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Root Cause Analysis of Internal Corrosion Related Failures in a Liquid Petroleum Pipeline Transporting Export Quality Crude Oil

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ABSTRACT

The root cause of pre-mature leaks in a client's 34" crude oil pipeline due to internal corrosion was determined following the internal corrosion direct assessment Standard Practice for liquid petroleum pipelines (LP-ICDA: SP0208-2008). The 34" pipeline transports export quality crude oil with < 0.5% BS&W. The occurrence of pre-mature leaks prompted the operator to assess the extent of wall loss along the pipeline using an ultrasonic ILI tool which identified severe internal corrosion in selective pipeline regions. The root cause of these failures was then investigated using LP-ICDA methodology. In the LP-ICDA approach, the most probable locations of water accumulation and solids deposition along the pipeline were predicted as a function of the pipeline operating conditions. A comparison between the sites (i.e. locations along the pipeline) where internal corrosion was more severe and the sites where water and solids accumulation was more prevalent revealed the root cause of the failures at those selective locations in the pipeline. Advanced DNA sequencing of

the filtrate of the water associated with the crude oil also provided significant insights into the role of microbiologically influenced corrosion (MIC) in causing internal corrosion of the subject pipeline where water and solids were observed to deposit. A mitigation plan was then suggested based on the root cause analysis of the internal corrosion.

Keywords: Internal corrosion direct assessment, root cause analysis, mitigation, export crude oil pipeline

INTRODUCTION

Liquid Petroleum Internal Corrosion Direct Assessment (LP-ICDA)[1] was performed to determine the root cause of internal corrosion in a 34” x 9.53 km crude oil pipeline. The 34” pipeline run parallel to two other 34” pipeline and one 48” pipeline, all serving the same purpose. The 34” pipeline transports export quality crude oil with <0.5% BS&W to two tank farms (north tank farm (NTF) and south tank farm (STF)) from a central mixing manifold (CMM) (Figure 1). As shown in Figure 1, the 6.08 km subject pipeline section from the CMM to the NTF had 13 fill management branches and 38 storage tanks and the subject pipeline section from the CMM to the STF had 3 fill management branches and 12 storage tanks. Further, based on the presence of entry and exit points for the fluid flow along the pipeline, the NTF – CMM branch of the pipeline was divided into 11 LP-ICDA regions and the CMM – STF branch was divided into 5 LP-ICDA regions.

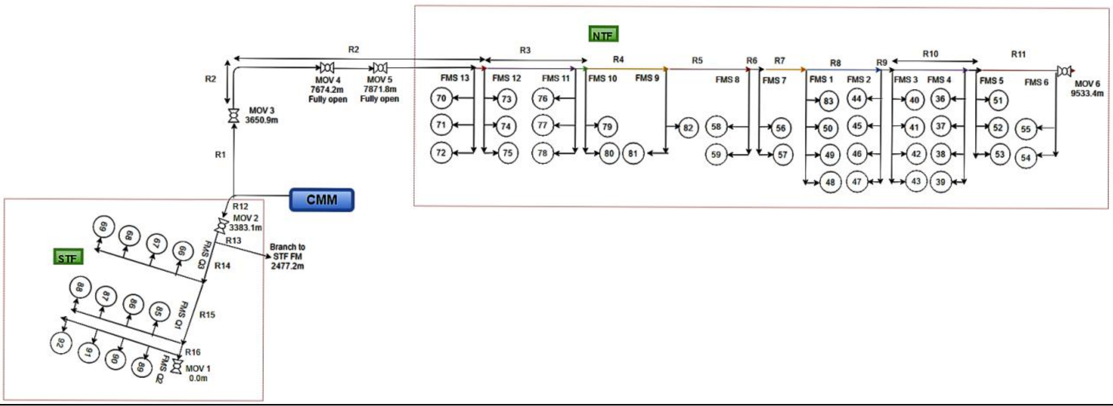

Figure 1: Flow Schematic of the 34” x 9.53 km crude oil pipeline

Figure 2 shows a broad timeline of the events for the subject 34” pipeline. The occurrence of premature leaks (less than 6 years of commissioning of the pipeline) prompted the operator to assess the extent of the wall loss along the pipeline using an ultrasonic ILI tool which identified severe internal corrosion in selective pipeline regions.

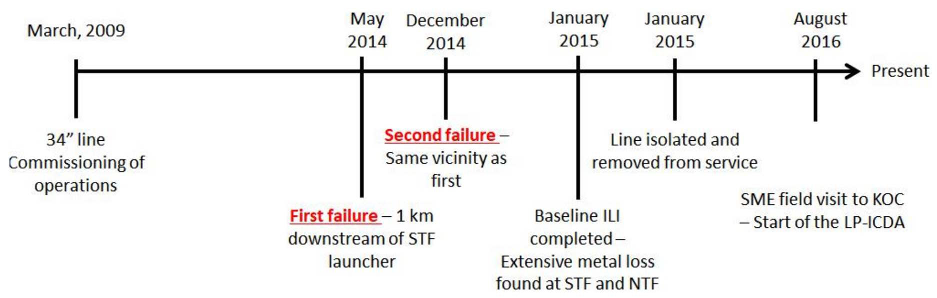

Figure 2: Timeline of events for the 34" x 9.53 km crude oil pipeline

DISCUSSION

The main objective of the internal corrosion assessment was to determine the root cause of the failures and to provide a mitigation plan to prevent internal corrosion in the pipeline moving forward. The LP-ICDA for the 34" pipeline was performed in 4 steps, namely, the pre-assessment (PrA), indirect inspection (IDi), detailed examination (DEx) and the post assessment (PoA).

