Appendix 6B

Leak Detection

Leak Detection

The existing methods of detecting a leak were summarized in the EA in Section 5.2.7. Additional information is provided below and in the revised Longhorn Mitigation Plan (Appendix 9C of the final EA).

Existing System

The leak detection system used by Williams Energy Services (WES), the Longhorn's proposed operator, relies upon (1) external patrols, (2) pressure and flow measurement deviation beyond an upper or lower threshold, and (3) volume balancing to detect the possible existence of a leak. The most sensitive of these methods is volume balancing. Volume balancing is the comparison of the volume pumped to the volume received on any given line configuration. WES operates on a net metering basis, i.e., a barrel pumped into a pipeline configuration should be equivalent to a barrel received if no operational changes have been made on the line segment under consideration. Simple volume balancing can only be applied during steady state operation and for those line segments that have flow meters at both the inlet and outlet.

A manual volume balance is performed every two hours for each line segment bounded by flow meters. The tolerance for meter inaccuracies is 0.3 percent of full scale for each meter, with a maximum of 0.6 percent per configuration, based on the smaller volume of either the pump meter or the receive meter. Thus, the sensitivity in determining the volume balance is dependent on the ratio of the actual flow rate to the maximum measurable flow rate. The sensitivity of the volume balance will be less than 0.3 - 0.6 percent (i.e., the best measurable closure will be > 0.3 - 0.6 percent flow) for flow rates below the maximum measurable flow rates.

If the volume balance tolerance is exceeded, and a leak is not immediately evident or suspected, the meters are proved. If the tolerance of the meter(s) is still exceeded after proving, the line will be shut down, under pressure, for a period of not less than two hours. The purpose of the shutdown is to verify the integrity of the line.

If the meter provers are inoperable or if part of the mainline metering is not operational, tank gauging will be used to perform volume balances. In these cases, the tolerance is increased to 0.5 percent per meter and a maximum of 1 percent per configuration.

Proposed System for the Mitigated Longhorn Pipeline

UTSI International Corporation (UTSI) performed theoretical analyses of the existing Longhorn configuration and WES SCADA system to estimate the capabilities of state-of-the-art leak detection systems applied to the Longhorn pipeline. The capabilities of these systems are based on the theoretical estimates derived by using the API 1149 procedures and by UTSI's experience with similar systems. API 1149 was developed to provide techniques for quantifying the effects of variable uncertainties on the leak detection capabilities of software-based leak detection systems. These techniques can be used to determine the achievable level of leak detection for any pipeline characterized by a specific set of instrumentation and appropriate SCADA capabilities.

Two analyses of the Longhorn pipeline were performed by UTSI using the techniques provided in API 1149. It was assumed, for both analyses, that a state-of-the-art fluid transient simulation model would be used to achieve the highest degree of leak detection sensitivity.

In the first analyses, defined as the Overall Pipeline Scenario, the entire pipeline was treated as a single volume balance element, i.e., flow meters are only operational at the Galena Park Station located in Houston and El Paso locations. There were no modifications or additions to the existing pipeline instrumentation. In the standard API 1149 approach, pipeline leak detection sensitivity is limited by the uncertainty in calculating the line fill volume that is corrected for temperature and pressure variations. Pressure and temperature measurement errors have an immediate impact on this uncertainty. In applying the standard API 1149 method, uncertainties in temperature and pressure measurements were derived from the manufacturer's specifications for the instruments on the pipeline. There are several different instruments associated with the pressure and temperature measurement uncertainties required in using the API 1149 methodology. USTI assumed that the average error for each instrument was equal to one-half of the manufacturer's worst-case specification for pressure and temperature measurements. The leak detection capability was determined for quasi-steady state operating conditions at a flow rate of 3000 bph, a temperature of 80°F, and a total line fill of API 65 product.

The results of applying the standard API 1149 methodology to the Longhorn pipeline are summarized in Table 1. The application of this approach produces leak detection capabilities that are generally high, ranging from 122 to 1.36 percent of flow. Approximately 61 barrels of product would be lost before the leak was observed. The results shown in Table 1 show worst-case detection times that were developed under the assumption that the leak occurred at the midpoint of the longest pressure-bounded segment. According to UTSI, this performance estimate does not present an appropriate indication of potential leak detection performance that can be achieved with contemporary leak detection systems. The standard API 1149 methodology assumes that the performance of the leak detection system is limited by the absolute uncertainty in each instance of the line fill calculation. Most modern leak detection systems have long-term error compensation algorithms. The leak detection system calculations are based on relative changes, as opposed to absolute discrepancies, in the line fill and associated volume balance. Thus, with state-of-the-art systems, the leak detection sensitivity is not limited by the absolute uncertainty in the measurement of pressure, temperature, and flow. Instead, the leak detection sensitivity becomes a function of the relative errors between these measurements taken at different points in time.

If the API 1149 methodology is to be used to get a truer estimate of leak detection performance of state-of-the-art systems; therefore, the repeatability of successive measurements should be incorporated into the model, rather than the errors associated with single measurements of the pertinent parameters. To use the API 1149 methodology to estimate the performance of modern leak detection methods, UTSI made the following adjustments in applying instrument error specifications for pressure, temperature, and flow measurements:

Table 1. Results of the Overall Pipeline Scenario Analysis

Observation Interval, minutes	Leak Condition at Time of Observation		
	Percent of Flow, percent	Leak Flow Rate, bbl/hr	Volume Discharged, bbls
1	121.89	3657	61.0
2	60.95	1828	60.9
3	40.65	1219	61.0
5	24.38	731	60.9
10	12.19	366	61.0
20	6.1	183	61.0
30	4.07	121	60.5
60	2.04	60.1	60.1
90	1.36	40.9	61.4

- The instrumentation errors were adjusted downward in recognition that scale factor and non-linearity are less important to modern leak detection system performance than repeatability errors and histories; and

- Instrument errors were adjusted to a log-linear function of the observation interval, since the measurement errors are correlated, and this correlation is an inverse function of the time between successive measurements.

