Pipeline Integrity Management of Unpiggable Pipelines – A Case History

by **Arash Ilbagi, Ahmad Saab, and Frank Gareau**
Acuren Group Inc., Calgary, AB, Canada

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Abstract

Two unpiggable pipelines were installed in a common trench in 1983. One was a 4-inch high vapour pressure liquid hydrocarbon pipeline and the other was a 34-inch natural gas pipeline. Both pipelines were externally tape coated and experienced external corrosion challenges. This paper will address the integrity challenges and solutions that were implemented for these two pipelines.

Early random excavation and inspection of the 34-inch pipeline indicated that the pipeline was in relatively good condition. Over-the-pipeline surveys were then completed to identify focal points for inspection for both pipelines. A leak from the 4-inch pipeline triggered an in-line tethered inspection that was performed from the failure location. This paper will compare over-the-line survey data with in-line inspection data and direct inspection data after the pipelines were excavated. Both pipelines were observed to experience the same mode of degradation. The consequence assessment for the 34-inch pipeline was significantly different than the 4-inch liquid hydrocarbon pipeline. This paper will also discuss risk methodology differences and challenges for the two pipelines.

Introduction

Pipeline integrity management systems (IMS) are now being used by almost all pipeline companies to understand and control the likelihood and the consequence of failure. IMS has replaced the time-based inspection and maintenance plans with prioritization based on risk to people, property, or the environment should a pipeline fail. This is achieved by the IMS identifying threats to a pipeline. A classification of such threats is provided in Managing System Integrity of Gas Pipeline (ASME B31.8S). When the threats associated with the pipeline system are identified, a process that is based on the continual improvement cycle of 'Plan, Do, Check, Act' can be implemented. This process should include selection of appropriate monitoring, inspection, and mitigation techniques, implementation, review and analysis of data, selection between repair or continued service, risk assessment, and management review. All must be completed by trained and competent personnel and documented.

One category of pipelines that have challenged pipeline companies are unpiggable pipelines. Pipelines are typically identified as unpiggable due to difficulty in performing the pigging, or presence of unknowns that would render pigging too risky. Some of the perceived barriers to pigging may include physical barriers, low pressure, low flow rate, multi-diameter, and access. However, being difficult to pig shall not stop a company from performing appropriate integrity assessments. Performance of such assessments may take creativity, planning and financial commitment that is, in some cases, warranted by safety and operational risk.

The case reviewed in this article follows actions of a pipeline company as it was maturing in IMS. Unfortunately, in this case, time did not allow for prevention of the failure; however, the review of this incident highlights the importance of taking the right steps from the beginning to prevent a failure.

System Description

This case history is for two pipelines that were constructed in the same right of way. Both pipelines were constructed in 1983 to transport dehydrated natural gas (NG) and liquefied petroleum gas (LPG), i.e. propane-plus products, from a straddle plant to the customer's plant. See Table 1 for more detailed pipeline specifications. The natural gas pipeline was a steel pipeline with 34" OD and 0.38" WT and it was coated with a single wrap of 4"-wide black polyethylene (PE) tape. The specified minimum yield strength (SMYS) of the pipeline was 65,300 psi (~X65) and the maximum operating pressure (MOP) was 800 psi.

The LPG pipeline was a 4" OD, 0.13" WT steel pipeline with SMYS of 52,200 psi (~X52) and MOP of 1945 psi. It was also externally coated with similar polyethylene tape.