PRE-ASSESSMENT

The objective of the pre-assessment was to collect, compile and verify the essential historic and present operating data of the pipeline. This includes the subject matter expert (SME) visiting the respective pipeline facilities and having discussions with the operations personnel, and on-site solids/water sampling by the SME. The data gathered include the pipeline physical characteristics (Table 1), historical operating pressure and temperature (Table 1), historical oil flow rates (Figure 3), historical analysis of the acid gases (CO_2 and H_2S) associated with the crude oil (Figure 4), pipeline elevation profile (Figure 5), historical crude oil analysis (BS&W and water content (Vol%)) (Figure 6), historical water analysis (wet chemistry parameters and ionic compositions) (Table 2) and solids (pig debris) analysis (Table 3).

Table 1: Physical characteristics and operational data for the 34" pipeline

From	CMM
To	NTF/STF
Commission date	March 2009
Outer Diameter (in)	34 in (863.6 mm)
Nominal Thickness (mm)	9.5 mm
Corrosion Allowance (mm)	3.175 mm
Material	API 5L Gr. X52, spirally welded (sour service)
Service	Crude oil
Length (km)	9.53 km
Operating Pressure (bar)	4.10 – 4.37 bar
Operating Temperature	34.0 – 46.8 ^{o}C
External Coating	Three layer extruded HDPE system

Bi-directional flow?	No
Internal Corrosion Monitoring Station	Yes (3 stations)

The historical crude oil flow rates were reported since commissioning of the pipeline in 2009. Figure 3 was compiled using numerous data points reported hourly since 2009 for each of the 50 storage tanks in the 16 FMS branches (refer to Figure 1 for the flow schematic showing the different FMS and the storage tanks). The gas to oil ratio for the crude oil was reported as 1 SCF/800 bbl and ~100 ppm of dissolved CO_2 was reported to be present in the water associated with the crude oil. Low levels (ppm) of H_2S were also measured and reported by the operator (Figure 4).

Substantially high levels of chlorides (up to 13,332 ppm) and acidic pH values (low of 4.69) were measured in the water associated with the crude oil (Table 3) indicating a high likelihood for localized pitting corrosion. Also, the presence of carbonate and sulphide in the solids (pig debris) analysis revealed the likelihood of active CO_2 and H_2S corrosion.

Further, a water sample was collected from one of the corrosion monitoring location (a low spot) and passed through a 0.22 µm filter to collect any microbes. DNA analysis (classification of microbes) and qPCR (quantification of microbes) was performed using the filter in a lab in Canada (Figure 7). The analysis revealed the microbial community was dominated by *Fuchsiella, Flexistipes, Desulfovermiculus, Caminicella, Caldimicrobium and Hydrogenophilus* which are anaerobic species indicating there is no oxygen in the pipeline and were halophilic suggesting salts may be present in high concentrations which agrees with the high chlorides present in the historical water analysis (Table 2) provided by the operator. *Fuchsiella* (which constituted 60.7% of the sample) can produce acetate and sulfide, thus performing the role of both APB and SRB and *Caminicella* (which constituted 6.5% of the sample) can produce H_2 and acids, and forms biofilms. Thus, there is a high likelihood of microbiologically influenced corrosion (MIC) in the 34" pipeline. The MIC analysis was above and beyond the requirements of the LP-ICDA standard practice nevertheless was essential to understand the root cause of internal corrosion of the 34" pipeline.

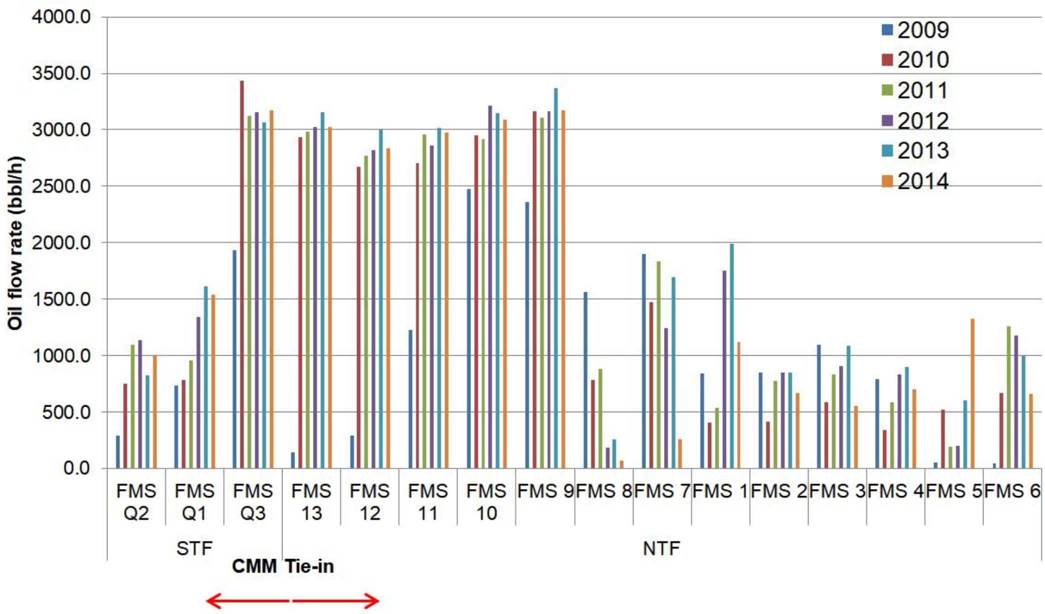

Figure 3: Historical crude oil flow rates (barrels per hour) through the 34” pipeline

