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Corrosion Investigation of an Oil and Gas Pipe Section and Prediction of its Future Performance

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Abstract

Pipelines are regarded as one of the safest and most economical means of transporting oil and gas. However, pipelines constructed from carbon steels are susceptible to corrosion, and hence, corrosion evaluation and determination of the best mitigation strategies are of utmost importance. In this paper, the internal corrosion characteristics of a pipe section was evaluated using iFILMS® software.

Analysis indicated that the pipe section (outer diameter 114.3 mm and wall thickness 3.17 mm) installed in 2015 would undergo internal corrosion in the form of microbiologically influenced corrosion (MIC) and top of the line corrosion (TLC) at a rate of 0.266 mm/y. Implementation of annual cleaning and batch treatment would decrease corrosion rate to less than 0.043 mm/y. With this strategy, it is projected that the pipe section would continue its operation without much decrease in the wall thickness due to internal corrosion until 2025. It is also recommended to monitor the pipeline to ensure that the mitigation strategy suggested would continue to work and to revaluate the internal corrosion strategies again in 2025.

1. Introduction

With the rapid growth of society, demand for oil and gas has been increasing. As one of the main means of transporting oil and gas, pipelines have the advantage of low cost, fast and convenient operation, and large transportation volume. Unfortunately, these pipelines are prone to external and internal corrosion, which would not only cause huge economic losses but also result in environmental damage [1]–[3]. Figure 1 represents the key factors in failure of Alberta production pipelines and their share from 1980 to 2005. About 70 % of failures were due to corrosion; of which about 58 % were because of internal corrosion and 12 % because of external corrosion [4]. As a result, proper assessment of corrosion phenomena and estimation of remaining life of the oil and gas pipelines is vital.

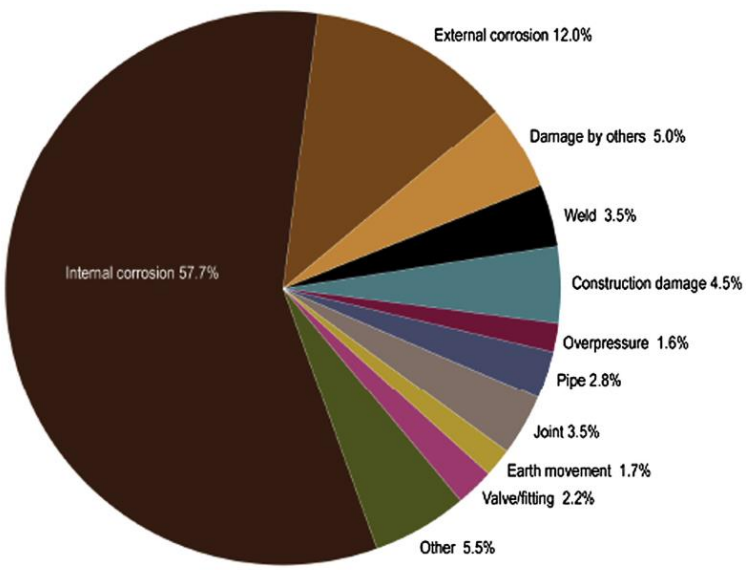

Figure 1. Alberta, Canada production pipeline incidents and their causes from 1980 to 2005 [4].

To have a proper estimation of internal corrosion threat, it is vital to consider all factors including temperature, flow, pressure, composition of oil phase, water phase and gas phase, solids, microbes, pH, and organic acids [4].

2. Model

The pipeline section investigated in this project was installed in 2015. The internal corrosion status was evaluated as of June 2020 and strategies to maintain the pipeline until 2025 was predicted in this analysis.

The operational condition of the pipe section analyzed in the project is summarized in Table 1.

Table 1. Summary of the operational condition of the pipe section.

