Internal Corrosion in Pipeline Facilities

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1 Introduction

In January 2022, API published Recommended Practice 1188, *Hazardous Liquid Pipeline Facilities Integrity Management*, 1st Edition [1]. Internal corrosion is one of the primary threats identified in API RP 1188 as having the potential to impact onshore hazardous liquids pipeline facility integrity. Due to the increased prevalence of internal corrosion within facilities (relative to internal corrosion in transmission pipelines) and the challenges in performing facility piping inspections because the majority of the piping is unpiggable, this technical report provides an overview of internal corrosion threats within facilities and guidance on threat management and mitigation. A few case studies are provided to showcase where internal corrosion failures within facilities have occurred; lessons learned from those incidents; and how operators are evaluating and addressing the threat.

2 Background Information

The 2016 API Pipeline Performance Tracking System (PPTS) advisory *Operator Advisory on Facilities Piping and Equipment* indicated that most releases that occur at pipeline facilities are small (i.e., ≤ 5 BBLs) [2]. This trend is true both for facilities incidents overall and failures specifically related to internal corrosion. API data from 2010 to 2021 indicate that over half of the internal corrosion failures have been ≤ 5 BBLs [3].

There is no discernable trend in the number of internal corrosion failures from 2010 to 2021. There was an increasing trend through 2015, with the trend decreasing slightly over the next few years, followed by a minor increasing trend for a few years. The lack of trending is likely due to a combination of improved corrosion control/ management measures and increased emphasis on internal corrosion as a primary threat within facility piping in the past decade, being counteracted by the progression of corrosion within aging facilities (since corrosion is a time-dependent threat).

According to the 2016 PPTS Advisory, at least 50 % of facility releases caused by internal corrosion occurred at a low point in the facility pipe. This trend has continued, with 73 % of internal corrosion incidents from 2010 to 2021 being identified as occurring in low points.

Between 2010 and 2021, there was a significantly larger percentage of internal corrosion related failures on large diameter piping within facilities (i.e. ≥ 24 in.) than external corrosion failures on large diameter piping. During that period, 8 % of the external corrosion failures were on piping ≥ 24 in., compared with 24 % of internal corrosion failures on piping ≥ 24 in. In comparison, 29 % of external corrosion failures were on piping < 8 in. in diameter, whereas 11 % of internal corrosion failures were on piping < 8 in. in diameter. While the total distance of facility piping of each diameter is not known, the fact that there is a higher percentage of failures caused by internal corrosion on large diameter versus smaller diameter could indicate that diameter plays a role in the potential for internal corrosion to occur within facilities. This is likely related to the impact of diameter on flow velocity and thus the decreased ability to entrain or sweep water and solids with increasing pipe diameter.

API data [3] indicate that for 68 % of internal corrosion failures, visual inspection results showed localized pitting (versus general corrosion). The predominance of localized corrosion is not surprising, given that most internal corrosion mechanisms manifest as localized versus general corrosion. By cause, 47 % of internal corrosion was attributed to microbiologically influenced corrosion (MIC); 37 % to water dropout/acid; 7 % to corrosive commodity; and 1 % to erosion. The remaining was attributed to “other.”

As shown in Figure 1, a review of internal corrosion failures that occurred between 2010 and 2021 relative to the decade of installation shows that of known pipe installation years, pipe installed in the 2010s had the highest number of failures, with almost 40 % more than the next highest category (44 versus 32). This suggests that:

1) internal corrosion is not being adequately addressed as new piping or facilities are being installed;

2) internal corrosion failures within facilities can occur at locations where high corrosion rates exist; or

3) the “fresh” surface condition of more recently installed piping is more susceptible to internal corrosion.

Note that 2010 to 2021 also corresponds to a time of increased fracking activity when numerous new crude storage facilities were built across the United States.

The decade with the next-highest number of failures within known pipe installation years was the 1950s. This trend is more consistent with corrosion being a time-dependent threat, which should result in more failures for older pipe. As discussed below, the data are not normalized to account for factors like wall thickness and length of pipe in facilities for each decade, as well as other parameters.

The number of failures with unknown installation years was similar to those installed in the 2010s (i.e., the decade with the highest failures). Given modern data retention emphasis, it is more likely that those “unknown” failures were from older pipe rather than newer pipe, meaning that the installation year with the highest number of failures is potentially from a different decade. However, given the high number of failures from 2010 installation and that the “unknown” data could be spread over multiple decades, this is not an overwhelming conclusion that could be drawn.

The failure data are not normalized for the total length of pipe from each decade present within facilities, and it is possible that normalization would suggest different trends. Additionally, wall thickness was not considered as part of the trending analysis, and it is possible that the wall thickness being used has changed over time, resulting in different failure times for similar corrosion rates.

