrosion will be analyzed by the TFI tool for cracks and additional anomalies. The effect of background noise on the detection capabilities should be available from the tool vendor. Subsequent testing on a number of anomalies (including dents and mechanical damage) with the TFI tool should better characterize the tool's detection capabilities.

A number of methods are available to utilize the in-line inspection data that are presently planned to distinguish corrosion anomalies from geometrical anomalies. Geometrical anomalies (dents and mechanical damage, primarily) provide a different signal response than corrosion on the MFL and the Ultrasonic tools. The signal characteristics of the TFI tool are still being characterized, but show significant promise in this area. The use of multiple tool technology will be used to distinguish and characterize anomalies. As additional techniques and technologies become available to distinguish corrosion from geometrical anomalies, they will be utilized for this pipeline. The MFL and ultrasonic tools have the capability to identify internal corrosion and can distinguish between internal and external corrosion.

MFL tools used to detect metal loss are generally quite accurate; typically being able to assess metal loss depth within ± 15% of the wall thickness with 95% confidence. The accuracy rating for a particular run is established or proven by "verification digs." As outlined in Section 4.3.3 of this Mitigation Plan, the probability-of-exceedance (POE) method is used to calculate the probability for every anomaly that its tool-predicted dimensions are actually larger than predicted dimensions by an amount sufficient to cause a failure at the maximum operating pressure of the pipeline. The analysis, described in Section 4.3.3 of this Mitigation Plan, further uses actually-observed corrosion rates to predict when each anomaly would be expected to reach a failure-producing size. Response plans are formulated to investigate all anomalies well in advance of their predicted times to failure. A similar strategy is used to respond to crack-like anomalies located by the TFI tool. In this case the "time-to-failure" is calculated via a pressure-cycle-induced fatigue crack growth model as described beginning in Section 4.2.2 of this Mitigation Plan. In summary, unrepaired anomalies of any kind, metal loss or cracks, are monitored as accurately as possible, and intervention to repair or reinspect them is scheduled on the basis of rational engineering formulas. See Section 3.5.2 of this Mitigation Plan at "Documentation".

4.2.1 Overview Failure Pressure Versus Defect Size

The failure pressure-versus-defect size relationships for four different types of defects that might affect the 18-inch OD by 0.281-inch w.t. 45,000-psi yield strength ERW pipe in the Longhorn Pipeline are shown in Figures 1 through 4. Each curve represents the failure pressure for a defect of any given axial length with the indicated maximum depth-to-thickness (d/t) ratio. The defect shape is assumed to be that of a semi-ellipse with its major axis equal to the maximum length of the defect at the pipe surface and its minor 1/2 axis being the maximum depth at the defect. Similar curves will be generated for all materials in the pipeline. These relationships are based upon the widely-used model for longitudinally-oriented defect behavior in pressurized pipe known as the log-secant equation (Reference 1). The only difference between the four relationships is the assumed level of material toughness as represented by a parameter called "upper-shelf energy" as determined by means of the Charpy V-notch (CVN) impact test. The higher the energy, the tougher the material, and the larger the defects it can tolerate.

On each figure two horizontal lines are drawn, one at 1250 psig representing a typical hydrostatic test pressure level for this pipe geometry and grade and one at 1000 psig representing the maximum steady-state operating pressure allowed by federal regulations for a hydrostatic test level of 1250 psig. (The regulations permit the lesser of 80 percent of the test pressure or 72 percent of the specified minimum yield strength (SMYS) of the pipe. The 1000 psig level corresponds to 71 percent of SMYS). These two horizontal lines intersect the families of d/t curves at particular length values. Each intersection represents a size of defect which can fail at that pressure level. For example, on Figure 1 (which represents the least tough material with an upper shelf energy, CVN, of only 2 ft.-lb.) the 1000-psig operating pressure level intersects the d/t = 0.9 curve at a length of about 1-inch. This means that an elliptically-shaped flaw that has a maximum length of 1-inch and a maximum depth that is 90 percent through the wall thickness would be expected to fail at the 1000-psig level. Similarly, the 1000-psig level intersects the d/t = 0.4 curve at a length of about 4 inches, meaning that a 4-inch long, 40 percent through-the-wall defect in this material will fail at the 1000-psig level.

By examining Figure 3 representing a much tougher material (CVN of 25 ft.-lb.), one can see that the defect sizes which will fail at the 1000-psig level are much larger. For example, the defect that is 90 percent through-the-wall (d/t = 0.9) must be about 1-1/2 inches long to fail at 1000 psig. Similarly, the defect that is 40 percent through-the-wall (d/t = 0.4) must be about 15 inches long to fail at the 1000-psig level.

It is noted that a leak/rupture dividing line appears on each figure. Shorter, deeper defects tend to fail as leaks; larger, shallower defects tend to fail as ruptures. The location of the dividing line is predicted by means of the log-secant equation (Reference 1).

