CORROSION FAILURE IN A LINED SOUR GAS PIPELINE - PART 1: CASE HISTORY OF INCIDENT

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ABSTRACT

A failure due to internal corrosion occurred on a lined sour gas pipeline. The pipeline was a steel pipeline installed initially with a polyamide liner in 2001 and then re-lined in 2003 with a high density polyethylene (HDPE) liner. Neither of the liners had breached in service, yet corrosion behind the liner occurred and led to failure of the pipeline. The cause of the failure and the strategy to manage corrosion behind the liner in a lined pipeline is discussed. The strategy involved the development of an attributes model, the use of a new inline inspection tool along with changes to the operating and integrity reference plans of the lined sour gas pipelines.

Keywords: sour, failure, pipeline, liner, corrosion, CO2, H_2S, methanol, polyamide, HDPE

INTRODUCTION

In November 2007 Shell Canada Energy (Shell) experienced a sour gas release on the Waterton Screwdriver Creek Pipeline (the SC pipeline).

The SC pipeline is a 2.6km long x 168.3mm OD (NPS 6) x 5.6mm WT sour gas pipeline. The SC pipeline is licensed to a maximum operating pressure of 12,400 kPag and a maximum H2S concentration of 32%. The pipeline was carrying natural gas containing approximately 21 per cent H2S and operating at a pressure of approximately 4300 kPa at the time of the incident. The operating temperature at the SC pipeline inlet, with a well site heater, ran at approximately 45C.

The SC pipeline was installed in November 2001 as a new steel pipeline with a polyamide liner. The SC pipeline transported sour gas from the well to a junction where it tied in with other sour gas pipelines as part of the Castle River gathering system. Sour gas first flowed into the SC pipeline from the well in early 2003. A third party gas well was also tied into the SC pipeline in mid-2003.

Subsequent to polyamide liner collapse and breaches in other polyamide lined pipelines in the neighboring Carbondale gathering system (1,2), the polyamide liner in the SC Pipeline was removed and replaced with an externally grooved HDPE liner. The re-lined SC pipeline was put back into service in December 2003. Sour gas from both wells flowed into the SC Pipeline until the November 2007 failure, just under four years of service time.

BACKGROUND ON LINER USE

Liners have been used in oilfield pipeline applications in Alberta since the mid-70's with the initial use dominated by rejuvenation of produced water injection system pipelines. HDPE liners offered a barrier to corrosive produced water while the outer steel pipeline provided the strength for the pressure containment.

Beginning in the late 1980s HDPE liners were increasingly being used in the rejuvenation of high water-cut oil well production pipelines that were suffering from internal corrosion. A few applications were used in sour gas pipelines that had corrosive fluid properties.

Previous company liner installations included two liners in wet sour gas pipelines in the 1990s, one in the South Waterton field and one in the Jumping Pound field. Both were installed as liners in existing steel pipelines to manage the internal corrosion threats. These two liners were traditional HDPE liners that were externally smooth. Both lined pipelines operated successfully for a number of years (3).

In the North Waterton fields, lined pipelines were first installed in 2000 into existing steel pipelines that had experienced internal corrosion damage. The initial liners used here were polyamide, which was capable of higher operating temperatures than HDPE. The success led to the installation of additional liners in new pipelines being installed in the area.

In 2002, the Carbondale NPS 6 polyamide liner was found to have breached in several locations. The Castle River NPS 8 polyamide liner was also found to have breached. Internal corrosion was found in the Carbondale pipeline. The corrosion was caused by brine and elemental sulphur coming into contact with the steel pipe due to the liner breach. As a result of these breaches, polyamide liners were removed and replaced with the thicker walled, externally grooved HDPE liners in Carbondale and Castle River pipelines.

None of the polyamide liner breaches resulted in a pipeline leak, due to the steel pipe integrity. The cause of the polyamide liner breaches was determined to be a result of:

1. The main failure mechanism was longitudinal buckling (inversion) of the liners. The key factor was ineffective venting of the annulus especially over large line pressure fluctuations. Other factors such as loose fit, thin wall design and chemical additives such as methanol and Dimethyl Disulfide (DMDS) accelerated the failures but were not considered to be the dominant factors.
2. A second failure mechanism involved long duration shut-ins. This failure mechanism involved tensile overload of the liner due to production fluids and additives stripping extractables (plasticizer and oligomer) from the polyamide liner material. Components of the production fluids/additives replace these extractables during normal operations, but when shut-in and/or depressured for an extended period, the production fluids/additives vaporize leading to shrinkage and subsequent tensile overload of the liner.