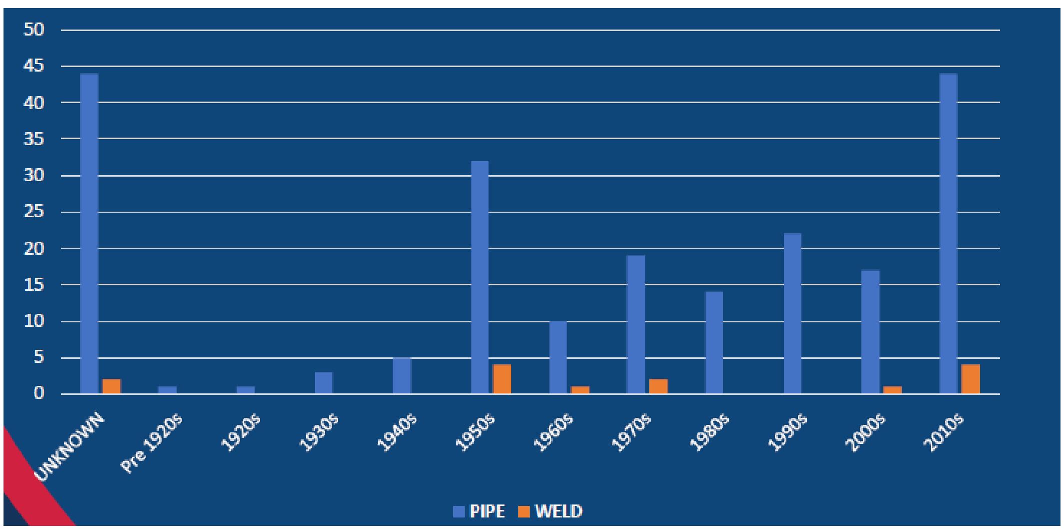

Figure 1—Internal Corrosion Failures by Decade of Installation

Finally, most internal corrosion failures within facilities occurred at locations where inspections have not previously been performed. Only one failure location was identified as having had a previous inspection in the most recent API data [3].

Recommendations from the 2016 API PPTS Advisory [2] include:

— draining and isolating dead legs in crude oil service that serve no further process purpose;

— developing a phase-out plan for systematically removing these dead legs;

— creating a maintenance schedule for flushing dead legs and intermittently used lines with fluids that contain biocide(s) to inhibit microbial growth and reduce the threat of internal corrosion;

— incorporating a dead-leg program within the facility;

— incorporating a piping inspection program within the facility that includes piping elevation as a variable to address low spots.

Additionally, a 2014 API PPTS Advisory [4] recommended, where feasible, to consider the use of internal liners as a preventive and mitigative measure to minimize internal corrosion as an integrity threat.

PRCI document PR-186–113718, *Facility Integrity Management Program Guidelines* [5], identifies an approach to facility integrity management similar to API RP 1188. Within the PRCI document, internal corrosion is one of the identified integrity threats, and the following measures are mentioned for consideration:

— sampling and analysis;

— corrosion rate monitoring;

— inspection;

Additionally, within the appendix of PR-186–113718, it is identified that special attention may need to be paid to dead legs, relief lines, and low-flow piping. The appendix determined that dead-leg management programs should address identification of dead legs; removal where possible; and evaluation of fitness for service for dead legs left in operation.

3 Internal Corrosion Threat Analysis and Corrosion Prediction

NACE SP0106–2018, *Control of Internal Corrosion in Steel Pipelines* [6], discusses several factors that impact the threat of internal corrosion. These include the presence of water, potentially corrosive gases, organic acid, sulfur, chlorides, microorganisms, solids, flow velocity effects, and temperature effects. Several of these factors are discussed below. Based on the incident data for failures that are due to internal corrosion, there is a higher potential for internal corrosion for facility piping transporting crude oil than those transporting highly volatile liquid (HVL), refined product, or supercritical carbon dioxide (CO_2). The higher potential is based on the increased corrosivity of contaminants in the crude oil, the potential for underdeposit corrosion formation, and microbiologically influenced corrosion (MIC), as well as other corrosion mechanisms that could be present depending on the environment. Similarly, piping transmitting CO_2 can experience extremely high corrosion rates if free water is present because of the high partial pressure of CO_2.

3.1 Fluid Corrosivity

Fluid corrosivity is a term that can be used to include the presence of water (i.e., the water cut) and the organic acid and chloride composition present within the water. Additionally, while it is not always considered, liquid products can still contain a sufficient amount of dissolved gas (e.g., carbon dioxide and hydrogen sulfide) that increase the threat of internal corrosion. The amount of dissolved gas within the hydrocarbon liquid and the operating pressure will determine the potential dissolved gas content of the water phase. See Section 3.4 for additional information regarding specific dissolved gases.

For CO_2 pipelines operating in supercritical phase, trace amounts of impurities (e.g., water, organic matter, O_2) will not pose a significant internal corrosion integrity threat as long as they are kept dissolved in the dense phase. Reactions between H_2O, SO_x, NO_x, O_2, and H_2S can produce a separate phase containing highly corrosive acids (HNO_3, H_2SO4) and/or elemental sulfur even when the supercritical CO_2 has water content well below its saturation limit. Monitoring the pipeline feed composition and controlling the concentration of impurities entering the pipeline system should be included as a facility integrity management strategy. General guidance on the allowable upper limits to prevent corrosion is available in DNV-RP-F104–2021, *Design and Operation of Carbon Dioxide Pipelines* [7], but it is generally recommended that the CO_2 specification of each carbon capture and storage (CCS) project be further optimized using validated models or laboratory testing.

