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CASE HISTORY—PEER-REVIEWED

CUI Failure of a Hot Oil Line Due to Intermittent Operations

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Abstract Insulated hot oil lines on high-temperature/intermittent duty are typically vulnerable to increased risk from corrosion under insulation (CUI) failure. This paper presents the results of an investigation into a CUI failure at an onshore natural gas-processing plant and also discusses the key issues affecting intermittent duty. The inadequate coating was degraded during high-temperature duty (up to 240 °C) followed by water ingress through degraded insulation mastic and sealant and resulting in (up to 3 mm) chain (coalesced) pitting during ambient temperature downtime, at damaged coating locations from the 2 to 10 o'clock locations. Several recommendations are proposed for addressing the underlying technical and systemic causes of the failure.

Keywords Inspections · Pitting · Corrosion failure analysis

Introduction

Hot oil is pumped from the hot oil drum to the hot oil heater and subsequently supplies heat to various parts of the gas-processing plant. An overview is shown in Fig. 1. The lines are operated once a month, for up to 5 h, to temperatures up to 240 °C. When not in operation, the system remains idle at ambient temperature for the rest of the month. The operating pressure is approximately 7 bar. The pressure at the hot oil circulation pump is 6.7 bar.

Background

The 2″ inlet and return hot oil lines to the flare drums, respectively, were visually inspected by pressure systems inspectors. Both lines were fully insulated and clad throughout the total length of 220 m. The cladding was found to be poorly sealed which represented a potential source of water into the insulation.

In order to further investigate, insulations on both lines were partially stripped and corrosion under insulation (CUI) inspection carried out. The inlet line was found to be heavily rusted, and the coating severely degraded (within the most severe fabric condition rating). The return line was, however, found to be in relatively better condition with only small patches of surface rust and minor damage to the coating.

Subsequently, both lines were fully stripped and slurry/grit blasted in preparation for ultrasonic thickness (UT) and pit depth measurement. The thickness of the inlet line pipe wall was determined to have been reduced by pitting corrosion from 4 mm to a minimum of 1 mm, at multiple sites. The pitted sites were joined together to give a chain pitting presentation (Fig. 2). There was no loss of containment. If undetected for much longer, hot heating oil could have leaked unto the unbonded ground.

A fitness for pressure service assessment was carried out, and it was determined that the line was still fit for

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continued service at the operating pressures, since the 1-mm minimum allowable wall thickness (MAWT) still exceeded the 0.3 mm threshold. As a result, a number of temporary repairs were considered but were found to be impractical or not cost effective. Given that the plant's retiral thickness threshold is 2 mm, it was eventually decided that the line should be completely replaced, painted, and thermal insulation replaced with caged protection to protect personnel from hot surfaces.

This line has been insulated for approximately 13 years and can be considered an operational (process) deadleg. Parts of this line were partially stripped and inspected the previous year. The conditions of the coating and pipework were considered adequate at the time for continued service. Much of the observed degradation is thought to have taken place within the last two years though it could possibly have occurred over a longer period. The worst-case corrosion rate for this CUI failure is approximately 3 mm/year.

Results of Investigation

Degraded Mastics and Sealants

The source of the water under insulation is thought to be rainfall which entered through degraded mastic and sealant. Poorly sealed claddings were recorded by the pressure vessel inspector. It could not be determined whether the specifications of the mastics and sealants used on these lines were appropriate for the service. However, on account of the failure experienced on this line, it can be concluded that either the specifications of the mastics and sealants used on these lines for intermittent duty were not adequate or the service life was subsequently degraded by any or combinations of the following factors: ageing, high temperatures, differential thermal expansion, and external weathering. It is recommended to review the specifications of mastics and sealants that are currently used on the terminal for insulations on high-temp/intermittent duty to ensure that this is adequate for the purpose. During plant-walk and visual inspections, inspectors should be equipped with the appropriate repair kits required for on-the-spot repair of degraded mastics and sealants.