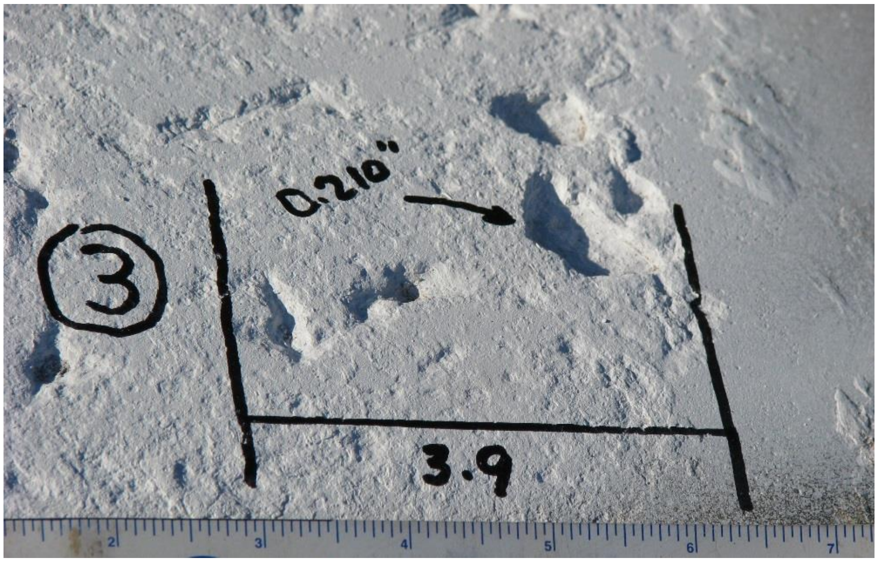
Table 1. Pipelines Specifications.

Pipeline Substance	OD (Inches)	WT (Inches)	MOP (psi)	SMYS (psi)	Piggable?
NG	34	0.38	800	65,300	No
LPG	4	0.13	1945	52,000	No

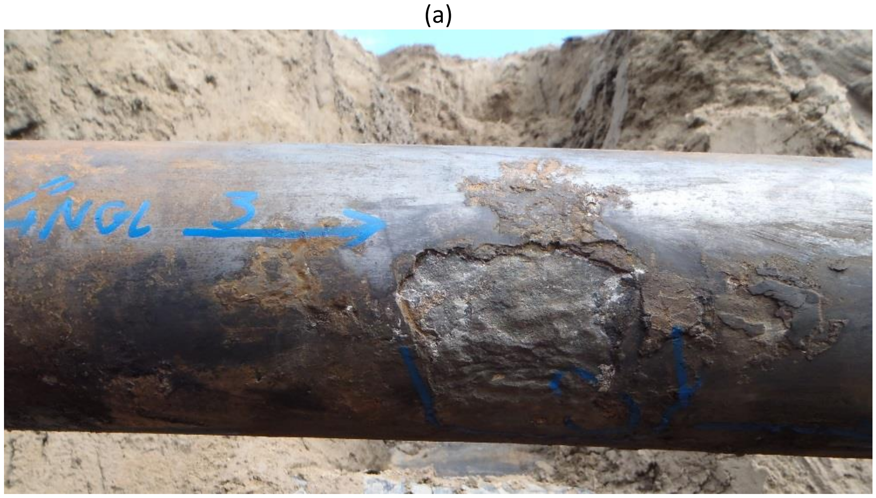
Both pipelines received cathodic protection from an impressed current system located at both ends of the pipelines. Annual cathodic protection surveys showed that the structure to electrolyte potentials surveyed met the -850 mV polarized instant-off potential criterion at test stations.

Previous Inspections

As per ASME B31.8S, Managing System Integrity of Gas Pipelines, the first step in managing pipeline integrity is identifying potential threats to integrity. Previously, the threat assessment had not been completed for these pipelines. The owner had performed 6 opportunistic dig inspections near its customer's plant as it was considered a higher consequence area and therefore of higher risk. No corrosion had been identified except for external corrosion at bends with field applied coatings. All the excavated bends were recoated to arrest the corrosion. With the corrosion at bends identified as an issue, it was decided to excavate the first bend about a mile from the upstream plant. This time, a significant amount of external corrosion was found along the straight section of the pipeline that had to be repaired as the anomalies failed the failure pressure criteria of ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines. This unforeseen level of corrosion found on the 34" pipeline resulted in significant delay in selection and deployment of the repair solution. Figure 1 and 2 show the extent of corrosion and the completed repairs.



(a)



(b)

Figure 1. (a) External corrosion observed on the 34" natural gas pipeline, (b) External corrosion observed on the 4" LPG pipeline.

Figure 2. The 34" natural gas pipeline after the repair.