3.2 Underdeposit Corrosion

Underdeposit corrosion (UDC) can occur within facility piping based on the volume and composition of solids present. Within liquid systems, wax and asphaltenes deposition (organic deposits) can be an issue, along with a mixture of corrosion product and sand or other solids (inorganic deposits) transported. When the solids transported are mobile, they are commonly referred to as sludge. However, without sufficient flow, these solids can settle and accumulate within piping. Over time, this can result in the formation of a thick, adherent mass. There are different mechanisms by which UDC can occur. One mechanism is when an anode is created beneath the deposit and crevice-type corrosion occurs, driven by the differences in chemistry under and outside of the deposit. A second mechanism is when local cathodes and anodes are formed under the deposit and corrosion is driven by differences in solids composition. The third mechanism is when uniform corrosion that occurs under a deposit (such as a hygroscopic salt) where water becomes trapped against the steel surface that otherwise would not be exposed to an electrolyte [8].

To understand the potential for UDC, the type of solids present within a facility needs to be characterized. Knowledge of solids composition (e.g., sulfur, salt, sand, asphaltene) is needed to have a general understanding of the corrosivity of the solids, and information regarding solid characteristics, such as particle size and shape, is necessary to perform solids flow modeling. Solids flow modeling can be used to determine where solids are dropping out from hydrocarbon liquid and/or being held up within the piping; however, while solids flow modeling can be a helpful tool, it is not necessarily a common practice for facility piping. NACE SP0208–2008, *Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines* [9], contains descriptions of solids flow modeling; however, it should be noted that there may be more modern and improved models available in the industry.

It can be challenging to collect a solid sample within a facility. Solid sampling should always be considered when maintenance activities within a facility require removal and replacement of piping, as samples can be obtained from the section being removed. Collecting a solid sample from pig traps following a pigging run is another option. Additionally, tank bottom samples can be collected during out-of-service inspections. Unfortunately, with pigging and tank bottom samples, it can be challenging to differentiate between solids that may be present within different piping segments within the same facility. However, samples collected from a pig trap or tank bottom may be more useful in comparing solids that could be present at one facility versus another.

NACE Publication 61114, *Underdeposit Corrosion (UDC) Testing and Mitigation Methods in the Oil and Gas Industry* [10], provides an overview of various test methods that can be used to evaluate corrosion occurring under sand, scale, and corrosion products, such as iron carbonate and iron sulfide. If the composition of solids present in a facility is known, testing using the methods described in NACE Publication 61114 could be used to better understand the potential for corrosion to be occur. Testing of UDC associated with waxes, asphaltenes, and biofilms is not included in that publication.

Frequently, failures within liquid systems are attributed to a combination of UDC and MIC because the deposits enable bacteria growth. It could be that the deposits provide a food source for bacteria, provide a location for the bacteria to attach to the pipe surface, or that the deposits protect the bacteria from the remaining environment.

3.3 Microbiologically Influenced Corrosion (MIC)

MIC occurs due to the metabolic activity of microorganisms in surface attached communities called biofilms. MIC is commonly considered to be the most prevalent internal corrosion mechanism within liquid systems, particularly within facility piping. The low-flow and no-flow conditions (i.e., dead legs) that can be common within facilities, in addition to the intermittent nature of the operation of some lines (such as tank lines) and the inability to perform maintenance pigging on most sections to remove deposits from the pipe interior surface, create an environment that has a higher potential for MIC to occur in facility piping when compared with transmission pipelines. Additionally, applying a chemical as a mitigation measure (i.e., biocide) is more challenging within a facility for the same reasons—there is a lack of flow and pigging to push the chemical throughout the line and ensure that it is reaching the entire pipeline surface by disrupting or displacing deposits on the pipeline surface.

The presence or abundance of microorganisms does not necessarily mean that MIC is an active corrosion mechanism. It is important to characterize and integrate information about the microbial community, chemical environment, design and operation, and materials and corrosion products to appropriately diagnose, mitigate, and monitor MIC. There are several methods that can be used to characterize the microbial community, and the type of information obtained (microbial activity, microbial diversity, and microbial abundance) from these methods depends on the method selected.

Culture-based methods (such as serial dilution bottles) are commonly used to detect and enumerate specific microbial groups, such as sulfate-reducing bacteria (SRB) and acid-producing bacteria (APB). Because nutrient media specific to these microbial groups are used, false positives and false negatives are common with culture-based tests. Further, culture-based tests cannot be used for other MIC-causing groups, such as methanogens, sulfur oxidizing bacteria, or iron reducing bacteria. NACE Standard Test Method TM0194, *Field Monitoring of Bacterial Growth in Oil Field Systems* [11], discusses serial dilution testing. Enzyme-based methods such as adenosine triphosphate (ATP) assays are used to obtain information on microbial activity in a sample. Only microorganisms that are metabolically active can participate in corrosion reactions and cause MIC. ATP assays do not provide information on the microbial group present. DNA-based methods such as quantitative polymerase chain reaction (qPCR) and DNA sequencing provide reliable information on the microbial community. qPCR can be used to obtain information on microbial abundance and diversity by targeting bacteria, archaea, and specific MIC-causing microbial groups, such as sulfate-reducing bacteria, sulfate-reducing archaea, methanogens, fermenters, acetogens, iron-reducing bacteria, iron-reducing archaea, sulfur oxidizing bacteria, or iron oxidizing bacteria. DNA sequencing can be used to obtain untargeted microbial diversity. NACE/AMPP TM0212–2018, *Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion on Internal Surfaces of Pipelines* [12], discusses various methods for microbiological testing of internal surfaces of pipelines. AMPP TM21465–2024, *Molecular Microbiological Methods—Sample Handling and Laboratory Processing* [13], contains procedures for sample collection, processing, and laboratory analysis specific to DNA-based methods.