Oil flow rate (m^3/d)	Water flow rate (m^3/d)	Gas flow rate (m^3/d)	Temp. (°C)	Total pressure (kPa)	P_{H2S} (mol %)	P_{CO2} (mol %)	Sulfur (g/m^3)	Bicarbonate (g/m^3)	Chloride (g/m^3)	Solid (g/m^3)
26	1.3	10	60	4840	0	0	28557	0	0	0

The pipe section material is X52; the chemical composition is listed in Table 2. The designation X corresponds to the pipe section grade and the 52 digits correspond to the minimum specified yield strength in ksi. X52 steel belongs to the high strength low alloy (HSLA) steels family which have high strength and excellent toughness, attributed in part to grain refinement and the presence of precipitates, especially nano-size precipitates. HSLA steels are broadly used for transport pipelines because of their beneficial mechanical properties, excellent weldability and, above all, relatively low cost [5], [6], [7].

Table 2. Chemical composition of the pipe section.

Element	C	Mn	P	S	Si	V	Ni	Cr	Cu	Mo	Al	Nb	W	Ti	Fe
wt%	0.2	0.1	0.012	0.007	0.28	0.01	0.02	0.016	0.007	0.03	0.043	0.01	0.02	0.011	Remaining

The outer diameter, wall thickness, and length of the pipe section are 114.3 mm, 3.17 mm, and 33 m respectively. Figure 2a to c show the variation of elevation, temperature, and pressure along the pipe section length.