Failure pressure-versus-defect size relationships are used in the ORA to establish defect sizes for fatigue crack growth analysis and to establish threshold detection sizes for in-line inspection. They are also used, although usually not exactly in this format, to assess corrosion-caused metal loss anomalies detected by means of in-line inspection. The four figures (Figures 1 through 4) represent the expected behaviors for four different types of longitudinally-oriented flaws. Figure 1 represents the expected behavior for ERW bondline defects such as cold welds (lack of fusion). The bondline region is usually a region of low toughness (CVN = 2 ft.-lb. assumed) so it cannot tolerate large defects. It turns out that these defects are not a significant concern from the standpoint of pressure-cycle-induced fatigue because they tend to be too small, they are below the threshold size needed to cause crack growth. This is borne out by the fact that, to our knowledge, no such defect has ever been observed to cause a fatigue-related failure in a pipeline. The 1995 hydrostatic test caused one bondline related failure (a penetrator, which is like a cold weld). While other defects of this type might still exist because they were too small to fail during the test, none will ever become a threat to serviceability of the pipeline.

Figure 2 could be taken to represent a groove-like selective corrosion anomaly centered on the ERW bondline. The average bondline properties are probably better than that associated with one containing cold weld defects so the toughness based on CVN is assumed to be 5 ft.-lb. It is expected that the transverse field, magnetic-flux-leakage tool will find these types of defects if they exist, so in the ORA we will focus on sizes that can be detected and effective growth rates that would indicate the appropriate reinspection interval.

Figure 3 will be taken as being representative of "hook cracks" which are manufacturing defects near but not in the bondlines of ERW and EFW seams. These defects have caused service failures in several pipelines including the former Exxon pipeline which is to become part of the Longhorn Pipeline. Experience has shown that these are the type of crack most often associated with failure from becoming enlarged by pressure-cycle-induced fatigue. Typically, hook cracks are initially less than half the wall thickness in depth and have appreciable lengths (3 to 6 inches or more). Even though such cracks are located near the bondline, the relevant toughness level which controls their failure behavior is more nearly that of the parent metal than that of the bondline. For this reason we have created Figure 3 based upon 25 ft.-lb. energy. The greater the toughness, the larger the defect which can survive a given level of hydrostatic test pressure. Larger defects are more likely than smaller defects to become enlarged by pressure-cycle-induced fatigue.

Figure 4 could be taken to represent the behavior of corrosion-caused metal loss anomalies. Because corrosion creates blunt, 3-dimensional flaws rather than narrow crack-like flaws, the toughness of the material is usually irrelevant. Failure of a corrosion anomaly is generally dependent only on the tensile yield and ultimate strengths of the material, and that is the basis for Figure 4. By basing Figure 4 on CVN = 500 ft.-lb., we are, in effect, saying that the material is sufficiently tough that failure is based only on tensile properties. Note that in Figure 4 the d/t relationships become almost horizontal for long defects. This is because failure depends only on the tensile properties of the net remaining wall thickness. The behavior of a long flaw in such a case is just like that of an unflawed pipe with a reduced wall thickness equal to (t-d).

Calculation methods described below will be used to predict the status of anomalies discovered by in-line inspection. Each year the fatigue and probability-of-exceedance (POE) calculations will be revised based on current pressure cycle data and observed corrosion rates. If technological advances either in inspection hardware or software are achieved the newest proven technology will be applied. Likewise, if improved analysis techniques evolve, they will be used where appropriate. Literature reviews will be periodically conducted and the plan specifics will be reviewed by independent experts to ensure that the best knowledge and practices are incorporated into the analysis. ORA processes will be updated as needed.

4.2.2 The Effect of Time Dependent Growth of Defects

Part of our approach to predicting hydrostatic retest intervals (or in-line reinspection intervals for cracks) can be explained on the basis of Figure 3. Figure 3 shows a series of arrows labeled a through g extending from the hydrostatic test pressure level to the maximum operating pressure level. Each arrow represents the growing of a defect that just survives the test to a size which will fail at the maximum operating pressure. Notice that only growth in the through-wall-thickness is represented. Experience has shown that by far, most fatigue crack growth occurs in the through-wall direction. What little does occur in the lengthwise direction can be safely ignored for analysis purposes. The physical reality that most growth is through the wall is a consequence of the stress intensity along the edge of a slowly-advancing crack. Longitudinal cracks in pipeline, if they are significant, are inherently many times longer than their through-thickness depth. Even if the stress intensity along the edge of the crack were uniform (leading to the expectation of uniform crack advance along the crack front per cycle of stress), the depth increase per cycle as a percent of crack depth would always be much higher in the through-thickness direction than the length increase as a percent of length. On top of this fact, it has been shown by fracture mechanics analysis (Reference 2) that the stress intensity factor along the crack front is much higher at the maximum depth than it is at the ends of a long crack. For this valid technical reason, one can focus on through-thickness growth while ignoring growth in length with very little loss of accuracy.

In a pipeline fatigue analysis to determine a retest interval, one examines the pressure-cycle responses of a representative number of defects of different length-depth combinations each one having an initial size that would barely survive the test (or which would be small enough to barely escape detection by means of an in-line tool). The typical approach would be to consider the defects represented by Points a through g in Figure 3. Point a represents a 1-inch long, 90-percent-through defect that just barely survives the 1250-psig test. The arrow indicates that if it grows to a depth on the order of 95 percent through the wall, it will fail at the maximum operating pressure. Similarly, Point b represents a 1.8-inch-long, 80-percent-through defect that just barely survives the 1250-psig test. The arrow indicates that if it grows to a depth on the order of 89 percent through the wall, it will fail at the maximum operating pressure. Generally, the deeper flaws will be the first to fail. This is rather clear in Figure 3 in the sense that the longer flaws cross successively more of the d/t curves. In our fatigue analysis we will calculate times to failure for Defects a through g in order to recommend the appropriate retest interval.