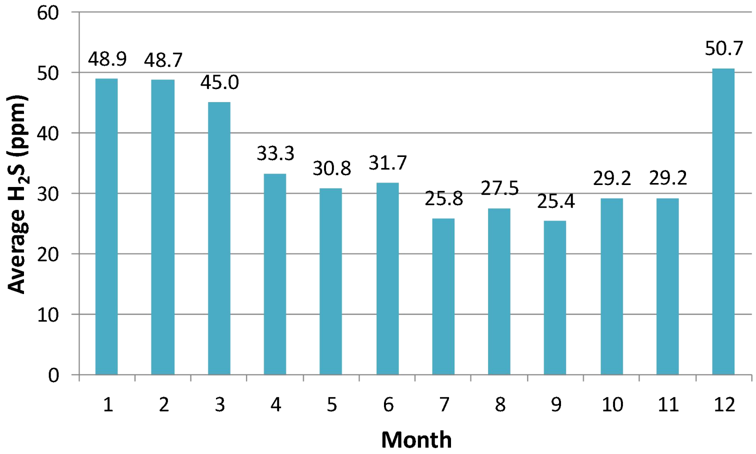

Figure 4: H_2S measured in the 34” pipeline

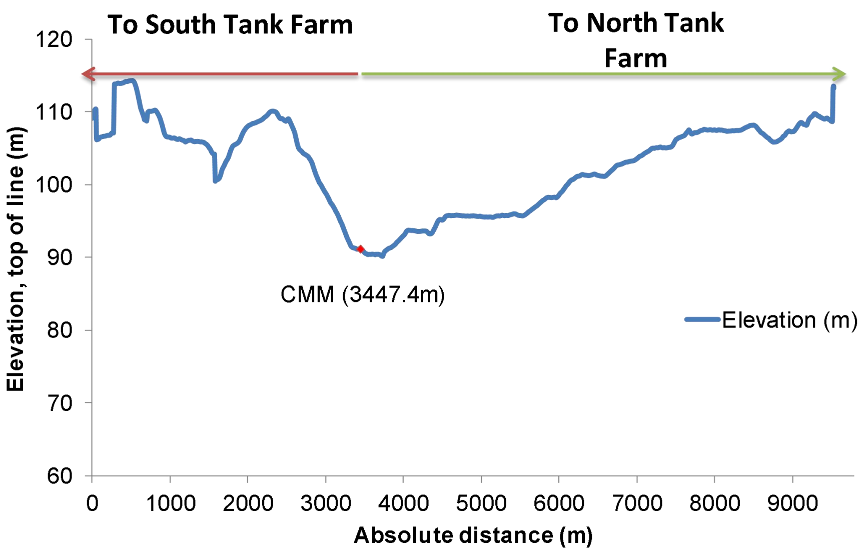

Figure 5: 34” pipeline elevation profile and the direction of fluid flow from CMM

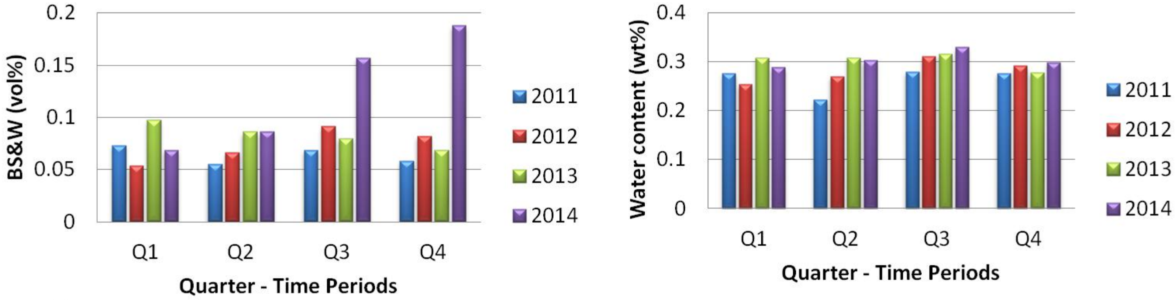

Figure 6: Historical crude oil analysis (BS&W and water content)

Table 2: Water analysis data for the 34” Pipeline

Sampled Date/ TESTS	**30/1/2012**	**6/2/2012**	**22/05/2012**	**10/3/2013**	**9/10/2013**	**9/1/2014**
pH	4.69	5.18	6.2	6.8	5.65	5.3
Cl^- (ppm)	5659	13332	3109	3458	-	6.3
Fe^{2+} (ppm)	550	133	5.9	155	465	0.18
Mn^{2+} (ppm)	-	-	-	2.5	134	0
Ca^{2+} (ppm)	1760	2204	62	795	2023	5
Mg^{2+} (ppm)	458	497	31	147	362	1.5
SO_4^{2-} (ppm)	236	222	62	-	-	3
Soluble Sulphide (ppm)	0.9	0.39	-	-	-	0.003
Corrosion Inhibitor residual (ppm)	13.5	42.7	164	-	-	-