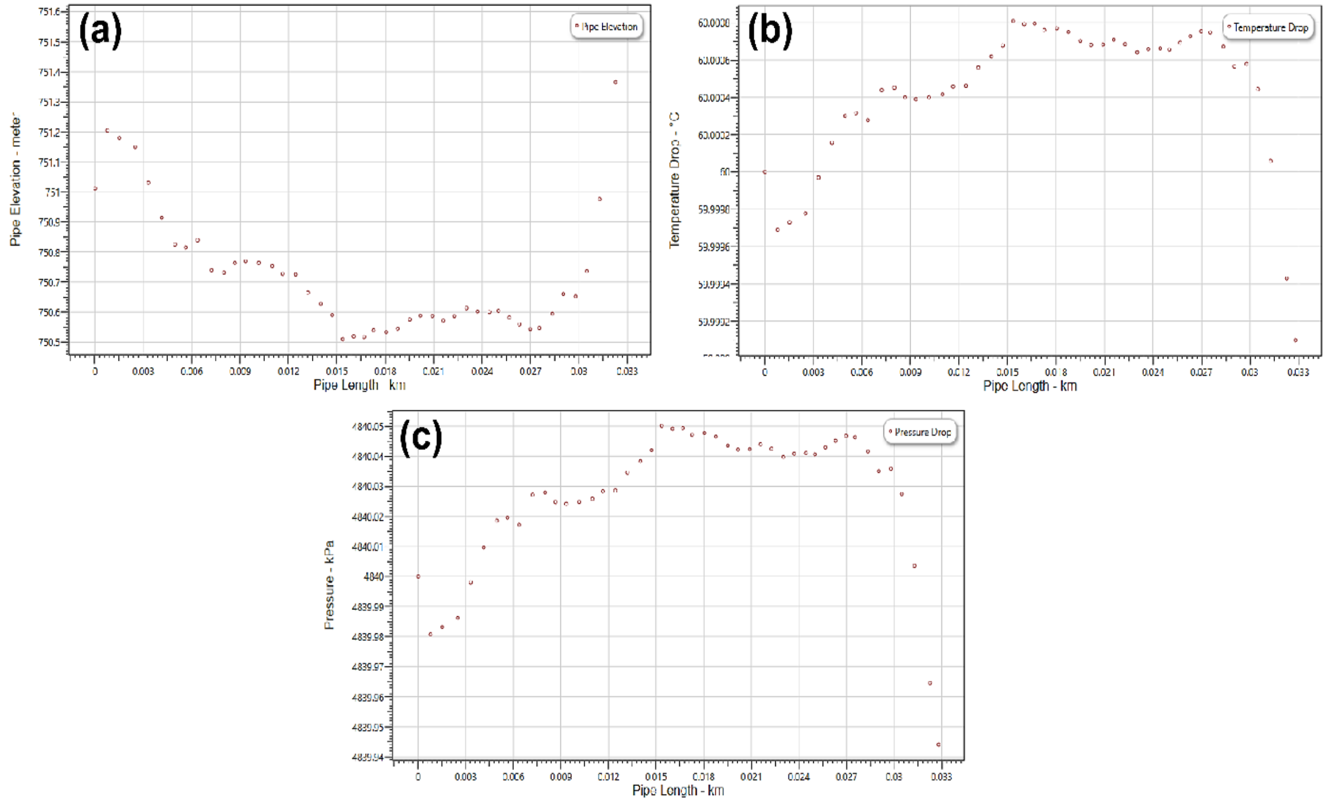

Figure 2. Variation of (a) elevation, (b) temperature, and (c) pressure along the pipe section length.

Internal corrosion in pipelines occurs when water accumulates, therefore, determining the locations where water may accumulate is essential. Several factors including oil, water, and gas characteristics, pipe inclination, flow velocity, and roughness of pipeline affect the water accumulation. To predict the locations of water accumulation, three broad categories are established: single phase oil, single phase gas, and multi phase. Single-phase oil flow occurs when:

$$\left(\frac{P.R._{oil}}{P.R._{oil}+P.R._{water}+P.R._{gas}}\right) > 0.95 \qquad (1)$$

Single-phase gas flow occurs when:

$$\left(\frac{P.R._{gas}}{P.R._{oil}+P.R._{water}}\right) > 5,000 \qquad (2)$$

where $P.R._{gas}$, $P.R._{oil}$, and $P.R._{water}$ are the production rates of gas, oil, and water, respectively. The flow is considered to be multiphase when it does not meet the conditions of Equations 1 or 2 [4]. According to the Table 1 and Equations 1 and 2, the flow in this study is multiphase.

Figure 3a presents water accumulation locations as predicted by iFilm® software. Internal corrosion would take place in all locations where water accumulates. In some locations, the flow regime was bubble flow and in some it was stratified (Figure 3b).

According to the iFilm® software analysis (Figure 4), the dominant corrosion mechanisms in locations with water accumulation are Microbiologically influenced corrosion (MIC) and top of line corrosion (TLC). MIC is a major internal corrosion threat in pipelines. The primary parameters influencing MIC caused by sulphate reducing bacteria (SRB) are sulfate, nutrients, bacteria type, pH, flow rate, salinity, and temperature. Oil and gas pipelines are internally affected by MIC, especially in water pockets at low-lying sections. MIC is observed mostly in localized corrosion configuration and is attributed to stagnant conditions of flow inside pipelines and could result in severe pitting mainly at 6 O'clock position [8], [9].