Figures 2 and 4, in principal, can be used to assess the time intervals between in-line inspections for metal loss. In reality, the time intervals will be based on comparisons of successive in-line inspection records because corrosion rates can be highly variable, and the actual comparisons of corrosion over time are the most accurate way to characterize the real rates. As an example, however, one can see how this might work by using Figures 2 or 4. (Figure 2 for selective seam corrosion, Figure 4 for corrosion in the body of the pipe). For example, assume that the pipe corrodes at a rate of 0.007-inch per year. Again we will also assume that the metal loss is only in the through-thickness direction. In the actual comparisons of successive in-line inspection logs, this simplification is unnecessary. The anomaly at Point a fails when the depth reaches 95 percent of the wall thickness. The amount of thickness penetrated is 0.05 percent of 0.281-inch or 0.014-inch. At 0.007 inch per year, this pit would only survive about 2 years after a hydrostatic test. Fortunately, in-line tools for metal loss detection are much more sensitive than a hydrostatic test. The 1 -inch long pit depicted in Figure 4 at Point a would probably be discovered even if it were only 20 percent through the thickness during an in-line inspection. To fail, the pit would then have to grow through 75 percent of the wall thickness or 0.211 inch. At a rate of 0.007 inch per year, this would take 30 years.

4.2.3 Crack Growth Rates

For our fatigue analysis we will utilize historical crack growth rates for typical ERW pipelines. These rates have been determined by careful analyses of actual fatigue failures. We have not been able to obtain such a crack growth rate specifically for the former Exxon pipeline, but we can examine two or three typical rates, and use the most conservative results to predict retest or reinspection intervals.

The meaning of crack growth from a fatigue standpoint is illustrated in Figure 5. This concept evolved from linear elastic fracture mechanics principles. (Reference 3) Figure 5 is a schematic representation in a log-log format of the experimentally-verified relationship between the rate of crack growth per cycle and the range of stress intensity factor (ΔK), during a given cycle at the crack front of a fatigue crack of depth "a". Large stress cycles result in large ΔK values; small stress cycles result in small ΔK values. Figure 5 predicts the amount of incremental crack growth resulting from the application of a stress cycle which produces a change in stress intensity factor of ΔK where ΔK is K_{max} minus K_{min}, K_{max} is the stress intensity factor at the maximum applied stress in the cycle and K_{min} is the stress intensity factor at the minimum applied stress in the cycle. The resulting relationship between crack growth rate (da/dN) and ΔK is shown on Figure 5 as the "Paris Law" equation named after one of the authors of Reference 3. Note that C and n in the Paris Law equation are proportionality constants that are applicable to a specific material in a specific environment.

Here is how we use the Paris Law equation. The term stress intensity factor, K, refers to a fracture mechanics concept also called, on occasion, the crack driving force. K is a function of the gross stress applied to the structure or component containing a crack and a function of the crack depth as well. Actually K is proportional to the stress and to the square root of the crack depth. If the stress level is changed by an amount, ΔS, then K is changed by an amount, ΔK As noted above the log of crack growth per cycle (da/dN) is proportional to the log of ΔK. By integrating this differential equation, one can obtain the amount of crack growth over a period of time in which a large number of stress cycles has been applied. Because ΔK is a function of both ΔS and $\sqrt{a}$, the rate of crack growth increases with time even if the size of the stress cycle ΔS, remains constant. This is illustrated in Figure 6. In terms of Figure 6, we plan to use the initial depth of crack established by the hydrostatic test (or by in-line inspection), historical crack growth rates in terms of C and n values and applied pressure cycles based on the actual operation of the pipeline to get the crack to grow to a size that will fail at the maximum operating pressure. The number of cycles required for this to occur will represent a unique period of operation involving repeated applications of representative service pressure cycles. The retesting or reinspection interval will then be set at 45% of the time to failure.

Figure 6 conveys an important concept about initial defect size and fatigue crack growth. Portrayed on the figure are three initial defect sizes represented by the letters, A, B, and C. A is the smallest, B is the next smallest, C is the largest. The horizontal lines projected from the letters intersect the crack size axis at values of 0.10 inch for A, 0.12 inch for B, and 0.13 inch for C. The crack-size-versus-cycles to failure relationship represents an actual experimental relationship for a piece of 12.75-inch-OD by 0.250-inch w.t. API 5L Grade X52 ERW line pipe with an axiallyoriented defect. The pipe was subjected to uniform pressure cycles ranging from 50 psig to 1020 psig (50 percent of SMYS) with a starting flaw length of 2 inches and a depth of 0.095 inch. Some 7000 cycles were required to get the machined notch to begin to grow. Then, after about 8000 more cycles the flaw grew to failure. The sizes A, B, and C represent depths that are calculated to be sufficient to just survive failure at test pressure levels of 1300 psig, 1250 psig, and 1200 psig, respectively. The a- versus -N relationship tells us that Defect A would grow failure at the maximum cyclic pressure after 6000 cycles (8000 minus 2000), that Defect B would grow to failure after 3400 cycles (8000 minus 4600), and that Defect C would grow to failure after 2200 cycles (8000 minus 5800). Put together into table form these predicted results are:

