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USE OF AN INTERNAL CORROSION THREAT ASSESSMENT TO IDENTIFY LOCATIONS TO CONDUCT AN INTEGRITY ASSESSMENT

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ABSTRACT

In the United States, federal regulations require that jurisdictional pipelines for which the threat of internal corrosion exists be assessed by in-line inspection (ILI), hydrostatic pressure testing, Internal Corrosion Direct Assessment (ICDA) or another method to assure their integrity. Removing the threat of internal corrosion can be justified if sufficient historical data on gas quality, monitoring, and/or inspection exists. A need therefore exists for a technically defensible and systematic process by which the internal corrosion threat can be determined. This paper describes a standard approach to organizing, integrating and analyzing data to identify whether internal corrosion is a threat for a given pipeline segment. A case study illustrating the implementation of the approach is also provided.

Key Words: Threat assessment, internal corrosion, data integration, direct evidence, pipelines, indirect data.

INTRODUCTION

Internal corrosion threat assessment is a systemic, analytical process that can be used to determine the degree of the threat of internal corrosion for a pipeline or pipeline system. Corrosion is more likely to occur under certain pipeline design and operating conditions that promote specific internal corrosion threats. The nature of the conditions that promote these threats can be defined. Data can then be analyzed to determine whether any of the potential threats exist in the present or existed in the past. Direct information from non-destructive examinations may be used to verify whether internal corrosion has occurred at representative locations, thereby verifying the threat. If direct information reveals that no corrosion has occurred due to a specific threat mechanism, and no corrosion is actively occurring at present, then it is unlikely that the specific threat has resulted in metal loss at similar locations. Where direct evidence verifies the presence of internal corrosion, an integrity assessment[1,2] is then required. The steps involved in the internal corrosion threat assessment process are: data collection, system segmentation, gap analysis, threat ranking, direct evidence verification, and integrity assessment method selection.

This paper discusses the process by which an internal corrosion threat assessment is performed. A case study is then presented to illustrate the process on a natural gas pipeline system. The threat assessment was performed on thirty-one (31) pipelines within the system. As a result of the threat assessment process an integrity assessment was only performed on five (5) lines within the system (as opposed to all 31). Regulator acceptance of the methodology for performing the threat assessment detailed in this case study was obtained.

INTERNAL CORROSION THREAT ASSESSMENT PROCEDURE

Data Collection

Current and historical data regarding the operation of a pipeline system, as well as any known occurrences of internal corrosion provide information related to the potential threat of internal corrosion. It is important to obtain as much information as possible prior to performing a threat assessment. Data that is collected can be divided into two categories – direct evidence and indirect information[3]. Direct evidence is defined as data such as visual inspections, ILI, non-destructive testing (NDT), or coupon results[4] (if interpreted properly) that documents physical changes to the pipe due to corrosion. Direct evidence may also document that corrosion has not occurred. Indirect information is defined as data that indicates the potential for corrosion to occur; not that corrosion has actually occurred. Indirect information includes: gas analyses, liquid and solid composition analyses, bacteria analyses, flow conditions, and operating parameters. Where data is not available, (e.g., historical operating conditions or practices) the lack of information may result in a more conservative (higher) threat ranking.

The type of data that is collected can be divided into ten categories: pipe material and construction, operation and maintenance, gas composition, liquids, solids/sludge, mitigation history, monitoring history, non-destructive examinations, visual inspections, integrity assessments, and leak/failure history. Both direct evidence and indirect information are collected in these categories.

As data is collected, logical means of segmenting the pipeline system begin to emerge.

Pipe Material and Construction. The material and construction of the pipe can play a role in the susceptibility of a pipeline to internal corrosion. It is important to collect information regarding the construction of each pipeline such as material of construction, year manufactured, nominal diameter, nominal wall thickness, and longitudinal seam type. Typically, gas pipelines are pressure tested prior to installation, so the test medium (water or other) should be considered as well.