If MIC is identified as a threat, appropriate mitigation methods should be selected, applied, and monitored for effectiveness. Multiple lines of evidence should be used to select the appropriate mitigation method and to monitor the effectiveness of the applied mitigation. The effectiveness of MIC control should incorporate corrosion monitoring and not rely solely on microorganism population monitoring. Microorganism population numbers do not necessarily indicate how corrosive the environment is, and any effective mitigation method must reduce corrosion rates to acceptable levels. Microorganism population monitoring should include evaluating the impacts of mitigation methods on biofilms and not just planktonic populations. At the time of this publication, there are efforts in progress at AMPP to develop a document for laboratory evaluation of the effect of biocide on microorganisms.

3.4 Other Corrosion Mechanisms

Although UDC and MIC are expected to be the likeliest corrosion mechanisms for liquids facility pipelines and piping, depending on the pipeline environment, other corrosion mechanisms may be present.

3.4.1 Dissolved Gases

Carbon dioxide, hydrogen sulfide, and oxygen are all corrosive species in the presence of water.

Carbon dioxide (CO_2) creates a weak acid in water and can be associated with general corrosion, localized corrosion, or flow-induced attack. Similarly, hydrogen sulfide creates a weak acid in water, and also can create a sulfide scale, which can be cathodic to steel. H_2S corrosion is also associated with UDC and environmentally assisted cracking (EAC).

3.4.2 Oxygen Corrosion

Oxygen can result in high corrosion rates in even minor concentrations in the presence of an electrolyte. Oxygen is typically only present in systems as a result of ingress; therefore, if oxygen corrosion is occurring, the source should be investigated and remediated.

3.4.3 Stress Corrosion Cracking

Stress corrosion cracking (SCC) is a form of EAC associated with fine cracks that penetrate into the pipeline material. These cracks are the result of very specific corrosive environments interacting with specific alloys and tensile stresses on the pipeline. In addition to SCC as an integrity threat at hazardous liquids pipeline facilities, SCC has also been observed in methanol and ethanol systems.

3.4.4 Stress-oriented Hydrogen Induced Cracking

Stress-oriented hydrogen induced cracking (SOHIC) is a type of hydrogen induced cracking that is associated with through-wall cracks due to the diffusion of hydrogen into the metal. SOHIC is most typically associated with low-strength steels adjacent to areas of higher hardness (i.e., welds). Wet environments containing H_2S are needed for SOHIC to occur.

3.4.5 Elemental Sulfur

Elemental sulfur can be formed by the oxidation of hydrogen sulfide due to oxygen entry into the system. This chemical reaction produces both elemental sulfur and water, and can result in high corrosion rates within the system.

3.5 Operational Factors

Operational factors that influence internal corrosion within facilities include intermittent flow, the need for relief lines and bypass segments, shut-ins, start-ups, and inability to use cleaning pigs.

The intermittent nature of flow within some portions of facilities increases the potential for internal corrosion to occur. There may be particular storage tanks (or entire facilities) that are not used on a regular basis depending on product and system demand. Additionally, in larger tank manifolds, dead legs can be created depending on which tanks are in use. Maintaining a general understanding of which portions within a facility are used least often can be helpful in identifying lines and manifolds that may be most susceptible to internal corrosion. Additionally, tracking when lines are in operation can be used to make decisions to help minimize periods of no flow for given segments within a facility, and suspending service of incoming or outgoing pipelines could cause an entire facility to experience no flow for a period of time.

Bypass lines are common around valves or equipment such as pumps and separators so that an alternative flow path exists in the event that it is unnecessary or undesired to route the flow through the equipment (e.g., during equipment maintenance). Bypass lines cannot generally be removed from facility designs. Similarly, relief valves are a necessity of operation. However, both serve as “operational dead legs” (i.e., there is an ability to flow through the segment; however, the way it is operated results in an environment similar to a dead leg).

There are several other operational activities that may impact corrosion potential. Oxygen ingress may occur during various operation activities, such as opening and closing valves. Adding tie-ins to production lines could change the fluid corrosivity. Additionally, operations may require abruptly changing flow direction. In these cases, erosion should be considered as a possible corrosion mechanism.

3.6 Facility Design Impacting Internal Corrosion

Facility piping can be categorized as multiple line types: relief lines, manifold transfer or crossover lines, headers, bypass lines, and tank lines. Additionally, there are non-pressurized systems, such as drain lines.

3.6.1 Dead Legs, Low-flow Pipe, and Intermittently Used Lines

Dead legs, low-flow pipe, and intermittently used lines—examples of which include relief lines, stubs, and bypasses—are all locations where internal corrosion is more prevalent because of the corrosion factors previously identified. Relief lines and other segments that are intermittently used for their intended design/purpose are often referred to as “operational dead legs.”

Industry experience has shown that many dead legs within facilities were created by facility overdesign. At the time many facilities were built, accommodations were made for future expansion. An example includes dead legs off of headers that were intended to lead to additional pumps, manifolds, separators, meters, or tanks in the future that were never installed. Also, while not necessarily an overdesign, redundant meter runs may not be used for long periods.