Defect	Test Pressure Which it Barely Survives, psig	Initial Depth, inch	Remaining Life When Subjected to Identical Cycles, No. of cycles
A	1300	0.10	6000
B	1250	0.12	3400
C	1200	0.13	2200

Comparing the results for Defect A to that for Defect C, one sees that a small increase (8 percent) in test pressure (which guarantees a smaller surviving flaw) assures a remaining life nearly 3 times as long. This is a consequence of the non-linear growth of fatigue cracks; the larger they become, the faster they grow. It also shows why very small defects have never been known to cause pipeline pressure-cycle fatigue failures and why an in-line tool which finds smaller defects than a hydrostatic test will result in either greater assurance of serviceability or a much longer interval between inspections than between hydrostatic tests. If existing arc burns or other hard spots are present on the pipeline, they would not be expected to have a higher crack growth rate than an ERW weld seam anomaly. Arc burns are not an observed cause of failure of pipelines where reasonable material toughness exists as it does in the case of the Longhorn Pipeline. As a result, arc burns are too small by their nature to be a source of catastrophic failure or leaks. Hard spots are a relatively rare cause of failure. No hard spots have been identified on the Longhorn Pipeline. There is no reason to expect that any hard spots exist on the Longhorn Pipeline, and hence the ERW weld seam anomaly should be used as the basis for predicting reinspection or retesting intervals. If additional information is obtained through research and/or ORA experience, the information will be used to refine and enhance the defect model.

4.2.4 Hypothetical Example

From the standpoint of pressure-cycle-induced fatigue we cannot carry out an analysis of the effects of pressure cycles for the Longhorn Pipeline until it is in service and some amount of cyclic pressure history begins accumulate. After a few months during which time the complete pressure history is recorded, we will be able to carry out an analysis to project the status of crack growth using initial defect sizes consistent with the 1995 and 2000 hydrostatic tests. We will periodically update the analysis as more cycles accumulate. Based on these calculations we will recommend a hydrostatic retest or in-line inspection interval. The first retest will establish a new baseline set of initial crack sizes and the process can be repeated. Alternatively, we may be able to establish the transverse field inspection tool as a substitute for hydrostatic retesting.

While we cannot conduct the actual analysis until we are able to determine the sizes and numbers of pressure cycles, it is useful to consider a hypothetical case based upon an actual pressure history and crack growth rate for another pipeline. The other pipeline, which we will call Pipeline X, is similar to the Longhorn Pipeline in several important ways. It is close to the same diameter, and it contains a similar-vintage and type of ERW pipe. Also, it has experienced service failures from pressure-cycle-induced crack growth of hook cracks. After being subjected to an ORA and to two rounds of hydrostatic retests, it has been operated successfully for a period of 10 years with no failures from pressure-cycle-induced fatigue.

The typical 14-day operating pressure spectrum for the most intensely pressure-cycled portion of Pipeline X is shown in Figure 7. The maximum pressure level in this spectrum is 938 psig; the minimum pressure level is 70 psig. The crack growth rate constants for Pipeline X as determined from analysis of one of the service failures are: C = 5.56 E-18 for ΔK in $psi\sqrt{in.}$ units and n = 2.77. Using our personal computer program called PIPELIFE which sums cycles by numerically integrating the Paris Law equation, the pipe geometry and material properties for the 18-inch OD by 0.281-inch w.t., 45,000 psi Longhorn material, and nine representative initial flaw sizes established by the 1995 test of the Longhorn Pipeline, we calculated times to failure for the nine representative defects. The output from PIPELIFE is shown in Figure 8 and the results are summarized below.

Defect	**Axial Length, inches**	**Depth, a, inch**	**A/t ratio**	**Years to Failure**
1	1.08	0.253	0.9	7.8
2	1.69	0.225	0.8	8.0
3	2.35	0.197	0.7	8.6
4	3.19	0.169	0.6	9.4
5	4.49	0.141	0.5	11.2
6	6.77	0.112	0.4	17.1
7	10.51	0.084	0.3	36.6
8	15.41	0.056	0.2	96.7
9	21.06	0.028	0.1	293.1

Based on the shortest time to failure in this hypothetical case, 7.8 years, we would recommend that a hydrostatic test or TFI tool in-line inspection be conducted 3 to 4 years after the pipeline is placed in service. This example merely illustrates how we will conduct the fatigue part of the ORA. The actual pressure history of the Longhorn Pipeline and its associated crack growth rates may produce different results.

4.3. Analysis of Corrosion Anomaly Results Longhorn Pipeline Crane to Kemper and Kemper to Satsuma

4.3.1 Introduction

Presented herein are the results of our analysis based upon the in-line inspection data for the Crane to Kemper and the Kemper to Satsuma pipeline segments. An analysis was performed to determine if any corrosion caused anomalies exist on these pipeline segments that would be expected to fail in the near term due to the startup of these line segments. The analysis results are based upon the 1995 inspections. As a continuing part of the ORA, this type of analysis will also be conducted in conjunction with future in-line inspections for corrosion caused metal loss.