At the time that the polyamide liners were replaced in the Carbondale and Castle River pipelines, a few short, single segment polyamide lined pipelines in the North Waterton Field were confirmed to be intact and continued successful operation. These short pipelines were found to not have any evidence of liner collapse. It was confirmed that these liners were not exposed to the detrimental additives which stripped extractables from the liner and that would affect the properties of the liner, which also explains why these liners did not experience a tensile overload failure during long duration shut downs.

After removal of the polyamide liner and prior to installing the HDPE liner, the SC Pipeline was inspected visually at the ends of each flanged segment, by evaluation of two cut outs and with a tethered inspection tool in selected locations. Eight selected pipeline locations along the SC Pipeline, including the subject failed portion, each about 80m in length (the capability of the tethered inspection tool at that time), were inspected. The visual inspections did not identify any significant corrosion and the tethered inspection tool did not indicate the presence of any internal corrosion that exceeded the minimum detection limit of the electronic tool. The HDPE liner was installed and the pipeline resumed operation in December 2003. The SC pipeline remained in service until the pipeline failure occurred in November 2007.

FAILURE ANALYSIS

The pipeline failure was the result of an axial split in the steel pipe about 300mm in length with a maximum width of 60mm at centre. The failure occurred 27m downstream of Vent 6 as shown in the elevation profile (Figure 3). It was the result of tensile overload of the steel pipe in a localized area where internal corrosion had removed almost 90 per cent of the pipe wall (Figure 1 and 2).

There was no evidence of a breach in the liner prior to the failure of the steel portion of the pipeline.

In lined (thermoplastic liners) sour gas pipelines, it is known that sour gas permeates the liner. The design premise is for a protective iron sulphide scale to form on the steel pipe since no chlorides or elemental sulphur will permeate the liner. If intact, this scale can provide the steel with effective corrosion protection.

In this case, it appears that the protective iron sulphide scale had not existed in a uniform manner, and as a result corrosion was able to occur in localized patches. In those locations, a paste-like mixture of iron sulphide corrosion product suspended in an acidic liquid, was found sandwiched in the annulus between the HDPE liner and the steel pipe (like the example shown in Figure 4). The liquid component was believed to be primarily methanol, which is used in the pipeline for a variety of purposes, including hydrate control. Methanol was continuously injected into the production fluids to prevent hydrates and also was used occasionally to flush parts of the annulus vent system of the pipeline, thus establishing its presence in the liner annulus. There was no evidence that chlorides, bacteria, or elemental sulphur played a role in the corrosion process.

Further investigation identified the following major factors that contributed to the failure:

- Discrete patches of non-protective scale associated with minor corrosion that had occurred when the pipeline was operated with a polyamide liner, remained when the HDPE liner was installed. These discrete patches of non-protective scale rendered the batch inhibitor ineffective at those locations and also prevented the formation of protective scale, thus allowing localized corrosion to occur.

- Corrodents present in the annulus from a number of sources did not allow the formation of protective scales to occur and further promoted and provided the conditions for ongoing corrosion. Methanol and water (the main corrodents), present at high concentrations and under the right conditions in the annulus, promoted corrosion.

- The non-protective scale, together with liquid and solid debris, partially blocked the annulus vent system, creating poor annulus communication and high annulus pressure that, with the presence of the corrodents, created a more acidic and corrosive low pH environment. These conditions exacerbated the corrosion.

- There was insufficient flow/velocity in the annulus vent system to effectively sweep liquids (and solids) from the annulus. The complex flow path and low-flow conditions, especially adjacent to the bellholes, created liquid traps preventing the liquids and solids from being swept from the annulus.

Other minor factors that may have contributed to the failure were identified as follows:

- Prior to installing the HDPE liner, the SC pipeline was not water flushed in connection with a hydrotest or inspection tool run. This could have helped remove or dilute Debris and/or Corrodents.
- Formic acid, used for well stimulation, might have also permeated the liner as a vapor and further contributed to the low pH condition in the pipeline annulus. However, this is not believed to have played a significant role in the failure.

ACTION PLAN

A five-step action plan was developed to further investigate the scenarios that were identified as possible causes of the incident and to develop a plan to ensure the safe start-up and ongoing integrity of the SC pipeline.