Table 3: Solids (pig debris) analysis data for the 34” Pipeline

Sampled Date/ TESTS	6/2/2012	22/05/2012	10/3/2013	9/10/2013
Color & Appearance	Dark Brown & Oily sludge	Black & Oily sludge	Brown & Oily sludge	Brown & Oily sludge
Loss On Drying (% wt. loss @ 100ºC/2hrs)	14.3	34.7	18.5	29.4
Carbonates (% wt. loss @ 900ºC/2hrs)	2.9	6.3	3.5	3.8
Presence of Sulphides (qualitative)	Positive	Positive	Positive	Positive

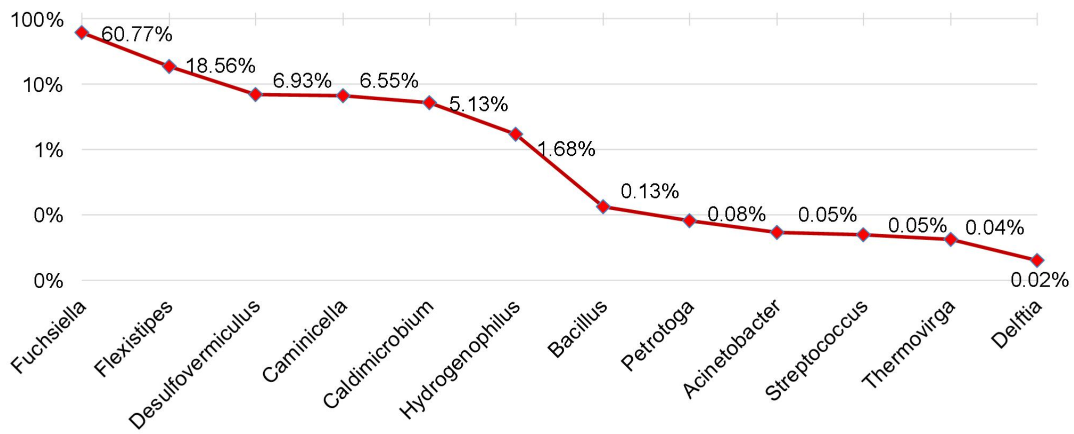

Figure 7: Rank abundance curve showing the most dominant species of microbes in the sample

INDIRECT INSPECTION AND DETAILED EXAMINATION

The objective of the indirect inspection (step 2 of the LP-ICDA standard practice) was to perform multiphase flow simulations using the data collected in the pre-assessment stage and calculate the inclination angles, critical velocity and sweep velocity for water accumulation, uniform corrosion rates, effect of concentration of chlorides on the pitting corrosion, and the cumulative metal loss of the pipeline. The LP-ICDA standard requires calculating a probability of internal corrosion and not necessarily quantifying the internal corrosion rates of the pipeline. However, internal corrosion rates of the 34” pipeline were quantified using the Teevens model (cited in Appendix (non-mandatory) A, C and D of the NACE International LP-ICDA Standard Practice (SP0208-2008) and the newly released, multiphase internal corrosion direct assessment (MP-ICDA) (SP0116-2016) standard practice) following the guidelines of the NACE International Standard Practice for multiphase pipeline internal corrosion direct assessment (MP-ICDA: SP0116-2016)[2].

Figure 8 shows the uniform/general corrosion rates calculated using the data collected from the pre-assessment stage, the most influencing factors of uniform corrosion rates being the average flow rates (Figure 3), the concentration of the acid gases (CO_2 (~100 ppm dissolved in the water phase) and H_2S) (H_2S levels shown in Figure 4), the operating pressure and temperature (given in Table 1) and the elevation profile of the pipeline. The uniform corrosion rates for the two branches from CMM (i.e CMM – NTF and CMM – STF) were calculated for two time periods based on the flow variations (Figure 3). As observed from Figure 8, the predicted uniform corrosion rates were low (<1 mpy) and are not expected to cause significant damage to the 34" pipeline. However, the pipeline had failed (or leaked) in ~5.8 years which show the dominant mechanism of internal corrosion is localized pitting corrosion. The influencing factors for localized corrosion include possible solids/water accumulation, presence of high levels of chlorides (Table 2), and presence of corrosive microbes in the pipeline (Figure 7) along with the presence of acid gases in the pipeline.

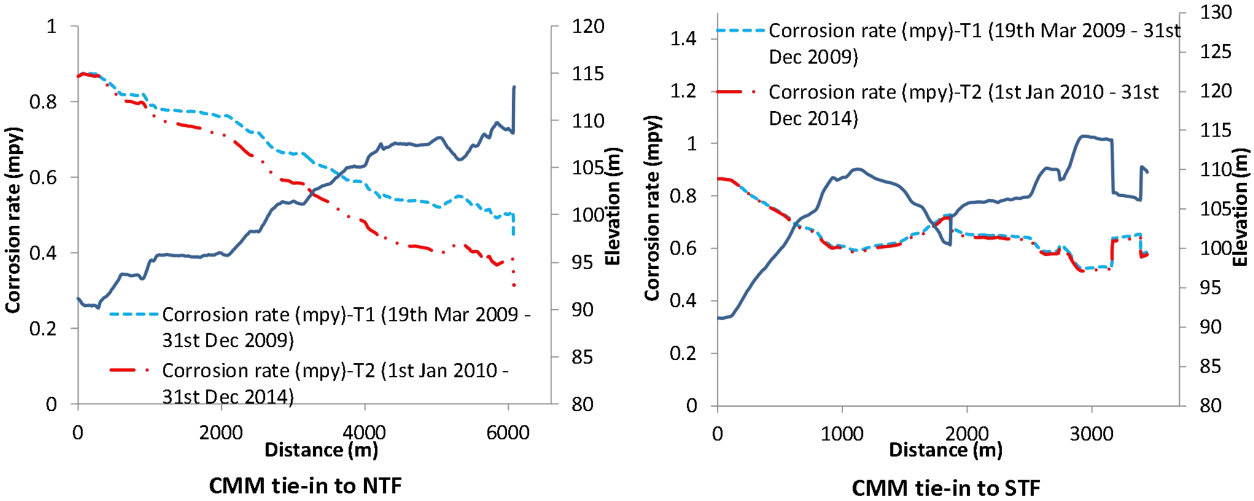

Figure 8: Predicted uniform corrosion rates for the two branches of the 34" pipeline