4.3.2 Background

In-line inspections of these segments were conducted in 1995 to evaluate the extent of corrosion-caused metal loss. The 1995 inspections were carried out by Vetco utilizing a standard resolution magnetic flux tool.

4.3.3 Approach

In-line inspection results are commonly used by pipeline operators as a means for remediating corrosion caused metal loss. This typically involves conducting an in-line inspection and excavating 'significant' corrosion features identified by the tool. Corrosion is characterized as significant based upon the maximum depth of corrosion (e.g., greater than 50% wall loss) or the safety margin (e.g., 1.39) between the predicted failure pressure[1] and the operating pressure. This deterministic method is a valid approach for addressing integrity concerns.

Statistical methods have been developed for further analysis of in-line inspection data. One of the methods is referred to as 'Probability of Exceedance' (POE) analysis. The results of a POE analysis can be used by pipeline operators as an additional tool for using in-line inspection data for managing the long term integrity of pipeline systems.

One important feature that a POE analysis can provide is to rank corrosion anomalies individually, by joint of pipe, by incremental distance, or by pipeline segment. This process highlights those pipes or areas of the pipeline with many significant anomalies. A cumulative probability can be calculated for the entire group of anomalies which can be used to compare different pipeline segments. Corrosion rates can be utilized to recalculate anomaly probabilities over time. These can be used to determine a repair strategy and a reinspection interval.

---

1 The predicted failure pressure is based upon the B31G or RESTRENG 85% Area Criterion and uses the overall length and maximum depth of corrosion provided by the tool.

Ideally, perfect agreement would exist between these tool's predicted depth and the actual depth of corrosion. Unfortunately, this is generally not the case. In-line inspection vendors typically report a depth measurement accuracy of $\pm$10% of wall thickness, 80% of the time. This translates to $\pm$15%, 95% of the time for the statistical calculations.

The POE analysis methods embodied in this report evaluate the probability that, given a pig call, the depth of corrosion is greater than 80% of the wall thickness or the predicted failure pressure is less than the maximum operating pressure of 72% SMYS. These analyses are based upon a corrosion depth confidence interval of $\pm$15%, 95% of the time.

Two probabilities are calculated for each corrosion anomaly. The first calculation is the probability that the anomaly will leak. This is based on the probability that an anomaly is deeper than 80% of the wall thickness. The second calculation is the probability that the anomaly will cause a rupture. This is based on the probability that the predicted anomaly failure pressure is less than the maximum operating pressure of the pipeline segment.

To evaluate the status of corrosion and projected changes in corrosion over time, a corrosion growth rate of 1 mil (0.001 inch) per year was used on the reported depths of corrosion. This rate was chosen to reflect a pipeline that is under good levels of cathodic protection. A corrosion rate of 7 mils (0.007 inches) per year was also used. This corrosion rate would be applicable to a pipeline with little or no cathodic protection and aggressive corrosion. The length of corrosion was assumed to remain constant for the purpose of this assessment. The severe anomalies were assumed to be 50% deep in 1995. The moderate anomalies were assumed to be 25% deep in 1995. The light anomalies were assumed to be 15% deep in 1995. The lengths used for calculations of the moderate and severe anomalies are those in the Vetco Report. The lengths used for calculations of the light anomalies were assumed to be 6 inches.

4.3.4 Analysis Results

POE analysis results for the Crane to Kemper segment are presented in Table 1. POE analysis results for the Kemper to Satsuma segment are presented in Table 2. The shaded odometer

$$POE_{Joint} = 1 - (1 - POE_1)(1 - POE_2)\ldots(1 - POE_i)$$

numbers in Table 1 and Table 2 are those anomalies that were addressed in 1995(i.e. they were excavated, examined, and repaired if necessary). The POE results presented in Figures 9, 10, 11, and 12 summarize these results. These results were generated as follows. A POE was calculated for each pig call. The POE for each joint of pipe was then calculated as follows:

where POE_i is the $^{(i)}$ number of pig calls on each pipe joint. The 1995 inspection only reported the worst anomaly per joint. Therefore the joint POE will be equal to the individual pig call. A POE analysis is actually better suited for high resolution inspection tools that report all anomalies on each joint. In that case, fewer assumptions are necessary for such an analysis. Nevertheless, POE analyses for the 1995 tool runs were carried out. After the POE was calculated for each pipe joint, the results were sorted from highest to lowest POE.

Figure 9 is a set of plots of the maximum and cumulative probabilities based on the tool interpretation versus the number of pipe digs, for the Crane to Kemper segment. Figure 10 is a set of plots of the maximum and cumulative probabilities based on the tool interpretation versus the number of pipe digs, for the Kemper to Satsuma segment. Figure 11 is a set of plots of the maximum probabilities for 1995 and for 1999, using the corrosion rates of 1 (mil/yr) and 7(mils/yr), versus the number of pipe digs, for the Crane to Kemper segment. Figure 12 is a set of plots of the maximum probabilities for 1995 and for 1999, using the corrosion rates of 1 (mil/yr) and 7(mils/yr), versus the number of pipe digs, for the Kemper to Satsuma segment.