Sometimes, dead legs are created after a facility is in operation when, for example, equipment is removed but the associated piping is simply capped or blind flanged, leaving a dead leg in place.

Facility drawings, such as isometrics and piping drawings, can be used to identify the locations of dead legs. Piping and instrumentation diagrams (P&IDs) can also be used; however, information regarding dead leg or branch connection orientation would not typically be discernable on a P&ID (i.e., it is not possible to tell if a branch is connected to the side, top, or bottom). Additionally, identification of dead legs via drawings requires that the drawings are up-to-date and accurate. Field reviews of facilities in conjunction with drawing reviews could be helpful in identifying dead legs, particularly of above-grade piping.

3.6.2 Low Spots

Industry incident statistics show that internal corrosion is more prevalent at low points in facility piping than other locations, as these locations are where water and solids can accumulate. Finding localized low spots within relatively flat sections of pipe in a facility can be difficult. However, there are other low spots that are easy to identify because they are associated with offsets to go under or over other piping within the facility or to go underground after connecting to an existing tank or other equipment. Again, facility drawing reviews in conjunction with field reviews can be helpful in identifying low spots.

3.6.3 Inclines

Similar to low spots in the facility, areas of incline can be locations of water drop-out that allow accelerated internal corrosion to occur. These areas of incline are not discernable on a P&ID, so it is more imperative to conduct field reviews of facilities to identify these inclines within the facility.

3.6.4 Oversized Piping

As discussed previously, related to API Pipeline Strategic Data Tracking System (PSDTS, successor to PPTS) data, pipe diameter is a factor related to the potential for internal corrosion. For larger-diameter pipe, an increased flow rate is needed to entrain or sweep water and solids. When facility piping is oversized, typically for future capacity or other design considerations as discussed above (see 3.6.1), there is a higher potential for internal corrosion to occur, and simultaneously the piping becomes more difficult to mitigate (e.g., higher flow required in a larger pipeline for adequate sweeping).

3.6.5 Drain Lines

Drain lines within facilities are used for several purposes, such as those associated with tanks and separators that are designed to remove water that has separated from hydrocarbon product. Some drain lines are not pressurized and are isolated from the pressure vessel by a control valve that only opens when the water reaches a certain level. The flow rates associated with pressurized lines are generally greater than non-pressurized lines, and residual water and solids are “pushed” through the line; however, corrosion rates within pressurized lines can be higher due to higher partial pressures of dissolved gases.

Because drain lines are exposed predominantly to water, they do not receive the benefit of hydrocarbon surface wetting, which other pipe segments within a facility benefit from and which provides some protection for internal corrosion to develop. Additionally, depending on the design of the drain system, oxygen ingress is a possibility, which increases the corrosion potential. Most non-pressurized drain lines are designed to flow based on gravity (i.e., a slight downward slope).

3.6.6 Bends

For small-diameter piping and other piping experiencing high-flow velocities, bends, and other locations where flow direction is abruptly changed, there is an increased potential for erosion to occur.

3.6.7 Inaccessible for Inspection

Facility piping is often challenging to inspect for internal corrosion because the piping is buried and not capable of being inspected using in-line inspection (ILI) tools. When inspections are performed, locations frequently need to be prioritized (i.e., not all piping is able to be inspected); inspections generally focus on low elevation points and low-flow piping. Inspection methods include excavation and inspection of sections of pipe using various technologies, including guided wave and standard ultrasonic techniques to measure pipe wall thickness, and using internal corrosion direct assessment (ICDA) following NACE SP0208–2008 [9]. Having piping above grade allows for easier inspection and eliminates the potential for issues that could occur due to excavation. Additional discussion on inspection methods is provided in Section 4.

4 Prevention, Control, and Remediation

The following sections describe various options that may be used to prevent, control, remediate/mitigate, and, when necessary, repair piping segments to address internal corrosion within facilities. There is not one universal option that will work on all types of lines at all facilities.

4.1 Minimizing/Eliminating Dead Legs

Management options for addressing dead legs are limited and consist of either removing the dead leg to remove the potential for development of internal corrosion and subsequent failure, or making operation or facility design changes to minimize internal corrosion as an integrity threat. Operational and design changes/modifications at existing facilities should be based on the unique considerations at each liquids pipeline facility. For newly constructed facilities, the design parameters should consider avoiding dead legs and minimizing sections of piping that will only operate intermittently. An additional design factor to consider is including injection points for biocides and including access points for the use of internal inspection and cleaning tools.

As discussed in Section 3, certain facilities may have intermittent operational dead legs by design. These lines can be addressed through operational procedure adjustments or scheduled line sweeping/flushing as a mitigation technique.