Solids and water accumulation were calculated along the 34" pipeline. The actual wall loss data of the pipeline was provided by the contractor (Inline Inspection (ILI) was done in Jan 2015) and hence the subject matter experts (SME's) were able to compare the predictions for solid and water accumulation with the actual measured damage. As shown in Figure 9 and 10, the regions along the line where severe solids and water accumulation were predicted were mostly the pipeline regions which suffered from severe wall loss due to internal corrosion. These regions with severe internal corrosion had fluid velocities lower than the calculated sweep velocity (i.e. the velocity required to move water from the low spots). The model was used to predict the solids deposition using a particle size of solids (~150μ) and the density of the solids (~2500 kg/m^3) along with the other operating parameters as inputs required for the flow modeling. The water accumulation profiles were calculated using the equations provided in Appendix A of the LP-ICDA standard practice (SP0208-2008).

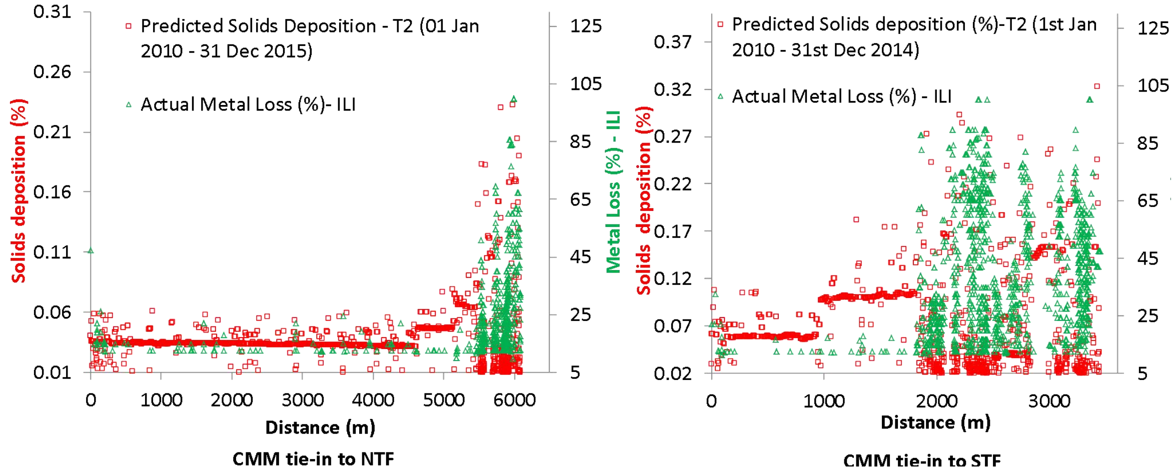

Figure 8: Comparison between the predicted solids deposition and actual wall loss for the two branches of the 34" pipeline

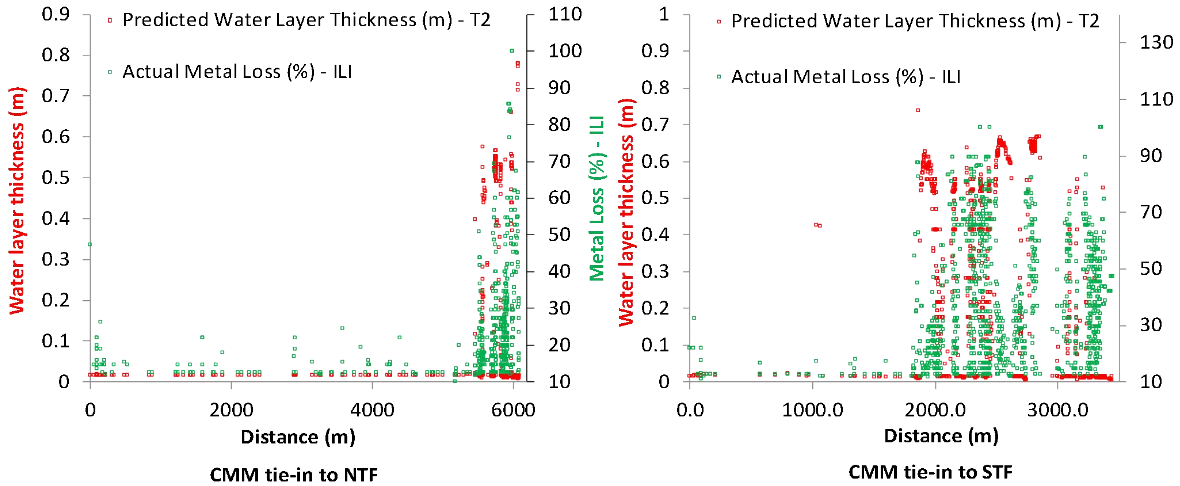

Figure 9: Comparison between the predicted water accumulation and actual wall loss for the two branches of the 34" pipeline