Step 1: Continued Review of Contributing Factors, Conditions, Events—Reviewed factors, conditions, and events that contributed to the incident, with the objective of better understanding the role of the various contributing factors in the incident and the extent to which these factors may be unique to the failure location. This is all with a view to further understanding the conditions that might cause corrosion and how those conditions might occur.

Step 2: Model Development—This involved developing a model to help improve understanding of the failure mechanism and assess the likelihood that similar factors, conditions, and events exist in the remainder of the pipeline and in other lined sour gas pipelines. The model was initially developed based on the information that was available at the time. The model assisted in developing the integrity plan and start-up plan set out in Steps 4 and 5 respectively.

Step 3: Model Validation—This involved developing and executing sufficient inspections, tests, and other methods to validate the model developed in Step 2.

Step 4: Integrity Plan—To confirm the validity of the model, it was necessary to complete certain other activities, that included inspections, tests, sampling, and laboratory testing. It was expected that inspection activities would constitute the majority of activities in this step. Inspections were completed to ensure that the model accurately predicted if and where corrosion can be expected. After the model developed in Step 2 was validated, Step 4 of the Action Plan involved developing and executing a plan to ensure the integrity of the pipeline prior to start-up. The plan may involve inspections, hydrotesting, liner integrity verification, cutouts, and repairs.

Step 5: Start-up Plan—This involved developing and executing a plan to restart the pipeline. The plan included, as necessary, changes to operating envelopes/windows; inspection, mitigation, and monitoring requirements; and operating and maintenance practices.

Steps 1 through 5 were completed and have allowed the successful restart of the majority of the lined pipelines. The SC pipeline had extensive damage and remains out of service.

Investigation

The design premise for the lined pipelines was as follows:

- Liner is a "barrier" to direct contact of the steel carrier pipe ID surface with the corrosive produced fluids
- Liner is "permeable" (by design). Gases can permeate the liner and collect in the liner/steel annulus. Venting of the annulus is required to avoid the case of annulus pressure exceeding the pipeline pressure enough to collapse and fail the liner
- Protective iron sulfide scales form on the steel carrier pipe ID surface resulting in low corrosion rates
- Scale disrupters (e.g. chlorides, elemental sulfur) which can breakdown the protective iron sulfide scales cannot permeate the liner
- Should a failure (breach) of the liner occur, the liner integrity monitoring strategy (annulus pressure monitoring system) would alert operations to the condition in a timely manner for measures to be taken before a loss of containment would occur

Subsequent to the problems encountered with the polyamide liners, efforts were made to find ways to avoid liner collapse. HDPE was chosen as a new liner material for its resistance to damage by methanol and sulphur solvents. The HDPE liners were designed with thicker walls and external grooves in order to prevent liner collapse and allow permeated gases to vent through the annulus vent system. The externally grooved liners were designed with vent tubing across flange connections (1,2). The vented gas flows through a scrubber where the gas is sweetened.

This paper will not go into detail on the corrosion that occurred, since that is covered in the companion paper Corrosion Failure in a Lined Sour Gas Pipeline - Part 2: Role of Methanol in Corrosion Behind Liner (8).

The internal corrosion of the SC pipeline meant that something had disturbed the normally protective iron sulfide scale. Within the industry it is known that certain contaminants can cause iron sulfide scale to become non-protective. The list of contaminants that can disrupt iron sulphide scale includes:

- chlorides
- elemental sulphur
- low pH
- methanol

In bare steel pipelines transporting wet sour gas, the top two contaminants in the list above are the primary internal corrosion drivers that allow the wet-H_2S corrosion to continue without the formation of a protective iron sulfide scale (1,7).

Low pH can lead to dissolution of the iron sulfide scale. Dissolved acid gases, H_2S and CO2, lower the pH and the presence of any acids would further lower the pH of the water.

In 2003, it was believed that the annulus would contain wet sour gas, but the amount of water and methanol would be small. It was believed that wet sour gas in the annulus, without chlorides, elemental sulphur and large amounts of methanol, would cause only a low corrosion rate and protective scale would develop, which would also reduce corrosion rates.

Subsequent to the failure, Shell developed the Process Model, which is a process engineering simulation, to better understand the operation of the HDPE liner and the conditions in the annulus. It is now understood that 90% of the liquid methanol injected into the production at the well site, is vaporized downstream of the well site heater. This creates a relatively high vapor pressure in the production fluids and leads to greater than expected permeation of methanol vapor through the HDPE liner into the annulus.