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Threat Assessment

After the pipeline repair, threat assessment was completed followed by risk assessment on both pipelines.
The pipelines were assessed for time-dependent threats (external corrosion, internal corrosion, and stress corrosion cracking), stable threats (manufacturing and construction related defects), and time-independent threats (third party damage and weather-related damage).
Based on the age of the pipelines, available construction records, and history of operation without failure, it was concluded that the main threats associated with the pipelines were external corrosion (major) and stress corrosion cracking (SCC) on the 4” pipeline (minor, based on the low operating pressure of 760 psi). The risk assessment completed based on the identified threats ranked the 4” LPG pipeline at higher risk due to more severe consequence of failure and higher likelihood of failure due to lower wall thickness and higher chance of SCC.

Integrity Management Plan

An integrity management plan was developed in order to reduce the risk of failure on the pipelines. Since external corrosion had been identified as a major threat to the pipelines, it was decided to perform a process similar to external corrosion direct assessment (ECDA) to evaluate the external conditions of the pipeline. The ECDA as per NACE Standard RP0502 has 4 phases:
1. Pre-assessment: In the pre-assessment phase, a detailed study is completed on historic and current data to determine whether ECDA is feasible, define ECDA regions, and select indirect inspection tools. Considering the relatively short length of the pipelines, this step was simplified down to the selection of the indirect inspection tool. The over-the-line survey tool that was selected was Acuren’s Hawkeye™ system; this system is capable of simultaneously acquiring GPS data, depth of cover, current attenuation, close interval potential survey (CIPS), alternating current voltage gradient (ACVG), and direct current voltage gradient (DCVG).
2. Indirect inspection: The indirect inspection step covers aboveground inspections and/or inspections from the ground surface to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity may have occurred or may be occurring. The indirect testing phase includes two or more of the following testing methods:
- CIPS,
- direct and alternating current voltage gradient surveys (DCVG/ACVG), and
- current attenuation.

As mentioned before, the tool selected was capable of performing all of the above at the same time; therefore, CIPS, ACVG and current attenuation testing was completed.
3. Direct examination
After the data from the indirect assessment methods are analysed and reviewed, locations for direct examination are targeted for review and inspection of the following:
- Pipeline coating condition
- Cathodic protection system condition
- Pipeline defects
- Pipeline corrosion damage
- Soil characteristics such as resistivity and pH at pipeline depth

The direction of the project was changed at this point due to an unforeseen event that will be discussed in the next section. As a result, the ECDA digs were not performed.

4. Post assessment: The Post-Assessment Step covers analyses of data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals.

Results of the Indirect Inspection

Pipe-to-soil CIPS was used to evaluate the effectiveness of the cathodic protection system along the length of the pipelines. The cathodic protection was considered effective if it met the -850 mV instant-off potential criterion indicating adequacy of cathodic protection of the pipeline section.
ACVG was also utilized to pinpoint the location of coating holidays. The ACVG survey applies an alternating current signal to the pipeline to create the voltage gradient at the location of a coating holiday.
The results of CIPS and ACVG that were performed on the 4” LPG pipeline is shown in Figure 3. Very similar results were achieved for the 34” NG pipeline.
The results showed the pipeline’s coating was damaged in several different locations. What was more concerning was the fact that the cathodic protection did not meet the -850 mV criterion for a significant length of the pipeline (from ~0.3 miles to ~0.9 miles).
While the pipeline owner was evaluating this result and was planning to perform the verification digs, the 4” pipeline suffered a failure and leaked. The failure was due to external corrosion and its location is shown on the horizontal axis of Figure 3, at about 0.7 miles length. At this point, the location of the failure was exposed and both 4” and 34” pipelines were inspected. As expected from the ACVG survey, the condition of the coating of both pipelines near the failure location was poor, and moderate to severe metal loss had occurred. It was concluded that while both pipelines experienced similar external corrosion mechanisms, the 4” pipeline failed earlier due to the thinner wall thickness. At this point, it was decided that the operations of both pipelines be placed on-hold, until further inspection is completed, and a more detailed action plan is developed to reduce the risk of failure of both pipelines.