Further the effect of chloride concentrations (obtained from the water analysis) on the localized pitting corrosion of the 34" pipeline was studied. The model, as shown in Figure 10 predicts the pitting corrosion rates at different combinations of Cl^- ion and Fe^{2+} ion concentrations (Table 2) at average operating conditions of the 34" pipeline (0.28 MPa, 41°C, 100 ppm dissolved CO_2 and 35 ppm H_2S). At the levels of chloride concentrations observed in Figure 10, localized pitting corrosion can be initiated in the 34" pipeline but the resultant pitting corrosion was not observed to go autocatalytic i.e. the corrosion pits formed in the 34" pipeline was predicted to passivate in about 59 – 72 days. However, the 34" pipeline had two leaks and severe internal corrosion anomalies were found by the ILI tool. Hence, there exists a possible synergistic relationship between the halophilic microbes found in the DNA analysis (Figure 7) and the high chloride concentrations found in the water associated with the crude oil carried by the pipeline. This synergistic relationship along with other contributing factors discussed above has resulted in the severe internal corrosion found in the 34" pipeline.

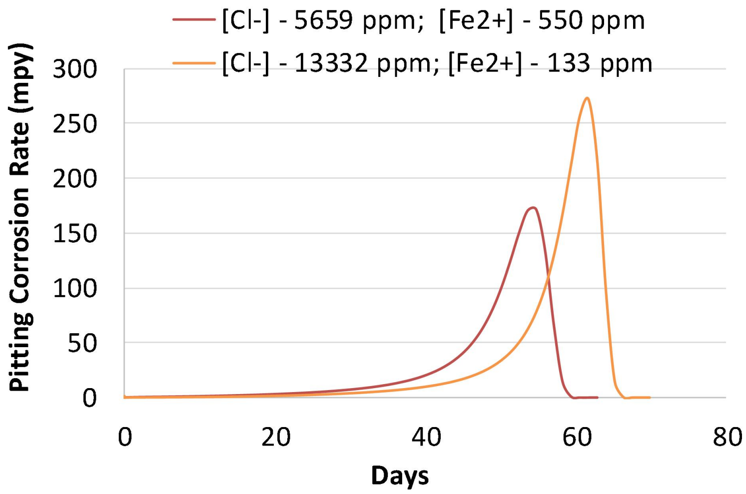

Figure 10: Effect of chloride ion concentration on pitting corrosion rate

Following the determination of the causal factors of internal corrosion in the 34” pipeline as discussed above, the cumulative wall loss (contributed by uniform and localized corrosion) of the 34” pipeline was predicted. The cumulative metal loss (ML) of the 34” pipeline in each region was obtained using dynamic pitting factors developed as a function of the calculated water accumulation, solids deposition, local pressure variations and the chloride levels.

$$ML_{Cumulative,i} = ML_{GeneralCorrosion,i} \text{ X } F_{pitting,i} \quad (1)$$

$$F_{pitting,i} = C \text{ X } (F_{water,i})^a \text{ X } (F_{solids,i})^b \text{ X } (F_{pressure,i})^c \text{ X } F_{Cl^-} \quad (2)$$

Where, C is an empirical constant; $F_{water,I}$ is the water accumulation factor of the ith region; $F_{solids,i}$ is the solids deposition factor of the ith region; $F_{Cl^-,I}$ is the chloride ion factor of the ith region; $F_{pressure,I}$ is the pressure factor of the ith region; and a, b and d are constants for a region.

The detailed examination (step 3 of the LP-ICDA) is the comparison of the predictions with the actuals. The cumulative metal loss predicted by the dynamic pitting factor model was in good agreement with the metal loss measured by ILI for the 34” pipeline (Figure 11 and Figure 12). On a region-by-region basis, the range of differences between predicted vs. actual has a low (or under-calling damage) by -8.6% and a high (over-calling damage) by +2.95% for the NTF leg from the CMM and -0.67% and +0.53% for the STF leg from the CMM (Figure 13 and Figure 14).

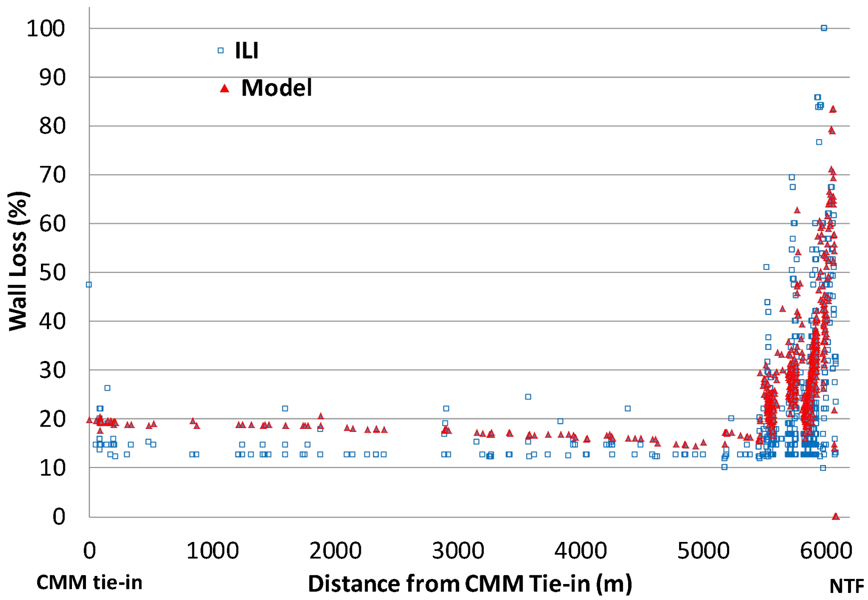

Figure 11: Comparison between model predictions and ILI measurements (CMM – NTF)