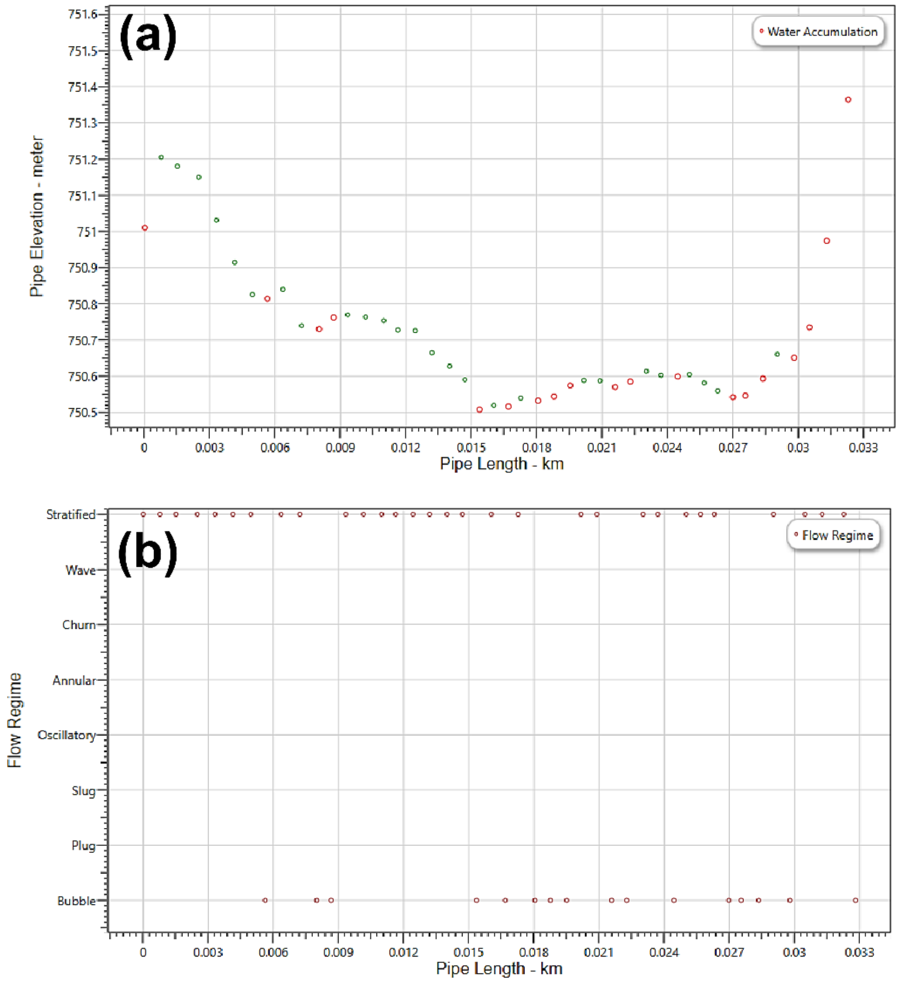

Figure 3. (a) Locations of water accumulation and (b) Variation of flow regime along the pipe section length.

TLC occurs in wet gas transportation, due to temperature gradients between the internal medium and the surrounding environment. When this occurs, water vapour condenses on the whole circumference of the internal walls of the pipe. In such conditions, the condensed water is in equilibrium with the gas phase. Since most of the condensing water drains downward under the effect of gravity, corrosion is also expected to occur at the bottom of the line. Under sustained dewing conditions, a continuous thin film of liquid nevertheless forms on the internal top surface [10], [11].

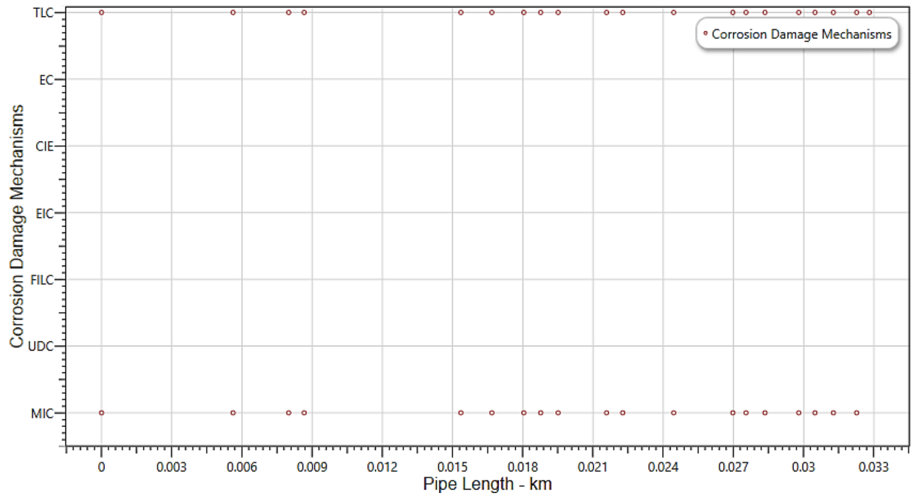

Figure 4. Dominant corrosion mechanism along the pipe section length.

Figure 5 shows the variation of pitting corrosion rate along the pipe section length. In locations with water accumulation, higher rate of corrosion (0.27 mm/y) was observed. Due to higher corrosion rate, the pipe section requires mitigation strategies [12], [13].