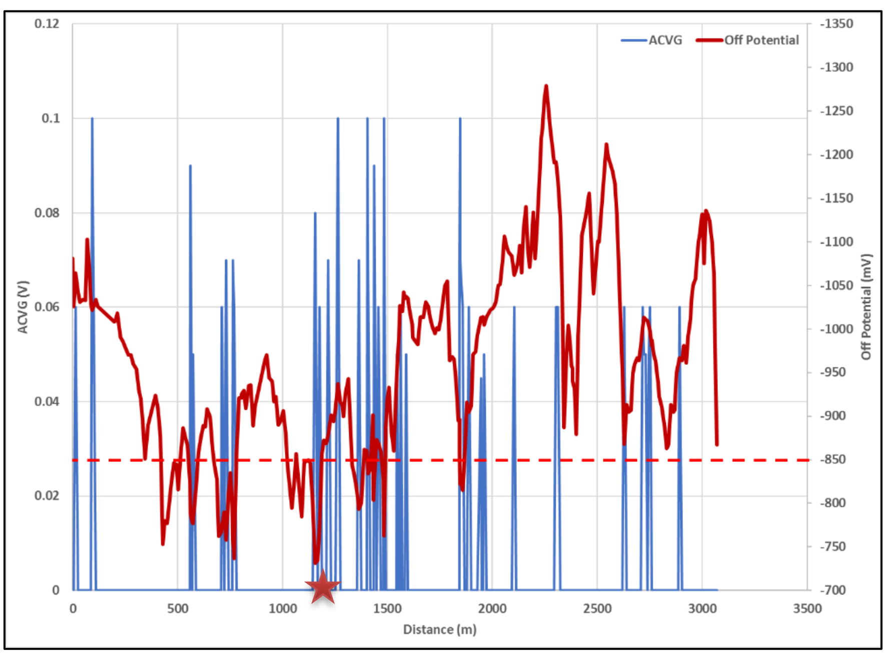

Figure 3. Result of CIPS and ACVG for the 4" LPG Pipeline. The dashed line indicated the -850 mV criterion. The red star shows the failure location.

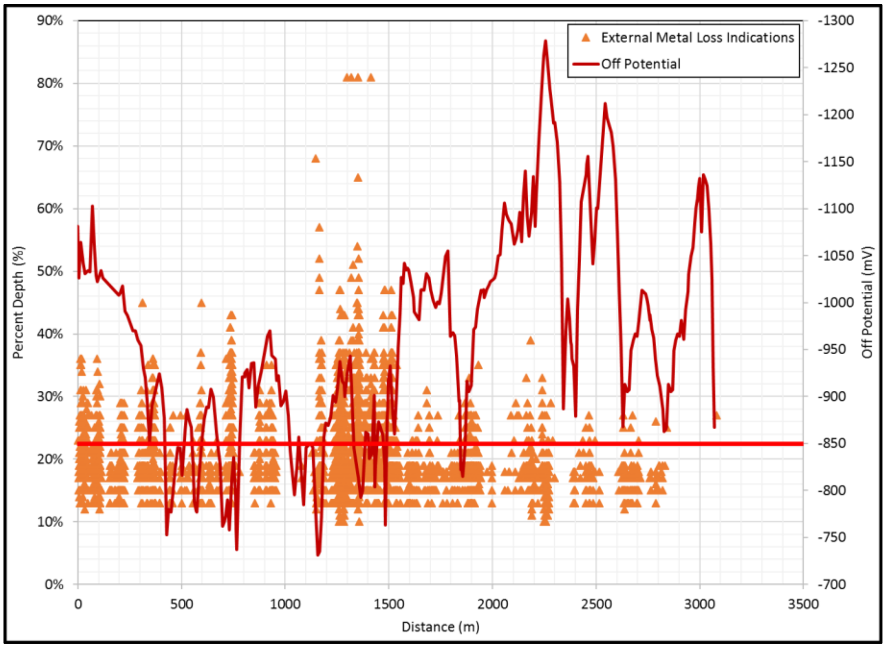

Figure 4. Result of ILI Superimposed by CIPS Data.

In-Line Inspection (ILI)

After the pipeline failure, a high resolution bi-directional magnetic flux leakage (MFL) ILI tether tool was utilized to inspect the 4” pipeline both upstream and downstream of the failure location. Figure 4 shows the results of the ILI. External corrosion was found along the length of the pipeline. In some areas the metal loss was more than 80%.