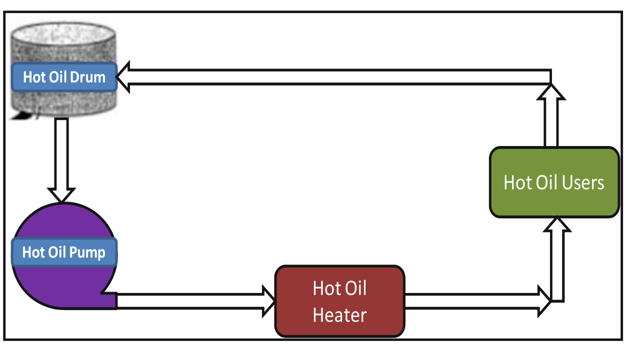

Fig. 1 Hot oil system

Protective Coating

It was not possible to determine the specification of the original coating used on this pipework. However, due to the evident coating damage, it can be inferred that the coating specification used for this hot oil line was not appropriate for high-temperature duty. The protective coating on the inlet line was inspected upon stripping the insulation and found to be severely degraded with heavy rust, flaked coatings, and a fabric condition in the most severe category. Evidently, the protective coating was damaged by repeated elevation of the service temperatures to ~240 °C. The return line which sees a lower service temperature (~165 °C) was observed to be in a comparatively much better condition with only occasional surface rust and light pitting. High temperatures can reduce the service life of off-spec protective coatings.

Though it has now been decided to operate this line without insulation, there was the need to select a suitable coating which can be used on other high-temp/insulated lines on similar cyclic duty in this plant. The paint vendor initially proposed an inorganic, zinc-rich, ethyl silicate primer, which is specified to provide corrosion protection

Fig. 2 CUI degradation on hot oil lines showing multiple coalesced pittings from 2 to 10 o'clock positions

up to 540 °C under insulation. The authors found this coating to be noncompliant with NACE RP0198-2004 Ref [1] which forbids zinc-rich coatings to be used under thermal insulation especially in the 50–150 °C service range since zinc provides inadequate corrosion resistance in closed and sometimes wet environments. Consequently, the paint company was assisted in selecting as a replacement, a heat-resistant cold spray aluminum coating, which was used to coat the Reboiler (~540 °C) during the following turn-around maintenance. Recent inspections have shown that this paint spec has performed satisfactorily on this system attesting to the success of this coating selection.

Salinity of Ingressed Water

The marine location and the severe corrosion rate experienced (up to 3 mm/year) may suggest that the ingressed water was more aggressive than normal. It was not possible to anayze the ingressed water to determine the salt content but a plausible worst-case scenario is that of air-borne salts dissolving in the rain water, carried into the insulation and then the salinity being further increased by insulation-carried salts. This may likely explain the severe corrosion rate that was experienced. Salts especially chlorides and sulfates can significantly influence corrosion rates because of their high solubility in water and the attendant increase in the conductivity of the water film. However, the salt concentration in the rainwater need not be very high as the hot surface experienced in service (up to 240 °C) could have concentrated the salt by evaporation to levels sufficient to accelerate the corrosion rate. The appropriate salt content of insulation especially for high-temperature/intermittent duty should be discussed with the manufacturers prior to installation. Experience has shown that CUI at marine locations is usually more severe by a few orders of magnitude than in nonmarine locations.

Insulation

The hot oil piping was insulated to prevent heat loss using poly propylene (PP), a closed cell, thermal insulation foam. Closed cell PP foam will be specified for high-temperature thermal insulation on carbon steel since it will not absorb water which when slowly released allows the CUI concentration mechanism to proceed. However, even with PP-closed cell insulations, once water enters the insulation system, it will eventually reach the metal surface and cause corrosion. Obviously, this was the case in the CUI degradation observed in this line.

The continued necessity for insulation on this line has been challenged by a trade off between the life-cycle energy savings and the risk of CUI. On the basis of the heat loss calculations, it was decided not to reinsulate but rather to use wire mesh guards to protect personnel from the hot surfaces.