Operation and Maintenance. The operating condition of the line (i.e., pressure, temperature, flow rate) affects the susceptibility of a pipeline to corrosion by affecting where and if liquid accumulation and/or water vapor condensation will occur. Additionally, standard maintenance activities such as drip blowing, pig cleaning, etc. can provide information regarding the potential for internal corrosion to occur.

Gas Composition. Internal corrosion cannot occur if water (or other electrolyte) is not present. However, in the presence of water, gas constituents such as CO_2, H_2S, and O_2 are potentially corrosive. Additionally, if the pipeline is operating below the water dew point temperature, water vapor in the gas may condense on the pipe walls. If landfill gas/coal bed methane or manufactured gas have ever been transported or air has ever been injected, the pipeline may have increased levels of potentially corrosive constituents.

Liquids. Liquids may exist in a pipeline system through process upsets, from liquid entry at a gas supply point, or condensation of water vapor. The presence of liquids may be identified or detected in drips, scrubbers, separators, metering and regulating equipment, and pigging operations. If free water is present in the collected liquids, there is the potential for internal corrosion to occur.

Solids/Sludge. Solids may be observed in, or removed from, a pipeline through drip blowing, pigging operations, and internal inspections. Solids can pose a potential threat for internal corrosion. They may contain, trap, or absorb water/moisture possibly leading to under-deposit corrosion. Solids in the form of nodules or tubercles are locations where localized corrosion may occur.

Mitigation History. Mitigation may have been performed in order to control (or minimize) internal corrosion that was occurring in an IC Segment. There are chemical, mechanical, and design methods of mitigation.

Monitoring History. Any time that corrosive gas is being transported through a pipeline and mitigation is being applied, the effectiveness of the mitigation may be monitored. This monitoring may be performed using monitoring devices. Monitoring devices may also be used to evaluate a pipeline for the presence of internal corrosion. The results from monitoring devices provide information about corrosion that occurred at the location and during the time period that they were installed. If interpreted correctly[5,6], coupon monitoring results can provide direct evidence that internal corrosion has occurred in a pipeline.

Non-Destructive Examinations. Non-destructive examinations such as ultrasonic thickness measurements or radiography provide direct evidence regarding whether or not internal corrosion has occurred at a given location by identified locations of reduced wall thickness. NDE methods do not, however, distinguish between active and in-active corrosion.

Visual Inspections. A visual inspection may be performed when the inside surface of the pipe is exposed. This visual inspection provides direct evidence regarding whether or not internal corrosion has occurred in a pipeline. If internal corrosion is observed, it may be possible to identify the type of corrosion (i.e., general etching or pitting). Information may also be collected regarding the presence of any liquids or solids such as scale, deposits or black powder. Both non-destructive examination and visual inspections provide valuable insight as to the overall internal condition of the pipeline segment, especially if conducted on susceptible pipeline features, such as drips, offsets, dead legs, or low points. This information may be used to validate or eliminate the threat of internal corrosion within areas with limited indirect evidence as part of the Direct Evidence Verification, as discussed below.

Integrity Assessments. Hydrostatic testing may be performed any time that a line is put into or returned to service, or it may be used as an integrity assessment method. After hydrostatic tests are performed, any water that remains in the line may increase the potential for internal corrosion to occur. In-line inspection tools may be used to identify locations of internal indications. High resolution tools are capable of distinguishing between external and internal indications and can provide direct evidence that internal corrosion has occurred. Detailed examinations performed as a part of an Internal Corrosion Direct Assessment (ICDA) can also provide direct evidence regarding whether internal corrosion has occurred in a pipeline.

Leak/Failure History. Leaks or failures that have been caused by internal corrosion provide direct evidence that internal corrosion has or may be occurring in the pipeline. Unless pipeline operations have changed since the leak or failure, the potential for internal corrosion to occur on the line may still exist.