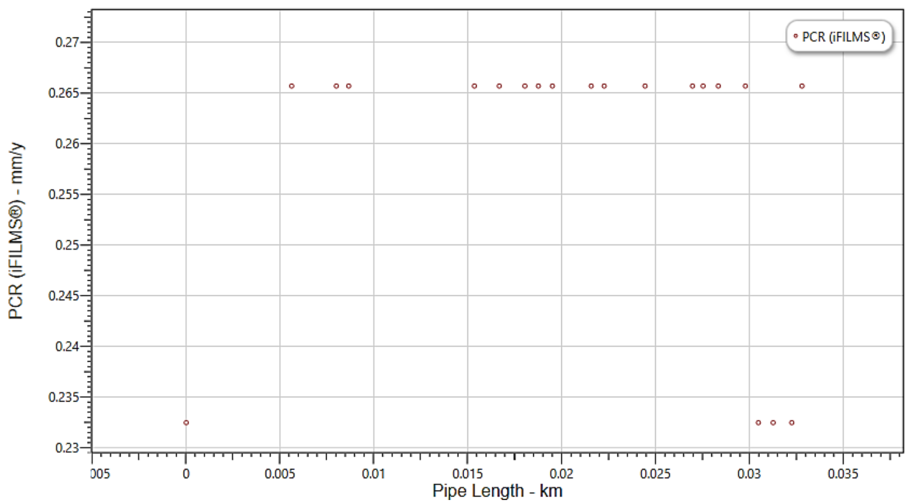

Figure 5. Variation of pitting corrosion rate along the pipe section length in the absence of any mitigation strategies.

3. Mitigation

The most common preventive maintenance methods of pipelines include batch corrosion inhibitor, internal coating, and pigging [14]. Variation of pitting corrosion rate along the pipe section length after application of annual batch inhibitor, annual pigging, and simultaneous batch inhibitor and pigging is shown in Figure 6a to c, respectively. Based on the results, a combination of pigging and batch inhibitor treatment would keep the pitting corrosion rate below 0.043 mm/y (Figure 6.c).