The Process Model also shows that the gas that permeates through the HDPE liner into the annulus will include small amounts of methanol vapor and water vapor. The permeated annulus gas is below the dew point of water and methanol at all annulus pressures experienced. Therefore, it is now understood that the small quantities of methanol and water vapor that would permeate through the HDPE liner into the annulus would condense and collect within the annulus. Liquid methanol added directly into the annulus would also exist as vapor or liquid within the annulus, depending upon the pressure and temperature in the annulus.

The Process Model also suggests that the liquid condensed in the annulus will be dominated by water and methanol. Initially, the water volume would exceed the methanol volume, but the latter would still be significant. Subsequently, as annulus gas flows through the annulus vent system towards the scrubber (located at the end of the Pipeline), more vapors may condense, as conditions allow. The Process Model shows that the long jumper vent tubing used on the Pipeline at the flange bell holes would lead to condensation, due to greater cooling in this part of the annulus vent system. The Process Model shows that condensed liquids from this gas stream will have more methanol than water in the liquid. Other studies on the behaviour of methanol in unlined sour gas pipelines are consistent with the model results (6).

Inspection of the failed SC pipeline and the other lined pipelines in sour gas service has confirmed that the use of continuous methanol injection was a common attribute (threat) that led to mainly isolated pitting damage in a number of the other lined pipelines. This kind of corrosion is different than the corrosion that caused the failure of the SC pipeline. The SC pipeline was the only pipeline that experienced the larger patches of corrosion damage that resulted in the failure. It was the size and location of these corrosion patches that supported the belief that the corrosion initiated at the failure location during the polyamide liner service.

With findings gained from the investigation, a line-by-line assessment was carried out of all Shell's other lined sour gas pipelines in Alberta, including the shut-in lined pipelines. As the assessments of the pipelines were completed, individual plans were submitted to the regulator in support of the restart of each of the pipelines, along with appropriate measures to help ensure the long-term integrity of each pipeline.

Liner Attributes Model

The attributes model consists of a spreadsheet containing the various factors that were understood that may have contributed to the conditions that caused the failure. Using the failed SC pipeline as the base case, all other lined pipelines within the system were assessed to determine if the same contributing factors might be present. The information contained in the attributes model was then used to flag other lined pipelines that may be expected to have the same conditions that eventually resulted in the failure of the SC pipeline. It should be noted that just having some or all of the same conditions present does not mean that a particular pipeline has corrosion damage like that experienced in the SC pipeline.

Using the information in the attributes model, certain inspections and other activities were planned to assist with validation of the model. The verification activities were designed to:

- confirm if some or all of the contributing factors were present in a specific pipeline or not;
- establish if corrosion damage was present similar to what caused the failure in the SC pipeline; and
- improve the accuracy of the attributes model by updating it, using the information from the above validation activities.

Based on the work completed to date in respect of the attributes model, the following has been concluded:

- Conditions that contributed to the failure were not unique to the area of the SC pipeline that experienced the failure.
- Similar conditions were expected to exist in the remainder of the SC pipeline. This was confirmed by:

- In-line inspections (ILI) using magnetic-flux leakage and electromagnetic type inspection tools completed on the remainder of Segment 6 (the failed segment) and Segment 5 (the segment immediately upstream of Segment 6) where corrosion damage similar to that which existed at the failure site has been found.
- Inspections by radiographic (RT) methods of piping in the flange pair bellholes along the Pipeline indicate corrosion damage and liner liftoff which appear to be similar to the features noted at the failure location.

- The combination of conditions that may have contributed to the failure of the SC pipeline is not present in other lined pipelines. However, some of the conditions that may have contributed to the failure in the SC pipeline are present in other lined pipelines in the system.
- The attributes model indicated that a lined sour gas pipeline in the Burnt Timber Complex had many (but not all) of the same attributes as the SC pipeline and therefore may also be susceptible to similar corrosion damage. This pipeline was inspected to determine if similar corrosion was present. These inspection activities have not identified any large areas of corrosion damage similar to those found on the SC pipeline. One significant reason that corrosion was present in the SC pipeline, but not the Burnt Timber pipeline is likely because of the fact that methanol was not continuously injected into the Burnt Timber pipeline for hydrate control.

The results of our inspection work found only minor corrosion in the inspected pipelines (other than the SC pipeline). The results to date are encouraging and are consistent with the conclusions regarding the major factors that caused the failure of the SC pipeline. The results also provide validation for the attributes model.