4.2 Line Sweeping (Flushing)

Because most facility piping is unpiggable, line sweeping (also referred to as “flushing”) can be one of the few mitigation options. For line sweeping, the desired flow velocity should be determined to assess if that velocity is feasible to achieve. Flow models consider the velocity needed to keep solids and/or water entrained or flowing. Calculating the velocity to re-entrain or move solid deposits is not as straightforward, but it can be assumed that the same or greater velocity is required for sweeping than is required to keep solids entrained/flowing in a continuously flowing system. Additionally, there are currently no industry documents that provide guidance as a basis for a sufficient time to flow or at what frequency. Because it may be more difficult to remove solids the longer they have been in place, it is reasonable to perform sweeping for longer periods of time and at higher velocities on the segments that have not experienced flow for longer periods of time than those that have been non-operational for a shorter period of time. However, the duration of line sweeping is more likely to be governed by what is feasible based on the source of flow and how flow is being achieved (i.e., determining if a valve being opened to allow flow in an operational dead leg or is sweeping/flushing being performed into a tank or other vessel). Additionally, depending on branch configuration/orientation, it is possible that more solids may be pushed into dead legs that are swept less frequently.

Regarding sweeping frequency, a PPTS operator advisory from 2009 concluded that having flow annually was not sufficient to prevent internal corrosion failures from occurring; however, the advisory did not comment on what might be an acceptable flow or sweeping frequency [14]. Pipeline operators should consider developing a sweeping/flushing program for infrequently operated and non-operational lines that is based on the specific facility configuration and operations.

4.3 Chemical Cleaning and "Mothballing"

For situations where solid deposits are impacting internal corrosion via UDC or MIC, chemical cleaning could be used to remove accumulated deposits. Solvents can remove organic and inorganic deposits; however, it is necessary to understand the composition of the solids to select the most effective chemical for cleaning. For example, hydrocarbon solvents such as toluene, xylene, and terpenes could be used to remove asphaltenes and paraffins, but other chemicals such as acids or chelating agents may be required to remove corrosion deposits or scales [15] [16]. The ability to remove the cleaning chemical needs to be considered any time that chemicals are used. Many cleaning chemicals can have corrosive properties, so if they are not properly removed from the piping, additional internal corrosion can occur. One means of chemical cleaning could be to drain a line while it is out of service, then insert and remove the chemicals via a tap or flange fitting.

There are some design situations where the dead leg can be "mothballed." These situations are more likely to exist when a dead leg can be isolated by a valve, such as a bypass. In those instances, it may be possible to chemically clean the segment and then fill it with a product with a low potential for internal corrosion. "Mothballing" is likely not a good option for operational dead legs that are used on an occasional/infrequent basis, as the mothballing would need to be re-established any time the dead legs saw flow.

4.4 Mechanical Cleaning

There are also mechanical cleaning options within facilities. While maintenance pigging is generally not considered feasible for facility piping, it could be possible to use a crawler tool equipped with brushes or disks or a tethered tool. In either instance, a temporary insertion device may need to be used, and similar to chemical cleaning, determination needs to be made for where the water/debris will be pushed or how it will be removed. An alternative means of mechanical cleaning is hydro jetting; however, the piping to be cleaned would need to be taken out of service for this to be performed. At present, hydro jetting is not a commonly used technique within pipeline facilities and could leave residual water in the pipe.

4.5 Chemical Treatment

Chemical treatment—corrosion inhibitor and/or biocide—can be used to minimize internal corrosion within facilities. While chemical treatment is usually performed either continuously or in batch treatment in conjunction with pigging on mainline and stub-line segments, neither of these options are typically available for facilities piping that does not continuously see flow and is not piggable. Batch treatment within facilities either injects chemicals when the piping is flowing or, if injected under stagnant conditions, relies on the inhibitor to settle to the same locations in which water and solids accumulate. One of the challenges of chemically treating piping within facilities without pigging is that there is no mechanical means to disrupt any solids that may be present to allow the chemical to reach the pipe area. Frequently, this is attempted by including dispersants within the chemical mixture. It is particularly important for biocides to reach the microorganisms affecting corrosion. Otherwise, it is possible for a biocide to kill planktonic bacteria and even sessile bacteria on the outermost surface of a biofilm, while still allowing MIC to take place unmitigated at the pipe surface. Additionally, biocides and inhibitors will adsorb to the solids, making less chemical available to reach the locations where it is needed.

4.6 Water Removal

If water is not present in the system, internal corrosion cannot occur. Therefore, water separation and oil dehydration equipment can be an effective way of preventing internal corrosion. Depending on their efficacy, these methodologies may need to be used in conjunction with others (e.g., pigging, chemical inhibition) to provide corrosion control.

4.7 Coatings/Lining

Internal coatings can be an effective way of preventing internal corrosion in a facility by forming a barrier between the corrosive environment and the pipe/vessel/component wall. These internal coatings must be evaluated for their suitability for the pipeline service prior to their use, and these coatings must be applied correctly. For example, the case study in NACE International Paper No. 00009, *Report of a Coating Failure on a 16-in. Oil Pipeline Under Wet CO_2 Service* [17], shows what can happen if a coating is improperly applied. Improperly coated pipe can allow localized corrosion in locations of coating disbondment or removal. Typically, internal coatings are applied at the time of construction. If weld joints are not coated, these areas remain susceptible to internal corrosion. Linings can be installed at the time of construction or in piping that is already in service. Of note, most internal inspection techniques cannot be used for piping with coatings or linings installed; however, this is generally not a concern within facilities based on the challenges associated with using internal inspection tools.

5 Inspection

Typical internal corrosion inspection methods for facility piping include external inspection tools, internal inspection tools, and visual inspection.