4.3.5 Interpretation of Results

Several approaches can be followed to identify additional excavation locations and/or to establish a reinspection interval. This can be accomplished by either identifying a target POE level to maintain for this pipeline system and/or by identifying excavations that will be required to maintain a maximum POE level and reasonable inspection interval. The results of these assessments are provided below.

These assessments have been completed by evaluating the POE calculated for every pipe joint.

The Crane to Kemper pipeline segment contained 26 severe and moderate anomalies as reported by Vetco in 1995. A review of the repair inspection data shows that 24 of these anomalies were repaired. This included 4 severe anomalies out of 4 total and 20 moderate anomalies out of 22 total. For this assessment, a starting point of 180 pipe excavations was utilized.

The 1995 dig program reduced the maximum probability from 7.52 x 10-1 to 9.89×10^{-5}. When the remaining anomalies are reevaluated for 1999 using the corrosion growth rate of 1 mil per year, the maximum probability is now 2.51×10^{-4}. When the remaining anomalies are reevaluated for 1999 using the corrosion growth rate of 7 mil per year, the maximum probability is now 2.30×10^{-2}.

A total of 1 additional dig would be required to bring the year 1999 maximum POE to less than 9.89×10^{-5} , if we assume a corrosion rate of 1 (mil/yr). A total of 1 additional dig would be required to bring the year 1999 maximum POE to less than 9.89×10^{-5}, if we assume a corrosion rate of 7 (mil/yr). This is due to getting credit for four previous digs by digging one new dig.

The Kemper to Satsuma pipeline segment contained 393 severe and moderate anomalies as reported by Vetco in 1995. A review of the repair inspection data shows that 180 anomalies were repaired. This included 78 severe anomalies out of 78 total and 102 moderate anomalies out of 315 total. For this assessment, a starting point of 180 pipe excavations was utilized.

The 1995 dig program reduced the maximum probability from 8.77×10^{-1} to 4.24×10^{-4}. When the remaining anomalies are reevaluated for 1999 using the corrosion growth rate of 1 mil per year, the maximum probability is now 1.03×10^{-3}. When the remaining anomalies are reevaluated for 1999 using the corrosion growth rate of 7 mil per year, the maximum probability is now 6.13 x 10^{-2}.

A total of 55 additional digs would be required to bring the year 1999 maximum POE to less than 4.24 x 10^{-4}, if we assume a corrosion rate of 1 (mil/yr). A total of 223 additional digs would be required to bring the year 1999 maximum POE to less than 4.24 x 10^{-4}, if we assume a corrosion rate of 7 (mil/yr).

4.3.6 Discussion of Results

The Probability of Exceedance results presented within this report have been provided as an additional tool for the integrity of the system. The calculations suggest that the probability of a leak or a rupture at this time is no greater than 0.06. This information can be used for evaluating the options for these pipeline segments. Our recommendation is to conduct an inspection using a high resolution tool as soon as possible after the pipeline is placed in service.

The results also provide a comparison between the deterministic approach, where defects exceeding 30% of the wall thickness or having a failure pressure less than 100 percent of SMYS are excavated for examination and repair. The POE results may identify locations where the corrosion dimensions reported by the tool may have just barely passed the deterministic assessment. Therefore, this approach identifies additional locations that should be considered for excavation. Table 3 lists the corrosion depths and the rupture pressure ratios that correspond with selected probabilities.

The corrosion growth rates used within this analysis were assumed to be 1 and 7 mils per year. Obviously, these growth rates are subject to debate since no detailed assessment has been completed to establish this rate. Additionally, the corrosion growth rates can be changed for different pipeline systems depending on whether the growth rate is expected to be higher or lower than this value. Changes in the corrosion growth rate will affect the future results presented in this analysis.

One of the most important aspects of this analysis is the confidence level of ILI results used in this assessment. The POE analysis was designed to be used with high resolution tool data with an extensive number of verification digs. The POE analysis is normally based upon the correlation between the depth of corrosion measured in the field and the depth reported by the tool. Additional assumptions must be incorporated into the analysis to utilize standard resolution inspection data.

A good correlation between the length of corrosion reported by the tool and that measured in the field is often difficult to obtain. The difficulty is likely a function of how the length of corrosion is identified by the tool with respect to interaction of adjacent areas of corrosion and how the length of corrosion is defined in the field. The POE results presented in this report are based on the assumption that the length of corrosion is accurate. The validity of this assumption has a significant influence on the results.

REFERENCES

1. Kiefner, J. F., Maxey, W. A., Eiber, R. J., and Duffy, A. R., "Failure Stress Levels of Flaws in Pressurized Cylinders", Progress in Flaw Growth and Toughness Testing, ASTM ST 536, American Society for Testing and Materials, pp 461-481, 1973.

2. Raju, I. S., and Newman, J. C., Jr., "Stress-Intensity Factors for Internal and External Surface Cracks in Cylindrical Vessels", *ASME Journal of Pressure Vessel Technology,* pp 293-298, November 1982.