A second scenario, identified as the Three-Segment Scenario, was defined for evaluating leak detection capabilities under conditions that are more consistent with actual performance of modern leak detection systems. The adjustments listed above were incorporated in to the methodology. UTSI found that leak detection capability of the existing system could be significantly improved with the installation of some additional instrumentation, and the analysis was conducted under the assumption that this instrumentation was added to the system. These additions include a few new temperature and pressure measuring devices, a density meter at Galena Park Station, and two inline flow meters at Cedar Valley and Crane stations. This latter addition divides the pipeline into three segments for evaluation. This scenario represents a reasonable enhancement of the instrumentation that should provide a significant improvement in leak detection performance. The performance levels of this system operating at 3,000 bph, a temperature of 80°F, and a total line fill of API 65 product were determined using the “enhanced” API 1149 methodology.

These performance levels are summarized in Table 2. The highest calculated sensitivities, 0.3 – 0.4 percent of flow, are found at the 90-minute observation time, but the total volumes leaked over the period prior to the leak determination was also greatest at this time (14 – 20 barrels). These leak detection sensitivities are significantly lower than those calculated for the Overall Pipeline Scenario.

Table 2. Results of the Three-Segment Scenario Analysis

Observation Interval, minutes	Leak Condition at Time of Observation								
	Galena Park Station to Cedar Valley Station			Cedar Valley to Crane Station			Crane Station to El Paso Terminal		
	Percent of Flow, percent	Leak Flow Rate, bbl/hr	Volume Discharged, bbls	Percent of Flow, percent	Leak Flow Rate, bbl/hr	Volume Discharged, bbls	Percent of Flow, percent	Leak Flow Rate, bbl/hr	Volume Discharged, bbls
1	2.95	88.4	1.5	4.3	129.1	2.2	3.66	109.7	1.8
2	2.71	81.3	2.7	3.96	118.7	4.0	3.37	101.2	3.4
3	2.46	73.8	3.7	3.59	107.7	5.4	3.06	91.9	4.6
5	2	59.9	5.0	2.91	87.5	7.3	2.49	76.7	6.4
10	1.36	40.9	6.8	1.99	59.7	10.0	1.7	51	8.5
20	0.87	26.1	8.7	1.27	38	12.7	1.08	32.5	10.8
30	0.66	19.7	9.9	0.95	28.6	14.3	0.82	24.5	12.3
60	0.41	12.2	12.2	0.58	17.4	17.4	0.5	15	15.0
90	0.31	9.4	14.1	0.43	13	19.5	0.38	11.3	17.0

Longhorn has selected a fluid transient model-based leak detection system to monitor the operation of the Longhorn pipeline. UTSI believes that this system is quite capable of achieving the level of performance suggested in UTSI's analysis of the Three-Segment Scenario (Letter from Daniel W. Nagala. UTSI, to Robert Wetherold, Radian, Re: LPP Leak Detection Sensitivity, December 17, 1999). In addition to the instruments recommended in the Three-Segment Scenario, Longhorn is also installing flow meters at several other strategic locations to further assure achievement of the performance targets. As stated in the letter (Nagala, 1999), "UTSI is comfortable with the performance projections published in its April 9th report and believes that they will be achieved as the Longhorn leak detection system is tuned during the installation process."

This system requires a period of approximately 6 months to be properly tuned to achieve leak detection levels as low or lower than those shown in Table 2. The leak detection system is also effective in detecting leaks during transient operation.

The performance of the leak detection system can be checked periodically by inducing "leaks" (at sampling points, valves, etc.) of known rates at locations along the pipeline where the fluid in the pipeline can be released at known rates and under controlled conditions. These "leaks" are sometimes induced without alerting the system operators.

In addition to the computational-based leak detection system, TraceTek® fuel-sensing cable, a Raychem product, will be buried along the three-mile section of new pipe that will be installed across the Edwards Aquifer recharge zone. This cable senses the presence of hydrocarbons at any point along its length. When the cable senses the hydrocarbon liquid, it triggers an alarm and identifies the location of the liquid. Tests by Carnegie Mellon University have shown that, when exposed to gasoline liquid rates of 0.128 gal/hr, the response time of the cable ranged between 7.5 and 12.0 minutes (Memo from Rob Wasley, TraceTek Technical to Randy Allen, UTSI, December 6, 1999.) Thus, the cable alarmed after being exposed to 0.016 – 0.026 gal. of gasoline. Response times range from 10 minutes to 2 hours, depending on the hydrocarbon product, as shown in the table of manufacturer's specifications below.

Product	**Response Time, minutes**
Gasoline	12
No. 1 Diesel	60
No. 2 Diesel	120
JP-8 Jet Fuel	70
JP-5 Jet Fuel	50
JP-A Jet Fuel	50

This system is sensitive to very small leaks, particularly those of gasoline. The location of any leaks detected with this system can be determined within a few yards.

With notification from external patrols, the computational-based leak detection system, or the TraceTek system, Longhorn will facilitate the orderly and controlled shutdown of its system within five minutes of a probable leak indication.