5.1 Inspection Methods

5.1.1 External Inspection Tools

External inspection tools to assess internal corrosion include manual ultrasonic thickness (UT), automated ultrasonic thickness (AUT), and radiographic testing (RT). Manual UT, AUT, and RT provide information regarding the condition of the pipe at the specific location where the inspection occurs. Therefore, selection of the locations where the inspection is to be performed is important to ensure meaningful data are collected.

AUT inspections offer many advantages over manual UT measurements when inspecting facility pipe for internal corrosion. AUT can take thousands of measurements in a short amount of time, can interpret the results rapidly, and enables better visualization and documentation of data. Some disadvantages of using AUT over manual UT include a larger initial investment and the possibility of incorrect calibration affecting data accuracy.

Other external inspection tools include magnetic flux leakage (MFL) tool that attaches externally to the pipe. This inspection technique allows fast and efficient scanning of large volumes of exposed pipe, requires no couplant, and requires minimal surface preparation.

5.1.2 External Indirect Inspection Tools

External indirect inspection tools include guided wave ultrasonic thickness (GWUT) technology, which is capable of inspecting longer sections of pipe from a single location depending on the pipe and coating characteristics. Two different types of GWUT are long-range ultrasonic thickness (LRUT) and short-range ultrasonic thickness (SRUT). Both methods use low-frequency sound waves to measure flaws in a large volume of material from a single test point. LRUT uses a ring of transducers fixed around the pipe that provide 100 % coverage of the pipe wall for the inspection distance. The maximum inspection distance is dependent upon pipe properties, coating, fittings, and soil properties for buried pipe. SRUT utilizes a single transducer for a much shorter range. SRUT is primarily used for inspecting short spans of pipe under insulation, corrosion under pipe supports, tank floors, and tank shells.

5.1.3 Large Standoff Magnetometry

Large standoff magnetometry (LSM) is an emerging non-intrusive screening method that detects changes in the magnetic field of a pipeline to determine if material defects are present. LSM can detect when the pipeline wall is undergoing stress, including defects from corrosion, dents, or other abnormalities. The effectiveness and accuracy of LSM is still being evaluated.

5.1.4 Internal Inspection Tools

Facilities are typically not designed to allow for internal piping inspection. The majority of piping within facilities does not have launchers or receivers to accommodate traditional in-line inspection tools or cleaning pigs. Facilities are usually built with standard fittings, such as short-radius elbows, making inline inspection tool passage difficult. Dead legs, low-flow piping, and intermittent flow piping also make it difficult for inline inspection tools to traverse pipe. It may be feasible to make longer segments of pipe piggable, especially if it is necessary to determine the condition of the entire line (e.g. tank lines). Temporary launchers and receivers may be used if space is an issue.

If making a segment of facility pipe piggable is not feasible, tethered ILI tools may be an option for internal inspection. Tethered ILI tools require that the line be blown down with inert gas and pulled through the pipe segment. The advantage of tethered tools is that the only requirement is an insertion point, although they are most feasible if the pipe segment is out of service/drained of contents. Tethered tools may be inserted at a flanged location, or the pipe may be cut. Limitations include the number of bends the tethered tool can pass through and the required cleanliness of the pipe, depending on the specific inspection technology.

Robotic crawlers are another option to inspect unpiggable pipe. The advantage of robotic crawlers over tethered tools is that the line being inspected does not need to be blown down with compressed gas because they are self-propelled. However, robotic crawlers can be limited in application as they have problems navigating bends.

Electromagnetic acoustic transducer (EMAT) ILI tools can be used for inspecting facility piping when it is challenging to clean the pipe. EMAT tools are traditionally used for stress corrosion cracking (SCC) detection and coating disbondment detection. However, EMAT can also be used to inspect difficult-to-clean lines for internal corrosion because EMAT is a non-contact tool that does not require a liquid couplant. Consideration should be given to how the cleanliness of the line will affect data accuracy.

5.1.5 Internal Visual Inspections

Visual inspections should be performed any time the internal surface of the pipe is exposed. Pipe exposure could be a result of replacing a section of pipe or removing a flange face for some reason. Hot tap coupons also serve as a means to obtain visual inspection information, but they are very limited. It is typically not feasible to perform visual inspection as a scheduled inspection (versus opportunistic); however, borescopes could be used when a pipe segment is out of service to attempt to gain some information. The pipe segment would need to be de-inventoried and the surface cleaned to some degree to perform a borescope inspection.

5.2 Inspection Program

5.2.1 Buried Pipe

For buried pipe at a facility, a dig program similar to ICDA for mainline pipe can be used to target facility piping that is most susceptible to internal corrosion. Factors to consider for internal corrosion susceptibility of facility piping include corrosion rates from electrical resistance (ER) probes and/or coupons (as available), product quality, incident and release history, piping elevation for low spots, or operational factors. Piping elevation data can be gathered from GPS and depth-of-cover surveys or engineering drawings such as piping mechanical drawings, piping plan drawings, piping isometrics drawings, plot plans, process flow diagrams, or P&IDs. Operational factors contributing to internal corrosion can be determined by reviewing the engineering drawings, studying supervisory control and data acquisition (SCADA) data, interviewing operations personnel, and visually inspecting the facility. Indirect external inspection methods such as GWUT can be used to screen facility piping for internal corrosion and aid in determining internal corrosion susceptibility. Once internal corrosion susceptibility is determined, an appropriate sample of buried piping segments can be excavated and inspected using a direct external inspection method such as AUT.