System Segmentation

After data is collected, the pipeline system is segmented. Data collected regarding system operations and history of corrosion is used to create IC Segments, which are used throughout the threat assessment. An IC Segment is defined as a portion of a pipeline system, which may or may not be continuous, that has experienced the same or similar conditions related to internal corrosion based on its current and previous operating history. IC Segments may be identified based on gas sources, age, and design/construction factors such as drips. Once IC Segments are created, data is collected for each IC Segment.

Gas Sources. The threat for internal corrosion may vary based on the source of the gas being transported by a line. Some gas sources may be relatively dry whereas others may contain large amounts of water vapor or free liquid hydrocarbons. Additionally, some gas sources may contain larger amounts of potentially corrosive constituents such as oxygen, carbon dioxide, and hydrogen sulfide. An equally important consideration is the evaluation of all prior sources and any known changes in the supply gas. Creating IC Segments based on gas sources allows grouping of lines or areas that have experienced the same or similar threat to internal corrosion based on the gas being transported.

Age of Pipeline. Corrosion is a time dependent threat; therefore older pipes may be likely to have a higher threat for internal corrosion. Creating IC Segments based on the age of the pipe allows grouping or lines or areas that have experienced the same or similar operating conditions.

Design/Construction Factors. Lines or portions of lines that have unique conditions may be considered a separate IC Segment. For example, if only one line or area contains pipeline drips, this line/area may be considered its own IC Segment. Other examples of pipeline design/construction features that may constitute a separate IC Segment if they are only present in a portion of a system include: offsets, joint couplings, separators (at the beginning of the line), and dead legs.

Gap Analysis

After performing the data collection and system segmentation, it may be apparent that certain data is missing. In some cases, missing data may be identified and obtained. In other cases, such as with historical operating conditions, it may not be possible to obtain missing data. Data gaps can be addressed through interviews, field visits, and sample collection. Performing interviews, especially with field personnel, may identify information that is not otherwise documented. A field visit may be helpful in identifying some unknown information. In particular, a field visit may help identify low spots, road/river crossings, pig launchers/ receivers, and possibly drips. If liquid sample collection has never been attempted or samples collected have never been tested for the presence of water, sample collection may be attempted from any locations where liquids may be present. Sample collection does not provide any information regarding historical conditions of the IC Segment.

Threat Ranking

The data collected is used to rank an IC Segment for the threat of internal corrosion. Internal corrosion leaks or failures, visual examinations, and other forms of direct evidence may verify whether internal corrosion has, or is currently occurring in a particular IC segment. Direct evidence may also verify that internal corrosion has not occurred in an IC segment. In the absence of direct evidence, indirect evidence and (current and historical) pipeline operation and maintenance practices can be used to assess or rank the potential for internal corrosion. Corrosion cannot occur in the absence of water (or other electrolyte); therefore, particular emphasis is placed on discerning whether or not water is, or may have ever been, present in the line. The threat of internal corrosion for each IC Segment is classified as Low, Medium, or High.

If an IC Segment has direct evidence that internal corrosion has occurred, the IC Segment is classified as having a High threat of internal corrosion. If indirect evidence and operation and maintenance practices are being used to rank the threat of internal corrosion, a series of questions are answered regarding the current and historical operation of the IC Segment. Each question is answered with a ‘Yes’, ‘No’, or ‘Unknown/No Data’ response. In general, documentation is needed in order to answer ‘No’ for any given question; ‘Unknown\No Data’ is the appropriate response when historical records do not exist for a given question. The number of ‘Yes’, ‘No’ and ‘Unknown/No Data’ responses are tallied. A simple matrix can be used to determine the threat of internal corrosion. In order for an IC Segment to be assigned a ‘Low’ threat, a large amount of information needs to be known and documented regarding the IC Segment. An example of a simple IC Threat matrix is discussed during the case study.