After alignment of the data from CIPS and ACVG with the metal loss indications from the ILI, it was found that the corrosion was more severe at locations where the cathodic protection did not meet the -850 mV criterion and where ACVG indicated coating holidays (Figure 4).

Repair and Maintenance of the Pipelines

The following are the steps that were planned:

1. Evaluate the ILI data and calculate the probability of leak and burst in the next 10 years.
2. Develop a repair/replacement plan based on the information created in step 1.
3. Perform a root-cause analysis to understand the reason of coating degradation in the same areas on both pipelines.
4. Repair both pipelines in locations where coating was damaged.
5. Perform an ILI on the 34” pipeline in 5 years.
6. Perform annual operational reliability assessment to make sure all the relevant data related to safe operation of the pipeline is captured and reviewed.

The results of the ILI, after completion of verification digs were used to develop an appropriate scope and schedule for maintenance activities along this pipeline system.

This methodology uses Probability of Exceedance (POE) results to determine pipeline specific excavation/repair and re-inspection interval alternatives. The probabilistic methodology takes into consideration such factors as: the inherent tolerances associated with an inline inspection tool and the subsequent growth of the corrosion features identified by the in-line inspection tool.

The POE analysis methods evaluate the probability that, given a pig call, the depth of corrosion is greater than 80% of the wall thickness (potential leak) or the predicted burst pressure using the modified ASME B31G formula is less than the maximum operating pressure (potential pressure failure). The calculation is performed for the “No Repair” scenario first, where POE is calculated for the existing condition of the pipeline. Then a POE criterion is defined, that is the threshold above which the company will repair any anomalies as they grow year after year based on the calculated corrosion rates.

Details of POE methodologies can be found in [1-2]. In this paper, only the result of this analysis is presented as it relates to the maintenance and repair decisions for the pipeline. It was the pipeline owner’s decision to repair any anomaly with POE that was equal to or more than $1x10^{-2}$.

Figure 5 and 6 show the POE-Leak scenarios and POR-Rupture scenarios. The figures show that, with the completion of the repairs each year, the maximum probability of exceedance to 80%WT and rupture is significantly reduced to a level that is tolerable to the company.

A total of 244 indications must be removed/repaired within the next 10 years from the date the ILI was completed in order to keep the risk within a tolerable range for the company. Based on these results, 500 feet of the 4” pipeline was replaced; this significantly reduced the number of digs that were required in the upcoming years.

Root-Cause Analysis

A root-cause analysis was completed to understand the reason for severe external corrosion in some areas of the pipeline, particularly between from ~0.3 miles to ~0.9 miles from the upstream facility.

As mentioned in the System Description section of this article, both pipelines received cathodic protection from an impressed current system located at both end of the pipelines and annual cathodic protection surveys showed that the structure to electrolyte potentials surveyed met the -850 mV instant-off polarized criterion at test stations; test stations were located at either ends of the pipelines. However, the CIPS showed that, in most of the range where severe external corrosion was found, the -850 mV instant-off polarized criterion was not met.

Review of the historical records regarding the changes around the route of the pipeline showed that several construction projects along the length of the pipeline had taken place and had completely changed the soil conditions around the pipelines. As a result, and to protect the pipeline, more current output would have been required. However, since the test stations were located near the rectifiers at either ends of the pipelines, they had always showed that the pipelines were receiving adequate cathodic protection.