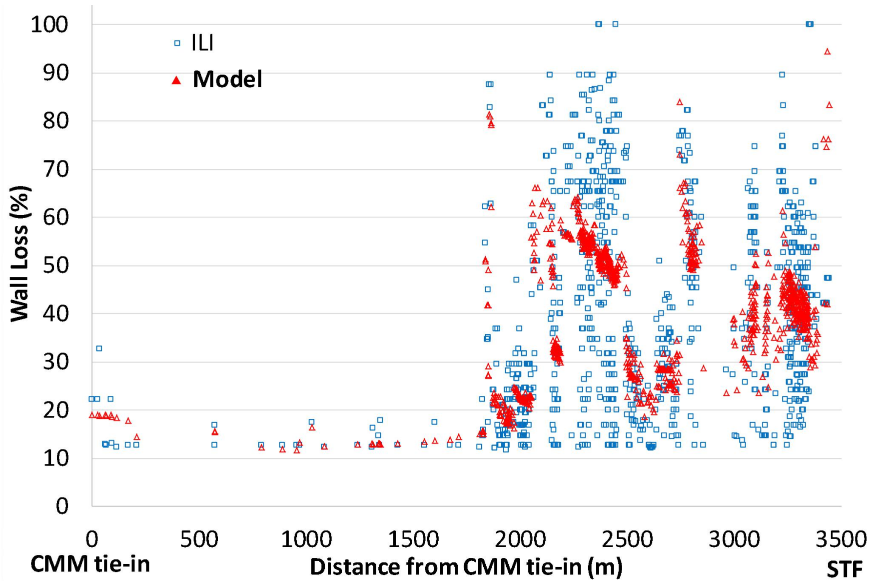

Figure 12: Comparison between model predictions and ILI measurements (CMM – STF)

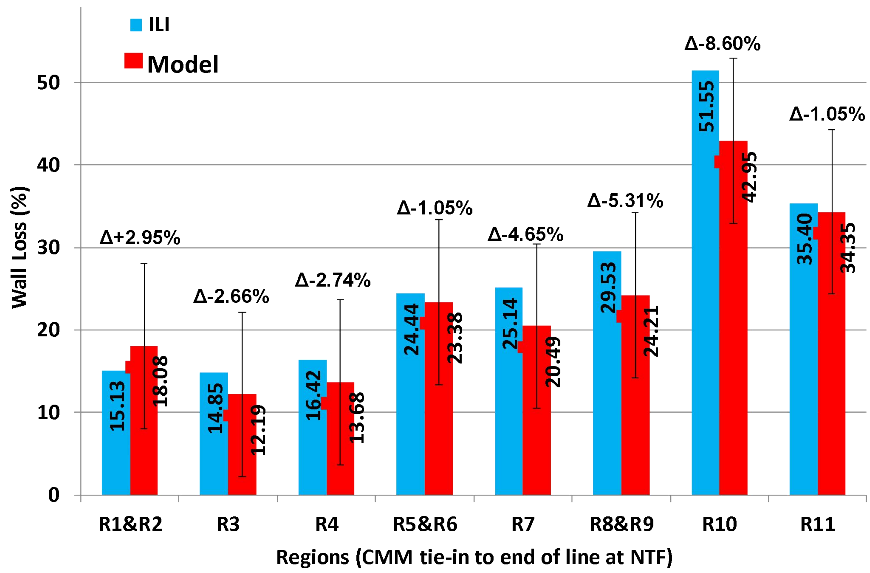

Figure 13: Region-wise comparison between model predictions and ILI measurements (CMM – NTF)

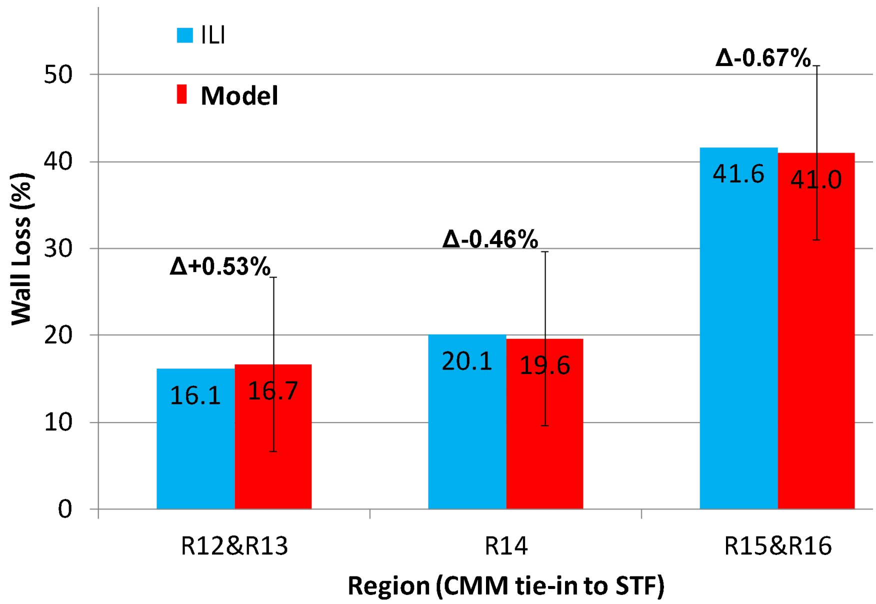

Figure 14: Region-wise comparison between model predictions and ILI measurements (CMM – STF)

POST ASSESSMENT

The major objective of the post assessment was to identify the root cause of the internal corrosion in the 34” pipeline and to develop a mitigation plan to prevent internal corrosion. The root cause of internal corrosion in the 34” pipeline include the slow moving liquids (i.e. low oil velocity) in selective regions causing water accumulation and solids deposition, initiation and acceleration of under-deposit pitting corrosion under a high chloride ion concentration, and possible Microbiologically Influenced Corrosion (MIC). The mitigation plan as put forward is summarized in Figure 15.