Direct Evidence Verification

Direct evidence is needed to verify the threat of internal corrosion for all IC Segments identified as having a Medium or High threat. The purpose of obtaining direct evidence is to validate the threat ranking. Direct evidence may include NDE or visual examinations. Direct evidence should be obtained at a location determined to have a similar or more severe environment than the remainder of the IC Segment (e.g., drip or low spot). Any time that direct evidence verifies the threat of internal corrosion, the ranking assigned (Medium or High) should be considered valid. An integrity assessment should be performed on the IC Segment.

Direct evidence may identify that internal corrosion has not occurred. In such cases, the threat may be re-ranked as Low, and further integrity assessment is not required.

CASE STUDY

An internal corrosion threat assessment was performed on transmission piping that formed a network consisting of multiple supply points and bi-directional flow. The majority of the system was not piggable and performing ICDA on the entire system would have been costly due to the numerous interconnects and outlets. Therefore, a need existed to determine, and possibly limit, the locations within the transmission system where an integrity assessment needed to be performed. Regulator acceptance was gained for the methodology for performing the threat assessment detailed in this case study. The threat assessment process was used to eliminate twenty six lines with a low threat of internal corrosion from the ICDA program.

Data Collection

The original line in the transmission pipeline system that was being assessed was installed in 1950. The system has continued to expand since 1950, with lines installed as recently as 2003. There are three sources of gas to the pipeline system. Historically gas that was cracked using water and air to create approximately 550 Btu gas was transported. This gas was interchangeable with the manufactured gas being transported by the distribution system. There was also a period of sixteen years during which air injection was used for Btu stabilization. All of the pipelines within the system contain offsets at road crossings. None of the lines have an internal coating or lining, and they have not previously been used for liquid service. The pipelines typically operate at pressures ranging from 1930.5 – 2068.5 kpa (280 – 300 psi) and temperatures ranging from 4.4 – 26.7℃ (40 – 80℉). The maximum gas velocity expected within the pipeline system during the winter months is 10.4 m/s (34 ft/s). All of the lines within the system may have periods of low or no gas flow. Average gas composition measurements obtained during 2004 and 2005 showed less than 1 mol% CO_2, less than 0.5 ppm H_2S, and less than 7.5 lbs/mmscf H_2O.

No form of chemical treatment has been applied to any of the system. No monitoring devices have ever been used in the system. No integrity assessments have been performed in the system. Hydrostatic pressure test were performed at the time each line in the system was installed. The following line/area specific data was also collected.

The original line (Line I) in the system contains Dresser couplings. The only visual inspection on the line was performed when a dresser coupling was removed. No internal corrosion was identified during the inspection. Liquids have been removed from Line X at a scrubber within a gate station. The liquids were not tested for the presence of water. Black sludge of an unknown volume was recovered once from a second separator at a different location.

The only drips within the system are located along two continuous lines (Line II and Line III). The lines contain sixteen (16) low point siphons and nine (9) drip logs. Two leaks have occurred on these lines, one in 1985 and the other in 1997. Both leaks occurred in drips. Drip blowing has been performed annually since 1998. Liquids have been removed from all drips except for two. Prior to 1998, liquids would have sat stagnant in the drips for numerous years. Four (4) drips have been removed and examined since 1998. Internal corrosion was observed at two of the locations. Line II and Line III are the only lines in the system where internal corrosion leaks have occurred and where internal corrosion has been observed.

Only a portion of one line in the system (Line IV) is piggable. A low resolution in-line inspection (ILI) was performed in 1999. Verification digs were performed at several locations to validate the ILI results; no internal corrosion was identified at any of these digs. A high resolution ILI was performed on the piggable portion of Line IV in 2006. All internal indications were less than 10% of the wall thickness. Verification digs were performed at external indications to verify the 2006 ILI results. The line was pig cleaned prior to performing the ILI. Approximately twenty-five (25) gallons of solids were recovered during pig cleaning. A video inspection was performed at a water crossing; the inspection indicated the presence of a black oily substance on the pipe surface. In 2005, prior to the video inspection two liquid removal lines were removed from inside Line IV at the water crossing. These lines were covered in a black oily substance, but no corrosion was present.