3. Paris, P. C., and Erdogan, F., "A Critical Analysis of Crack Propagation Laws", *Transactions of the ASME, Journal of Basic Engineering,* Series D, 85, (3), 1963.

Table 3. Probabilities and their associated depths and RPRs

Probability	Corrosion Depth	Rupture Pressure Ratio
1.0×10^{-1}	69%	0.84
1.0×10^{-2}	60%	0.90
1.0×10^{-3}	54%	0.94
1.0×10^{-4}	48%	0.98
1.0×10^{-5}	44%	1.01
1.0×10^{-6}	39%	1.04
1.0×10^{-7}	35%	1.07
1.0×10^{-8}	32%	1.09
1.0×10^{-9}	29%	1.11
1.0×10^{-10}	25%	1.13

4.4. Overpressure Protection Devices

Prior to startup, Longhorn Pipeline will complete an evaluation of all overpressure protection devices, and will implement the recommended mitigation actions resulting from the study. Specifically, the effectiveness of the overpressure devices functionality and the applicability of operating and maintenance procedures will be evaluated to ensure that the pipeline and its associated equipment can be safely operated within the operating pressure parameters established in the surge analysis and established piping pressure limitations. The technical evaluation will include an evaluation of overall system overpressure hazards and operability and human interface issues in order to remain within the established pressure limitations.

The technical evaluation of the overpressure protection devices will be commissioned by Longhorn and conducted by a reputable third party company with demonstrated engineering and system design/analysis/assessment competencies.

4.5. Non-Pipe System Components

Prior to startup of the Longhorn Pipeline System, an independent integrity evaluation will be completed for all non-pipeline system components. This study will include engineering evaluation of the existing component integrity judged against the design System operating pressures and parameters, and will additionally include plans and guidelines for the verification of future components that may be incorporated into the Longhorn Pipeline System.

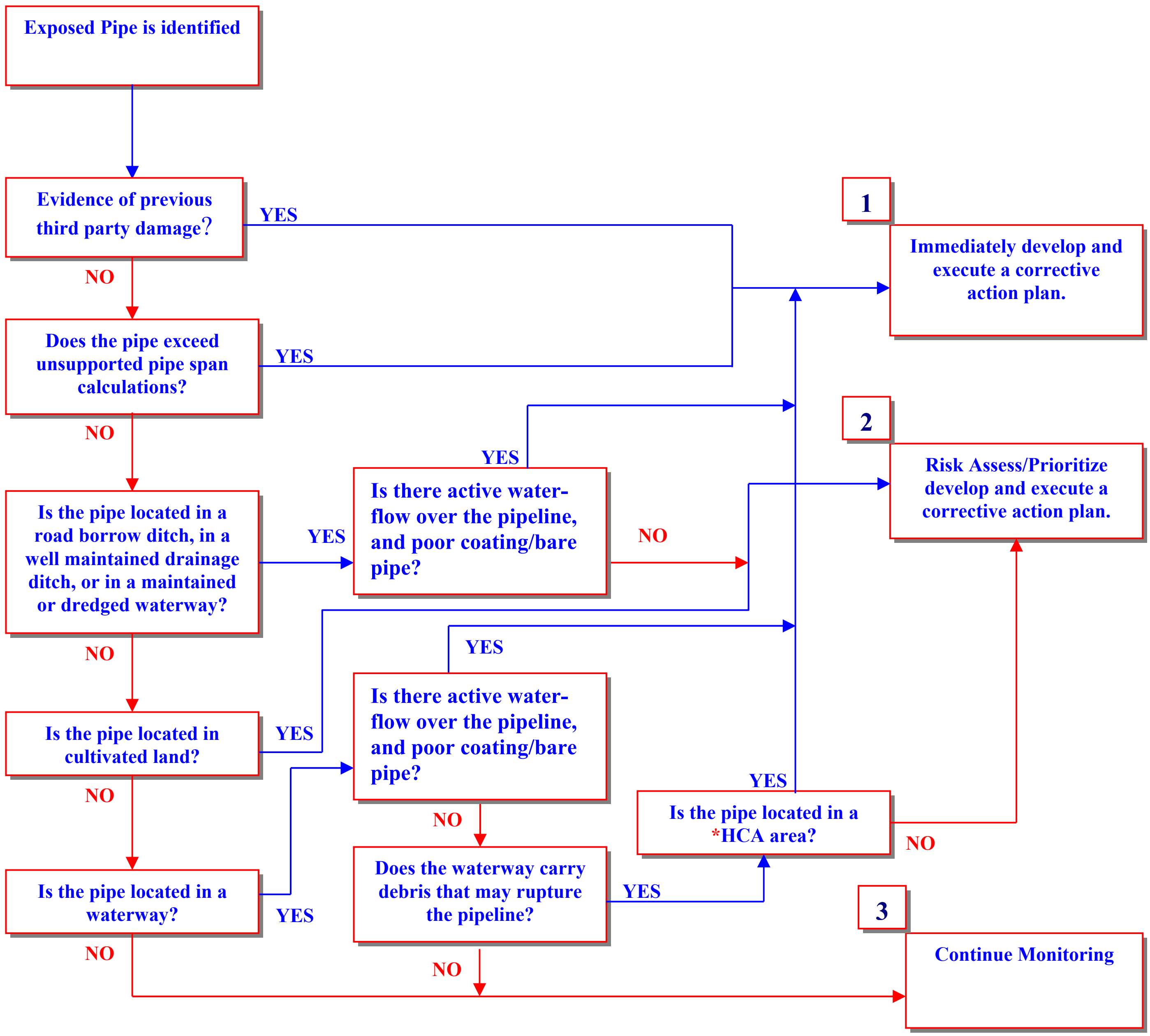
An evaluation of all hazards, operability, and human interface factors, complete with recommended and subsequently completed System Integrity deficiencies and risk mitigation action items will be completed prior to startup. A reputable third party company with demonstrated engineering and system design/analysis/assessment competencies will be commissioned by Longhorn.