As shown in Figure 15, combining the throughputs from the CMM into one 34” line (the subject pipeline runs parallel to two 34” pipelines and one 48” pipeline) will increase the liquid velocities in the pipeline regions which were hitherto experiencing low liquid velocities and prevent excessive water accumulation in these regions.

Solids deposition was inevitable in most pipeline regions (the calculated critical velocity of solids was 5.40 m/s for solids of particle size < 150 microns). Hence, in addition to combining throughputs, cleaning pigging of the pipeline was recommended.

Based on the amounts of chlorides present in the deposits, a maintenance cleaning pigging frequency of ~30 days (1 month) was suggested. Also, to combat the risk of MIC, batch treatment of the line with biocide post cleaning pigging along with a customized chemical treatment program was recommended. The chemical treatment program should enable a protective film to be formed on the metal surface of the subject 34” pipeline and prevent internal corrosion due to dissolved acid gases (CO_2 and H_2S).

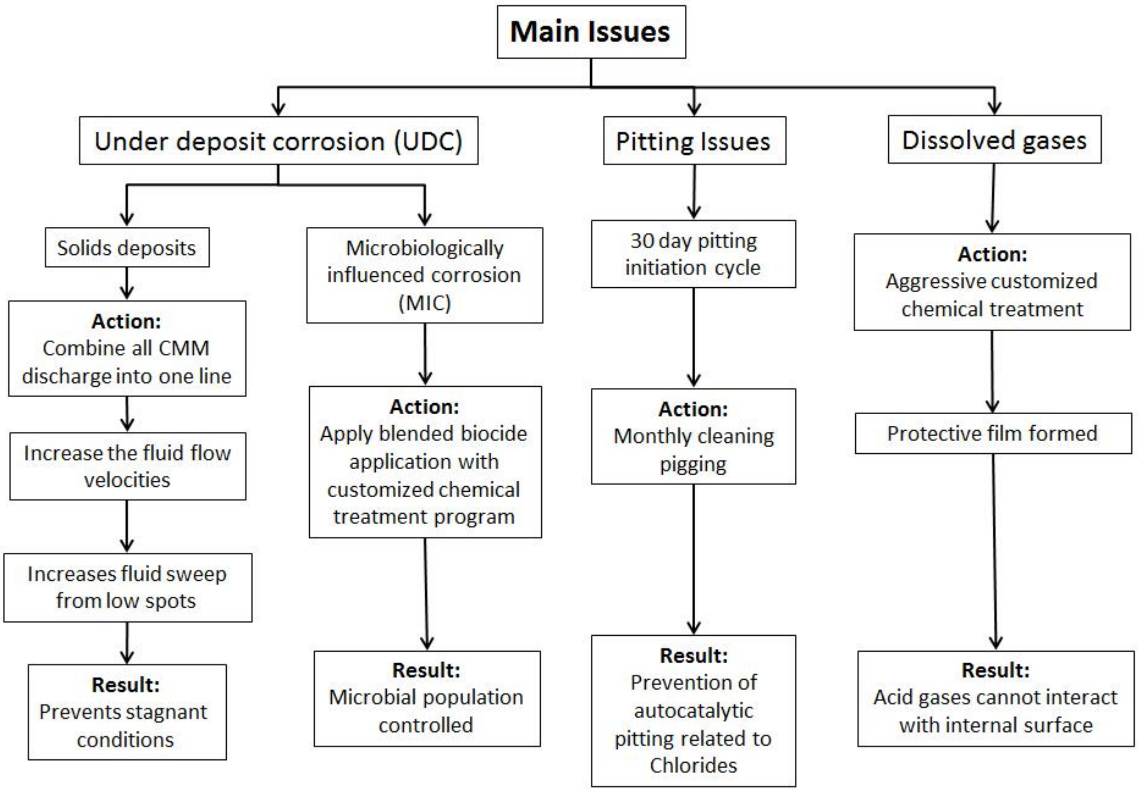

Figure 15: Recommendations for internal corrosion mitigation of the 34” pipeline

CONCLUSIONS

NACE Internal Standard Practice's for liquid petroleum internal corrosion direct assessment (LP-ICDA: SP0208-2008) and multiphase pipeline internal corrosion direct assessment (MP-ICDA: SP0116-2016) was successfully applied to determine the root cause of internal corrosion in a 34" pipeline carrying export quality crude oil. The internal corrosion predictive modeling (ICPM) results showed excellent correlation with the average measured ILI data wherein the ICPM results when compared to actual are within ±10%, as defined in Section 5.1.5, page 23 of the MP-ICDA Standard Practice. ICDA has been demonstrated to be an effective integrity validation and assessment tool which is complementary to ILI.

REFERENCES

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2. NACE International Standard Practice, SP0116-2016, Internal Corrosion Direct Assessment Methodology for Multiphase Petroleum Pipelines, (NACE International, Houston, TX), 2016