Inspection

Work was undertaken with an Alberta based company to modify an existing electromagnetic inline inspection (ILI) tool to be used to determine the integrity of the steel pipeline in a lined pipeline with the liner remaining in place. Field trials demonstrated that the tools are capable of inspecting for corrosion of the steel carrier pipe through the liner and inspection work on the lined sour gas pipelines was completed. This was a new application of the technology and was developed in response to this incident.

Inspections have been completed on the majority of the lined pipelines and to date has not detected any other significant corrosion damage like that which caused the failure in the SC Pipeline. Most of the pipelines were inspected with an ILI tool capable of inspecting the steel pipe integrity with the HDPE liner still in place.

During log verifications and bell hole inspections minor isolated pitting adjacent to the external grooves in the HDPE liner was noted in a number of pipelines. This type of damage has been found in lined pipelines of varying age, ie; from 2 to 7 years and all to similar depths. The depth of such pits was as much as 28% of the pipe wall in one pipeline. This pitting is like the axial pitting shown in Figure 5 which is approximately 30% of the pipe wall and adjacent to the external grooves on the HDPE liner.

The verification dig findings confirmed corrosion activity on recently lined pipelines that had received continuous methanol injection into production fluids for hydrate control. In one segment of HDPE lined pipeline that had less than one year of service, shallow (4%WT) grooving was detected adjacent to the external grooves in the HDPE liner (Figure 6). This suggests that, while different than the corrosion mechanism that caused the SC pipeline failure, corrosion behind HDPE liners in sour gas pipelines can be a threat where methanol is continuously injected into the production fluids. Consideration should be given to taking steps to properly assess and manage the risk of such corrosion.

Changes in Operating Practices and Integrity Reference Plans

With the experience and learnings from this incident changes were implemented to the operating practices and integrity reference plans for lined sour gas pipelines. The main changes are:

- Continuous injection of methanol into production fluids for hydrate control is not allowed.
- If short-term use of methanol is required, the pipeline is pigged afterwards to remove the methanol from the environment.
- The use of methanol is no longer allowed for clearing or de-icing the annulus vent systems without prior assessment and approval.
- Monitoring corrosion rates using on-line corrosion monitoring devices at two selected locations with prior corrosion damage to measure the effectiveness of the above mitigation items.
- Any liquids and/or solids collected from the annulus vent system are sampled for analysis.
- Periodic inspection using ILI and bell hole NDE.

CONCLUSIONS

1. Methanol permeation into the annulus vent system on polyamide and HDPE lined pipelines in wet sour gas service is a credible internal corrosion threat. This threat is magnified in polyamide lined pipelines but is also a threat in HDPE lined pipelines.
2. This internal corrosion threat needs to be understood and managed effectively to avoid internal corrosion damage.
3. The kind of damage seen in the failed pipeline has not been observed in any other operated pipeline inspected to date. Isolated internal corrosion pitting to approximately 25% depth was observed in a number of the lined

pipelines. The common attribute in these pipelines was the continuous use of methanol for hydrate control.

4. The effectiveness of the changes to the operating practices described above in managing corrosion continues to be assessed through enhanced monitoring activities. To date we have seen positive monitoring results since the implementation of the changes to the operating practices.
5. Inspection tools have been developed and used for the inspection of the steel pipe in a lined pipeline without removal of the liner.
6. Permeability of methanol and water through liner materials has been re-evaluated and with this knowledge, it is apparent that the liner annulus may contain 3 phases; sour gas, hydrocarbon liquids and an aqueous phase. The removal of liquids and solids from the annulus vent system can be difficult to achieve and accumulation of solids and liquids in the annulus can occur. Further research on this mechanism is warranted.
7. With the vapor pressure of methanol being four times higher than that of water, the effective permeation rate of methanol through the HDPE liner is expected to be about four times that of water.
8. Lined pipeline operators that have used methanol for hydrate control in sour gas pipelines may want to consider inspection of those pipelines. More tools and techniques are now available that allow ILI of the pipelines and/or spot inspections.