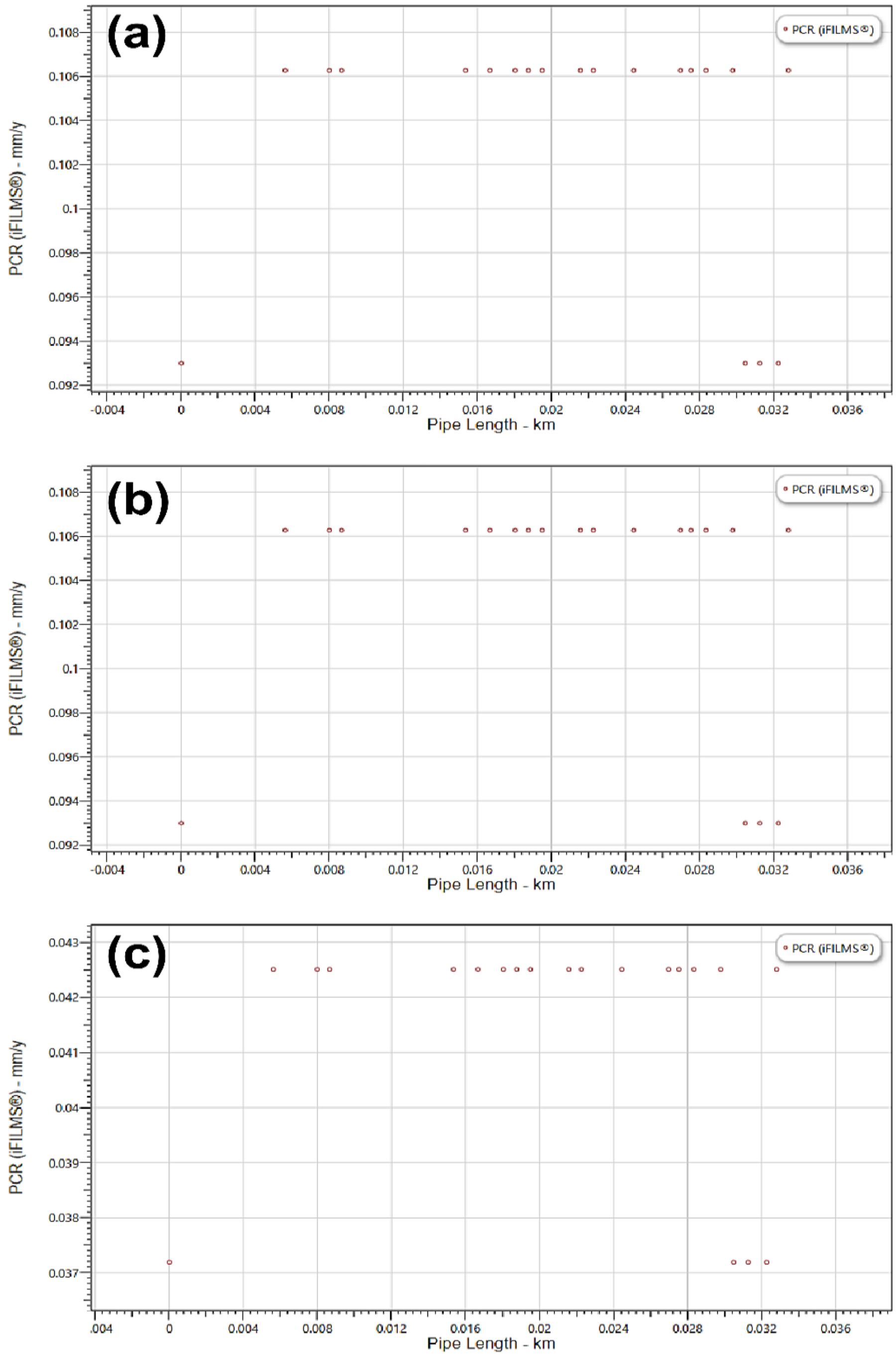

Figure 6. Variation of pitting corrosion rate along the pipe section length after application of (a) annual batch inhibitor, (b) annual pigging, and (c) simultaneous annual batch inhibitor and annual pigging.

In the absence of any mitigation strategies, the minimum remaining wall thickness (about 2.1 mm) happened in locations with water accumulation (Figure 7). According to the API Recommended Practice 574 (Inspection Practices for Piping System Components), the minimum structural thickness of a pipe with NPS=4 (outer diameter of 114.3 mm) at temperatures up to 205 °C is 2.3 mm [15]. Thus, in the absence of any mitigation strategies the pipeline will be at risk due to internal corrosion.

After application of simultaneous annual batch inhibitor and annual pigging, minimum wall thickness of the pipe would be about 3 mm (Figure 8) which meets the criteria of the API Recommended Practice 574. Consequently, the pipe section could operate without problem.

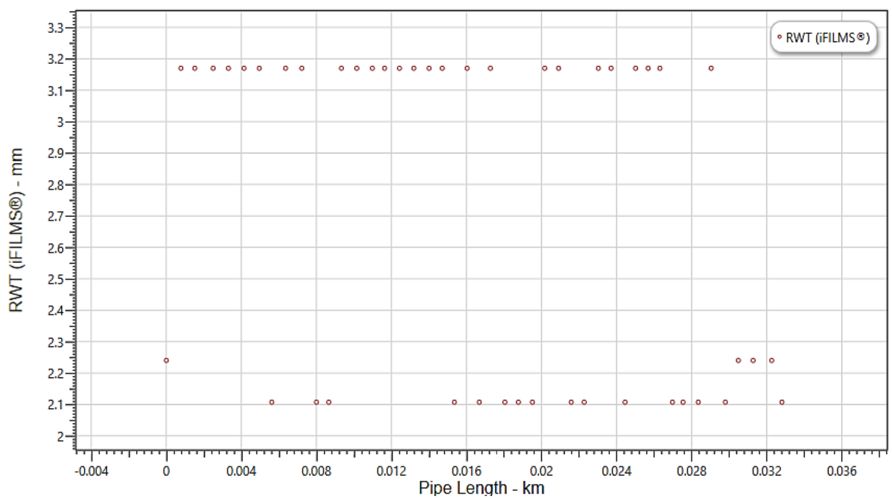

Figure 7. Variation of remaining wall thickness along the pipe section length without any mitigation strategies