5.2.2 Aboveground Pipe

For aboveground pipe at a facility, an API 570 [18] inspection program can be implemented to address internal corrosion. Alternatively, externally attached inspection technologies such as AUT can be used to inspect above-ground pipe, or above-ground pipe can be screened for internal corrosion features using an indirect method such as GWUT.

6 Monitoring

6.1 Permanently Mounted External Non-intrusive Monitoring Tools

For long-term internal corrosion monitoring, UT collars and GWUT collars can be mounted to the exterior of the pipe to provide real-time UT and GWUT readings. UT collars permanently mount several ultrasonic transducers around the circumference of the pipe, giving the user multiple thickness readings. The exact number of transducers that can fit on a collar depends on the outside diameter of the pipe. Both UT and GWUT collars can be used in tandem, can be buried below ground, and are useful for monitoring corrosion at susceptible locations.

6.2 Intrusive Monitoring

Coupons and probes can be inserted directly into the pipeline to monitor the corrosion rate within the pipe environment.

Coupons are exposed to the internal pipeline environment for a period of time, often three to six months, and are removed to undergo laboratory analysis. This analysis includes cleaning and weighing the coupon to determine a corrosion rate, and often the deepest pit is measured as well to determine a pitting rate. If coupons are manufactured to a fine enough grit, they can be viewed under a scanning electron microscope (SEM) to determine pit initiation (biotic vs. abiotic). Coupons can also be swabbed in the field for microbiological analyses.

Similar to coupons, ER and linear polarization resistance (LPR) probes are composed of the same material as the pipeline. LPR probes require continuous submergence in an electrolyte to function properly and obtain meaningful results, so are limited to water lines or systems with high water cut. Probes can be prone to fouling by oil, paraffin, iron sulfide, and scale. However, if used in the right location, probes can provide continuous, remote corrosion rate monitoring. These can be useful for the detection of process upsets or other short-term corrosive conditions. ER and LPR probes cannot be used to determine a pitting rate.

In the cases of both coupons and probes, although these are intrusive techniques, flush-mount options exist for locations where pigging may occur.

NACE 3T199–2012 [19] provides additional details regarding various monitoring techniques.

7 Case Studies

The following case studies are provided to show the variety of approaches that operators are using to address the threat of internal corrosion across their facilities.

7.1 Case Study 1

Operator 1 was proactively investigating facility piping for internal corrosion. The principles of liquid petroleum ICDA were applied to identify locations along facility tank piping and manifolds for external UT inspection. Data regarding the history of operation and typical flow rates were collected and used along with global positioning system (GPS) information regarding the elevation profiles of the piping to identify and prioritize locations for inspection. Typical of ICDA detailed examinations, bell-hole inspections were performed at selected locations where coating was removed and UT inspection was performed. Inspections showed varying results; at some locations minimal to no internal corrosion was identified, while at other locations, more severe corrosion was found. During one of the inspections, a leak was discovered in the area immediately adjacent to where coating was being removed. Investigation into the leak identified that while the location selection was intended to be at the low spot, the actual low spot on the line was slightly adjacent to the identified area. This led to increased emphasis on the survey technique and interval for determining elevation profiles, as the majority of the piping was in relatively flat facilities where low points were more challenging to locate. After performing inspections at several facilities, internal corrosion has been more broadly incorporated into Operator 1's overall facility integrity program, where facilities are ranked by risk and inspections are performed to address various threats.

7.2 Case Study 2

Operator 2 had experienced internal corrosion failures at multiple different facilities in dead leg and low-flow piping. The failures were reviewed to determine if common threat mechanisms and operating conditions existed at the locations where failures had occurred. While the failures occurred on a variety of different types of piping, MIC was identified as the likely cause of all failures. Additionally, solids were identified as contributing to the majority of the failures. The data elements relative to the threat of internal corrosion that are typically available for Operator 2's facility piping were reviewed to:

1) determine what data could reasonably be incorporated into an internal corrosion threat model;

2) determine what mitigation methods might be practical to implement; and

3) understand what additional data collection activities might be required to improve the threat assessment process and prevent failures.

Solids flow modeling was performed to estimate the minimum superficial velocity necessary to keep a solid particle suspended within a liquid stream or drag it along the pipe surface. The following inputs were used for the model:

— typical properties for crude oil transported by Operator 2;

— piping diameters present across the various facilities;

— solids information from solid samples.

Operator 2 used the reviewed data to improve their internal corrosion threat model and develop guidelines for determining appropriate mitigation options for various facility piping scenarios.

7.3 Case Study 3

Operator 3 experienced an internal corrosion leak in the low point within the facility piping. The cause of the leak was investigated and, subsequent to the investigation, ultrasonic thickness inspections were performed in above-grade and below-grade portions of the facility, along with robotic visual and EMAT inspections. The entire facility was hydrostatically pressure tested and batch treatments of piping were performed with a corrosion inhibitor and biocide. Some tank lines were reconfigured to be made piggable. "Non-operational" dead legs were removed. Additionally, Operator 3 addresses internal corrosion within a robust Facilities Integrity Management Program (FIMP) that performs integrity testing at intervals based on API 570 [18], considering the product type.

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