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FIGURE 1 - Failure after insulation and coating removal

FIGURE 2 - ID of the Steel Pipe at the Failure

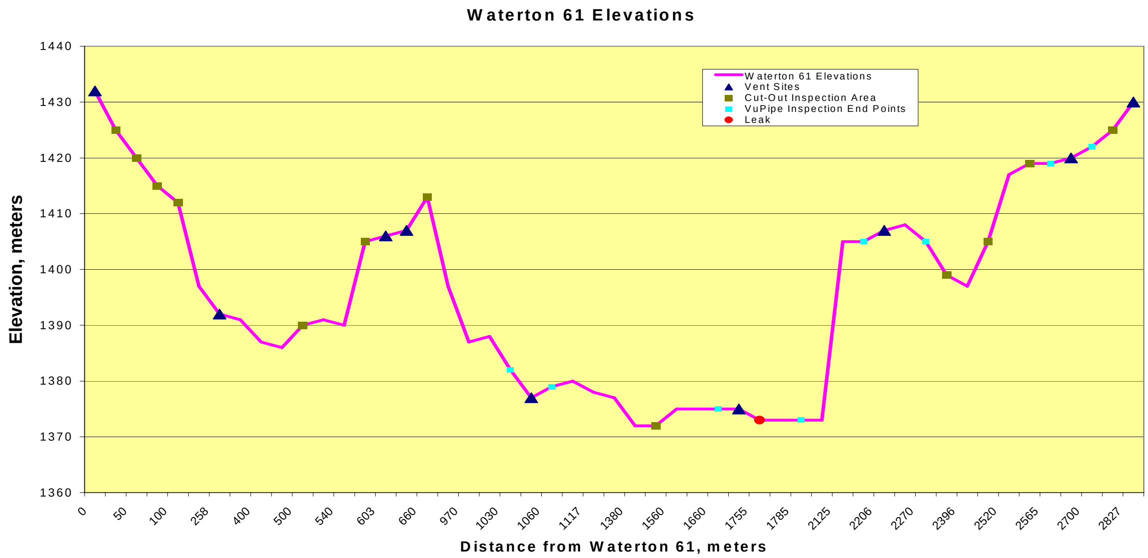

FIGURE 3 - SC Pipeline Elevation Profile and Liner Vent Location Detail

FIGURE 4 - Scale build-up and Metal loss at Bulge in Pipe Cut Out

FIGURE 5 - Band of General Wall Loss (50% Loss) and Isolated Pitting (25-30% Loss) adjacent to external grooves in the HDPE liner

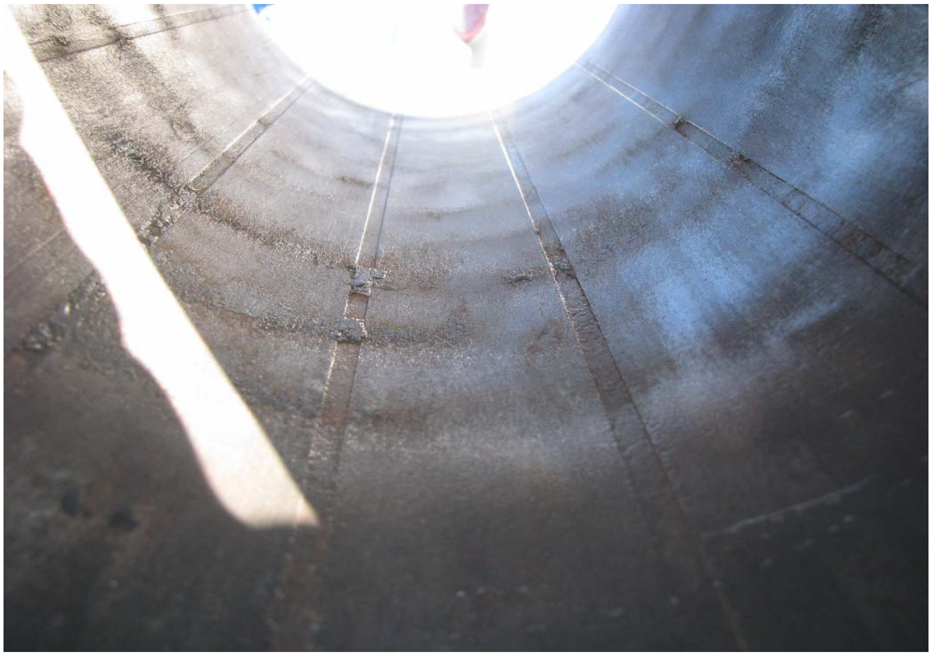

FIGURE 6 - Shallow Corrosion on Steel Pipe ID Adjacent to External Grooves in HDPE Liner