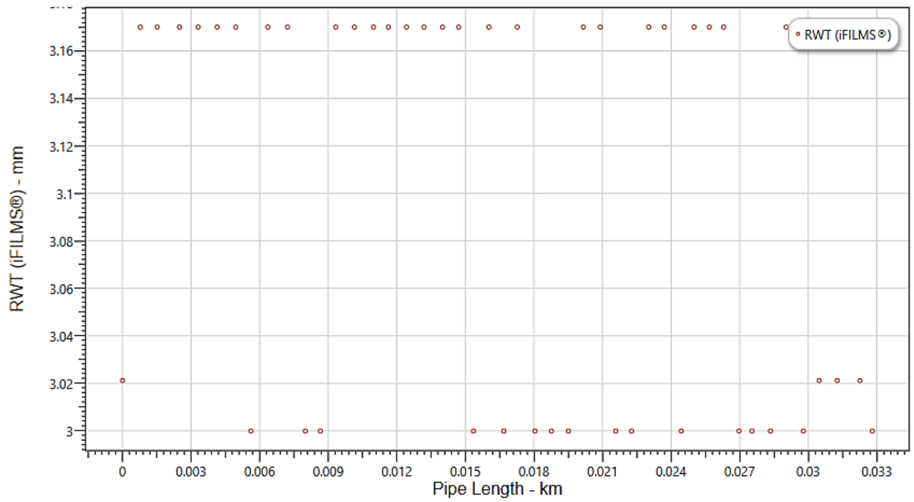

Figure 8. Variation of remaining wall thickness along the pipe section length after application of simultaneous annual batch inhibitor and annual pigging.

4. Monitoring

Monitoring of the effectiveness of the suggested corrosion control methods is very important, because if they can not prevent the corrosion, unexpected failure would occur. In this regard, it is suggested that the remaining wall thickness of the pipe be evaluated one year after commissioning of mitigation and then biannually with the Guided Wave UT Inspection method.

5. Maintenance

In this project it is assumed that the pipe section undergoes normal operating condition for the period of operation. The minimum acceptable wall thickness of the pipe is 2.3 mm. Also, the maximum allowed corrosion rate was assumed to be 0.1 mm/yr. Due to economic consideration, the batch inhibitor and pigging operations would be performed once a year. To be effective, maintenance activities should be performed by qualified personnel.

6. Management

It is recommended to review the corrosion control activities annually. Result of these activities could be a guideline for corrosion engineers to improve the accuracy of their control.

7. Summary

According to the iFILMS® software analysis, without any mitigation strategy, the remaining wall thickness in 2025 would not be adequate, hence the pipe section would fail. However, with the simultaneous application of annual batch inhibitor and pigging, the corrosion rate of the pipe section would be under control and the pipe can continue its safe operation.

8. Conclusion

In this study, iFILMS® software was employed to evaluate internal corrosion condition and to predict the performance of a specific pipe section up to 2025. The maximum pitting corrosion rate and the remaining wall thickness of the pipe in 2025 were predicted to be about 0.226 mm/yr and 2.1 mm, respectively. These results necessitated the application of mitigation strategy. When a simultaneous use of batch inhibitor and pigging was considered, the corrosion rate reduced to 0.043 mm/yr, showing that the pipe section can continue its operation without failure.

The results highlight the importance of corrosion evaluation and remaining life prediction in pipelines to decrease the economical, environmental, and health risks. In this regard, application of engineering software such as iFILMS® can be useful in achieving an overall view about the corrosion mechanism, corrosion kinetics, and the appropriate mitigation strategies.

9. Acknowledgement

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