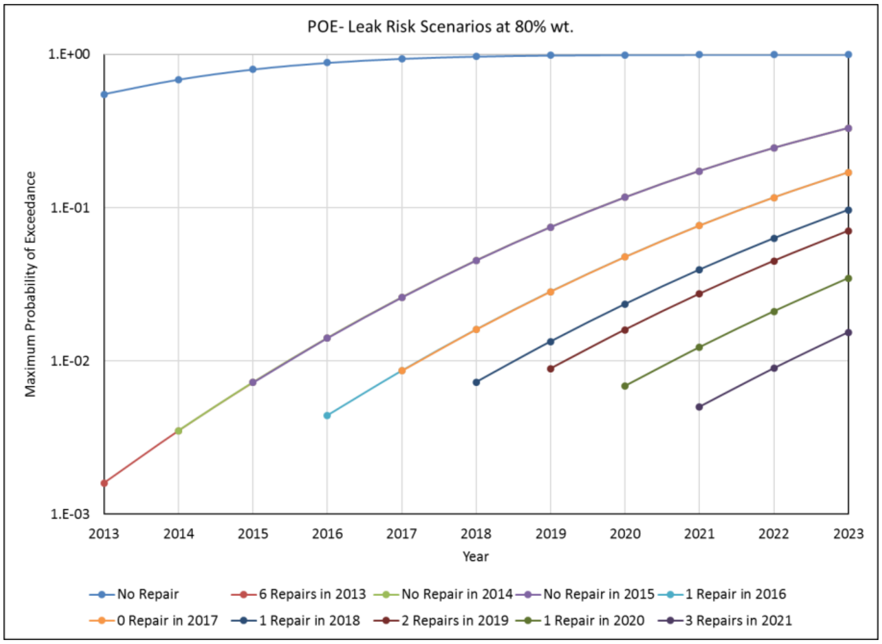

Figure 5. POE-Leak Risk Scenarios

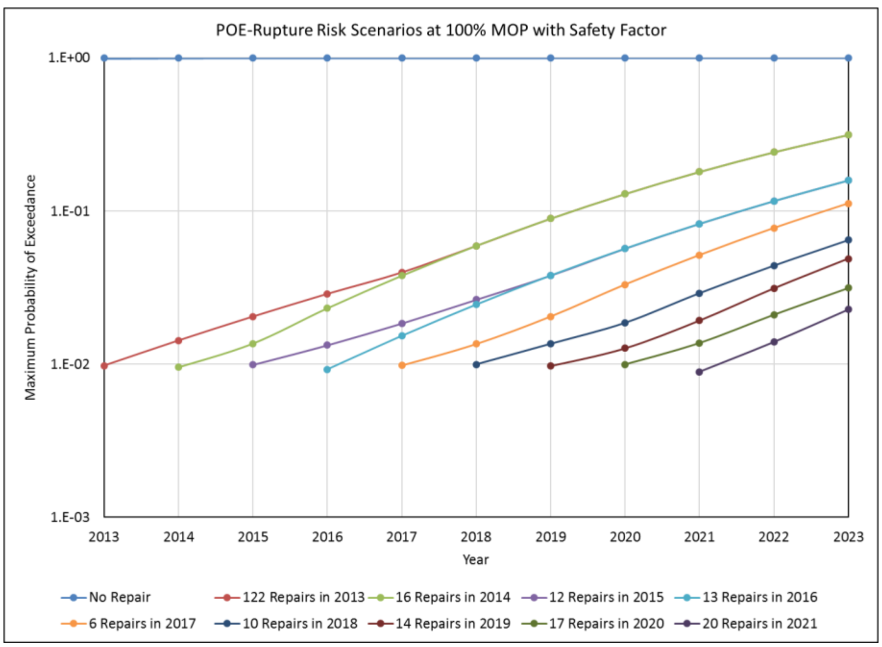

Figure 6. POE-Rupture Scenarios

Summary

One of the core elements of a pipeline integrity management program is the effective management of hazards as part of the risk management process. The first step of this process is to understand the hazards followed by development of proper monitoring, inspection and mitigation plans. Not following these steps may be very costly. This case study presented a case in which this important step was not originally followed, which resulted in misallocation of resources in some redundant inspections, and eventually pipeline failure due to delay in execution of proper steps.

Over the line cathodic protection surveys (CIPS and ACVG) were found to be very effective in identifying locations where degradation is expected. The results showed close correlation to the in-line inspection results. A cost-effective and detailed long-term repair and maintenance plan was developed to maintain the integrity of the pipelines.

References

1. D. C. Johnston and C. E. Kolovich, “Using a Probability Approach to Rank In-line Inspection Anomalies for Excavation and for Setting Reinspection Intervals”, API's 51st Annual Pipeline Conference & Cybernetics Symposium, (2000).
2. R. G. Mora, P. H. Vieth, C. Parker, and B. Delanty, “Probability of Exceedance (POE) Methodology For Developing Integrity Programs Based on Pipeline Operator-Specific Technical And Economic Factors”, 4th International Pipeline Conference, IPC2002-27224, (2002).