Awareness of Increased CUI Risk of High-Temp/Intermittent Operations

This line operates for only 5 h every month, at temperatures and pressures of up to 240 °C and 7 bars, respectively. Thereafter, the line cools to ambient temperature for the rest of the month. Carbon steel piping systems that normally operate above 120 °C but experience intermittent service are categorized by API 570 as being susceptible to CUI. Above 120 °C, the risk of CUI is unlikely, but below 120 °C, the risk increases significantly. The multiple areas of coalesced pitting observed on the pipe work (with a wall thickness reduction from 4 to 1 mm) were due to the damage to the coating caused by the ~240 °C temperatures, thereby allowing direct contact of ingressed water with the steel substrate and resulting in CUI degradation at ambient temperature. Salts in the rainwater (and possibly from the insulation) were concentrated at localized pits during the high-temperature duty resulting in accelerated corrosion during the prolonged downtime at ambient temperature. The prolonged residence time of this line (~29 days per month) at ambient temperature was a significant factor in the amount of corrosion experienced.

There should be more awareness of the increased risk of CUI due to intermittent service across the plant and during the RBI process. CUI awareness sessions with the relevant staff should be planned and implemented in the short term and repeated at regular intervals.

Inspection

The risk-based inspection (RBI) process failed to identify the increased risk of CUI due to intermittent operation. It is recommended that the RBI software/process should be updated to account for the increased risk of CUI for intermittent system operation. Specifically under the deterioration mechanism section of the RBI software, cyclic temperature duty should be classified/included as a subthreat category under CUI.

Inspection Techniques for Early Detection

Investigation showed that there were minimal or no NDT techniques employed during plant walks for early detection of water or incipient CUI. Pressure systems inspectors at the plant are over reliant on visual inspection. While it is acknowledged that there is no single NDT technique that can offer 100% reliability in the detection of CUI, serious consideration should be given to employing appropriate

NDT techniques alongside visual inspection to increase the effectiveness and minimize the cost associated with a strategy based solely on strip and search. Moisture meter, Infrared thermography, and Neutron backscatter techniques should be considered for early detection of the presence of water under insulation much before the onset of corrosion. Pulsed eddy current, Profile radiography, and Long range UT can be considered for detecting incipient CUI.

Conclusions and Recommendations

1. The increased risk of CUI for Intermittent system operation was not identified by RBI (Low likelihood of CUI when operating above 120 °C, but high likelihood at ambient temps). Therefore, it is recommended to
   - Update the RBI software/process to recognize the increased risk of CUI from intermittent operations.
   - The composition of the RBI teams should include all the appropriate personnel with the required experience and expertise.
   - Identify which other intermittent systems might be a risk.
   - Review, update, and plan inspections for systems on intermittent duty.
   - Organize corrosion awareness sessions on increased CUI risk for systems on intermittent duty.
2. The protective coating was degraded by the high service temperatures (up to 240 °C), thereby allowing ingressed water to come directly into contact with the pipework. Therefore, it is recommended to
   - Specify appropriate high-temperature-resistant coating for use under insulation. A heat-resistant cold spray aluminum coating was finally selected to be used for other high-temp/intermittent systems in place of the inorganic, zinc-rich, ethyl silicate primer coating initially selected by the paint vendor. Zinc-rich coatings should not be used under thermal insulation especially in the 50–150 °C service range.
   - Challenge the requirement for insulation and replace with caged protection for personnel safety.
3. It is recommended to review the specifications of mastics and sealants that are currently used at the plant for insulations on high-temp/intermittent duty to ensure that this is adequate for the purpose. During plant-walk and visual inspections, inspectors should be equipped with the appropriate repair kits required for on-the-spot repair of degraded mastics and sealants.
4. In addition to airborne salts dissolved in the rain water and carried into the insulation, salinity may be further increased by insulation-carried salts resulting in even more severe corrosion rates under insulation. Therefore, the choice of insulation for high-temperature/intermittent duty on carbon steel should avoid insulation that will absorb water and increase the salt contents of the ingressed water available to the metal surface under insulation.
5. NDT techniques for early detection of water or incipient corrosion should be evaluated.

References

1. The Control of Corrosion Under Thermal Insulation and Fireproofing Materials—A systems Approach, NACE Standard RP0198-2004, section 4.3.5.