5. FIGURES AND TABLES

5.1 Figures 1 and 2 for the Depth of Cover Program, Section 3.5.8.

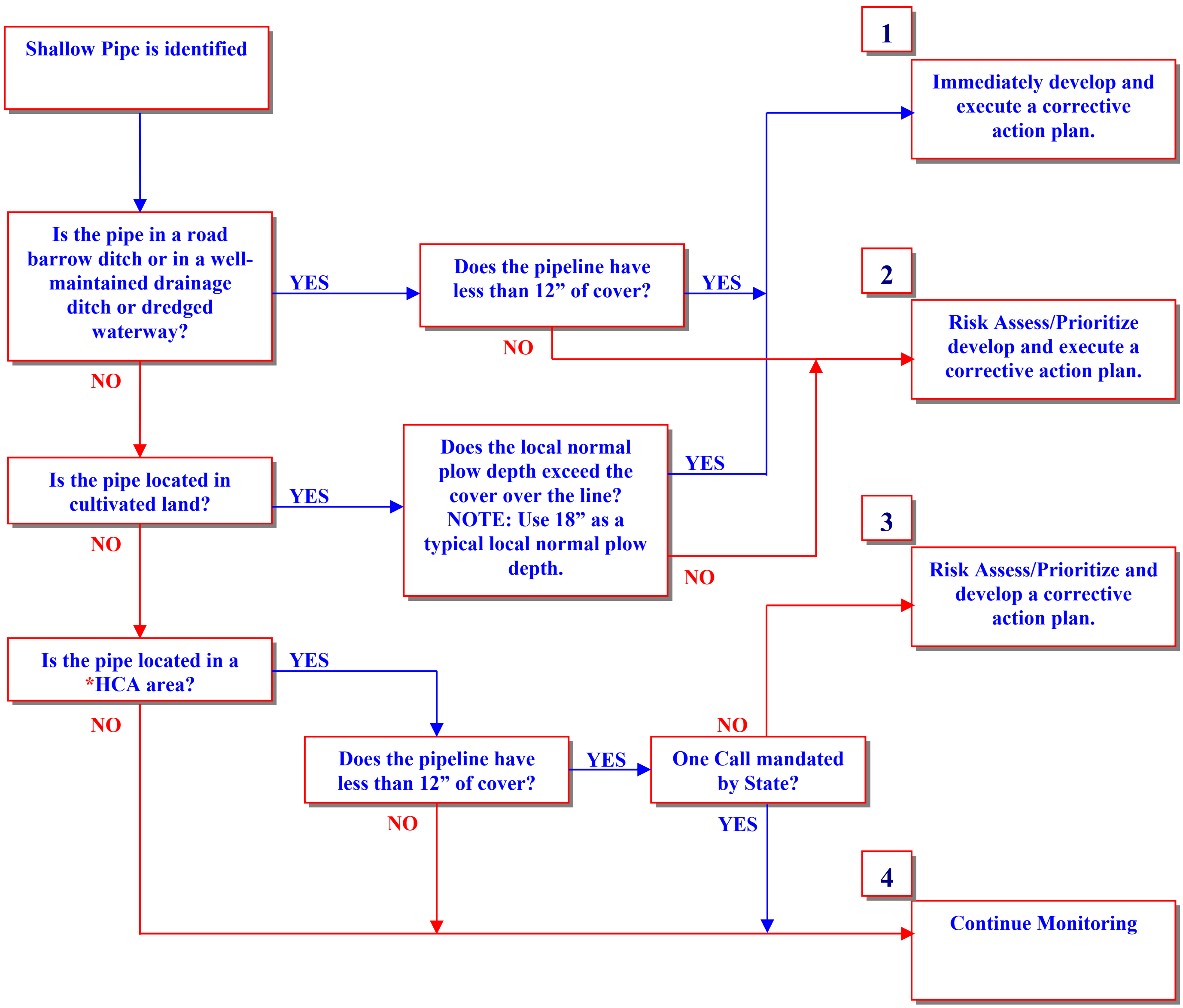
5.2 Figures 1 through 12 and Tables 1 through 3 for the Outline of the ORA, Section 4.

Prioritization for Exposed Pipe (Flow Chart



* HCA (High Consequence Area) High populated and/or High environmental impact area.

Prioritization for Shallow Pipe (Flow Chart)



* HCA (High Consequence Area) High populated and/or High environmental impact area.