In the late 1980's and early 1990's, large volumes of liquid hydrocarbons were recovered from a gate station located in the western portion of the system. There are several lines that feed into and out of this gate station. No liquids have been recovered at this location for the past ten (10) years. The liquids removed were not tested for the presence of water. In 2006, a NDE was performed on Line V, which transports gas received at this gate station. No internal corrosion was identified from the ultrasonic thickness measurements.

IC Segmentation

The transmission piping being assessed was split into seven (7) different IC Segments, which were each given a letter designation A through G. There are three gas sources to the system, which will be referred to as Source 1, Source 2 and Source 3.

IC Segment A was comprised of the oldest line (Line I) in the system. The was installed in 1950, experiences bi-directional flow and transported gas that was blended with air for heating value (Btu) stabilization over a period of sixteen (16) years.

IC Segment B was comprised of five (5) lines that have transported gas from all sources to the system. The lines transported cracked (manufactured) gas for six (6) years after they were initially installed and gas that was blended with air over a period of sixteen (16) years. The only drips in the system are present on these lines (Line II and Line III).

IC Segment C was comprised of two (2) continuous lines that predominantly transport gas from only Source 1. The upstream line in the IC Segment was the only line in the system that has been inspected using In-Line Inspection (ILI) tools (Line IV).

IC Segment D was comprised of lines eleven (11) lines that were installed between 1957 and 1968. These lines historically predominantly transported gas from Source B, but they currently transport gas from all three sources. Also, like IC Segments A and B, the lines transported gas blended with air.

IC Segment E was comprised of nine (9) lines that were installed after 1991 and have predominantly transported gas from Source 3, which is reported to be extremely dry. These lines have never transported gas that was blended with air.

IC Segment F was comprised of two (2) lines that were built in the late 80's and early 90's. They transported gas from Source 1 for a short period of time, but have transported predominantly Source 3 gas for the majority of their time in service. These lines have never transported gas that was blended with air.

IC Segment G was comprised of one (1) line that was installed in 1957 and received gas from Source 2. The IC Segment is currently bi-directional.

Gap Analysis

After the data collection process was complete, all unknown data elements were identified. Company personnel obtained historic company newsletters that helped identify the time period during which cracked (manufactured) gas was transported. Additionally, subject matter experts (SMEs) were interviewed in order to identify any remaining information available regarding the IC Segments.

Threat Ranking

IC Segment B was the only IC Segment with direct evidence that internal corrosion had occurred. IC Segment B was assigned a 'High' threat for internal corrosion. Indirect evidence was used to rank the remaining IC Segments. Questions were answered regarding the presence of liquids, water, or solids. Additionally, questions were answered regarding the potential for water condensation and the presence of joints that couple dissimilar metals or that create crevices. Questions were asked regarding the age of the IC Segment, the presence of drips or offsets, any previous service of the line, the use of chemical treatment, corrosion monitoring rates, and hydrostatic pressure testing practices. Finally, questions were answered regarding gas composition such as the use of air injection, the presence of landfill or manufactured gas, CO_2 partial pressures, and H_2S and O_2 levels.

The tally of the 'Yes', 'No', and 'Unknown/No Data' responses for each IC Segment are shown in Table 1. These responses were compared to the IC Threat Ranking matrix to determine the IC threat ranking. IC Segment A, IC Segment C, IC Segment D, and IC Segment G were assigned a 'Medium' threat for internal corrosion. Direct evidence verification was necessary for these IC Segments in order to determine if internal corrosion is a valid threat for the IC segment. IC Segment E and IC Segment F were assigned a 'Low' threat for internal corrosion. No further action was required to assess these IC Segments.

Direct Evidence Verification

An offset on IC Segment A was excavated and inspected using ultrasonic thickness measurements and radiography. No internal corrosion was observed during the examination. Direct evidence did not support a 'Medium' ranking; therefore, the IC Segment was re-ranked as having a 'Low' threat of internal corrosion.

Direct evidence exists for IC Segment B to validate the threat of internal corrosion. There have been two leaks in drips and drip risers that have been attributed to internal corrosion. In addition, visual and non-destructive examinations have also identified the existence of internal corrosion. An integrity assessment is required for IC Segment B.

An in-line inspection was performed on a large portion of IC Segment C. ILI verification digs that have been performed since the 1999 inspection have only identified external corrosion. All internal indications from the 2006 ILI inspection were less than 10% of the wall thickness. Verification digs on external indications were used to validate the 2006 ILI results. Finally, the video camera examination of a water crossing, as well as the visual examination of liquid removal lines installed in the line at the water crossing, failed to indicate that internal corrosion was present. Direct evidence did not support the 'Medium' ranking assigned to the IC segment;

therefore, IC Segment C was re-ranked as ‘Low’. No further action is required to assess this IC Segment.

On IC Segment D, a non-destructive examination was performed on an offset using ultrasonic thickness measurements and radiography. This offset was located at a low point where any liquids present in the IC Segment were expected to accumulate. No internal corrosion was discovered during the examination of the offset. Direct evidence did not support a ‘Medium’ ranking; therefore, IC Segment D was re-ranked as ‘Low’. No further action is required to assess this IC segment.

An offset on IC Segment G was excavated and inspected using ultrasonic thickness measurements and radiography. No internal corrosion was observed during the examination Direct evidence did not support a ‘Medium’ ranking; therefore, the IC Segment was re-ranked as having a ‘Low’ threat of internal corrosion.

A summary of the final rankings after the direct evidence verification is provided in Table 2.

CONCLUSIONS

An internal corrosion threat assessment provides a systemic, defensible approach to determining whether or not the threat of internal corrosion exists on a pipeline. The process relies upon current and historical data regarding the pipeline system. Where insufficient data is available to justify the elimination of an internal corrosion threat, an IC Segment is assigned a conservative ranking of ‘Medium’. Direct evidence (i.e., pipe examinations) is then required to validate the threat of internal corrosion. The internal corrosion threat assessment process allows pipelines to be grouped in a logical manner. The case study discussed highlights some of the benefits of performing an internal corrosion threat assessment. The assessment was performed on thirty-one (31) pipelines. As a result of the threat assessment, five (5) lines representing approximately 10 percent of the total length transmission lines in that geographical region were identified as requiring an integrity assessment. This reduction in the number of lines that required an integrity assessment for internal corrosion is not only an economic benefit, but it also allowed the operator to focus on the lines that where internal corrosion was most likely to exist.

REFERENCES

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Table 1. Threat Ranking

IC Segment	Tally of Responses to Threat Ranking Questions			Threat Ranking
	Yes	No	Unknown/No Data	
A	6	6	6	Medium
B*	N/A	N/A	N/A	High
C	4	8	8	Medium
D	5	7	6	Medium
E	1	9	8	Low
F	1	9	8	Low
G	4	8	6	Medium

*Direct evidence that internal corrosion had occurred was present for IC Segment B; therefore, the IC Segment was automatically assigned a ‘High’ threat ranking.

Table 2. Threat Assessment Summary and Re-Ranking

IC Segment	Initial Threat Ranking	Direct Evidence Verification	Final Ranking	Follow-On Action
A	Medium	UT measurements at offset verify no IC	Low	Perform P&M to monitor condition
B	High	None required	High	Perform integrity assessment
C	Medium	ILI results show no IC indications greater than 10%	Low	Perform P&M to monitor condition
D	Medium	UT measurements at offset verify no IC	Low	Perform P&M to monitor condition
E	Low	None required	Low	Perform P&M to monitor condition
F	Low	None required	Low	Perform P&M to monitor condition
G	Medium	UT measurements at offset verify no IC	Low	Perform P&M to monitor condition