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Corrosion Under Insulation Probability of Failure Prediction Framework Accordance with API 581

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Abstract

This paper proposed a framework for prediction of corrosion under insulation (CUI) probability of failure (PoF) based on the risk-based inspection (RBI) methodology outlines in API 581. Despite the advancement of CUI inspection technologies and prediction methods available, there are still limitations leading to uncertainties in CUI predictions. This is due to CUI occurrence that is influenced by many factors besides the presence of moisture and operating temperatures. API 581 guidelines in PoF calculation integrate many CUI contributing factors compared to other available industrial standards, making it a more holistic and conservative approach for CUI potential failure prediction. The framework proposed in this paper is an improvised version from the API 581 approach which provides a focused and localized approach in identification of potential CUI failure risk. This framework provides different PoF values for different areas within a piping line analyzed ranging from 0 to 1. A sample analysis for one piping line isometrics yields predicted PoF values ranging from 0.0003 to 0.5630 for piping configuration across the entire piping lines with multiple conditions in the CUI contributing factors. The results provide a guideline for plant owners to optimize CUI maintenance planning by prioritizing areas with higher PoF values, indicating higher risk.

1. Introduction

In process industries, insulated piping and equipment are always exposed to CUI, which is known as a major degradation mechanism in the form of localized corrosion affecting the external surface of the insulated components [1], [2]. CUI is mainly driven by moisture ingress into the insulation layer and other several factors including operating temperature, insulation type used, insulation conditions, painting quality, system design, environmental conditions where equipment is located, etc. [3], [4], [5]. N. Burhani et.al in [6], [7] stated that operating temperature is one of the significant factors that contributes to the worsening of CUI.

The hidden nature of CUI occurrence makes it difficult to be detected at early stage, making it a continuous global issue within the petrochemical and refineries industries [8], [9]. CUI remains to be a critical hazard where most cases are only detected at a later stage which in worst cases damage caused may lead to catastrophic failure triggering unplanned shutdown of plant, economic, safety and environmental issues [10], [11], [12]. A statistic documented by an oil and gas company relates to the economic impact of CUI stated that approximately 40%-60%

of expenditures are being spent on piping maintenance related to CUI cases [13], [14]. A leak from a 4 in. hydrocarbon line in an aging petrochemical plant located in the USA back in the year 2006 had caused a total loss of US$ 50 million to the company where 50% of unit being destroyed from the impact of massive fire caused by the leakage [15]

There are several inspection technologies available and number of studies on prediction methods for CUI have been conducted by researchers over the years. S. Lenka in 2016 discussed the working principles, advantages and disadvantages of inspection technologies available including ultrasonic thickness measurement, real time radiography, Neuron Backscatter, profile radiography, infrared, etc [16]. A review on few prediction methods for CUI studies done by Burhani et.al in July 2014 highlighted concern on the possibility for enhancement on the reliability of most model developed. The author suggested that consideration of CUI contributing factors like environmental conditions and operating temperature could further enhance the reliability of a model developed since most model developed are based on local industrial conditions which may not be universally applicable to plants at different locations with different environmental conditions [17].

On the industrial side and practices to address CUI assessment, detection and mitigation actions, several industrial guidelines and international standards or recommended practices are developed. The Committee Industrial Insulation (CINI) manual is a comprehensive reference for understanding and managing CUI risk. The manual explains insulation system design, material selection, cladding practices in preventing moisture ingress, effect of insulation aging toward corrosion development besides providing recommendations on weather protection and sealing configurations [18]. Det Norske Veritas Germanischer Lloyd recommended practice (DNVGL RP G109) published in December 2019 provides methodology in managing CUI threat in risk based, safe and cost-efficient manner. DNVGL RP G109 addressed the threat of CUI via PoF and consequence of failure (CoF) assessment. The PoF assessment is a qualitative assessment assessing four CUI barriers named material barrier, coating barrier, water wetting barrier and design barrier which are then combined as one total PoF [19].

Petronas Technical Guideline (PTG) 15.04.02 addresses CUI risk by a qualitative assessment incorporating 13 assessment criteria in determining the severity classification. The severity classification known as PoF is then mapped into the Petronas risk-based inspection (PRBI) risk matrix together with the CoF category for the CUI severity assessment [20]. The current technologies and industrial practices in mitigating CUI under thermal insulation and fireproofing materials by system approach is documented in [21]. The standard practice covers several sections for the control of corrosion under thermal insulation and fireproofing materials inclusive of mechanical design, protective coatings, corrosion mechanisms, insulation materials, inspection and maintenance.

American Petroleum Institute (API) recommended practice 583 provides guidelines in understanding CUI which covers several non-destructive evaluation (NDE) techniques available for CUI detection during inspection window, design consideration in minimizing CUI risk and best practices in CUI maintenance and mitigation [22]. API 583 also stipulates examples of information needed in development of CUI damage likelihood assessment. The API 581 on the other hand outlines a semi-quantitative RBI methodology in assessing the CUI PoF which considers multiple CUI damage contributors. The RBI methodology of PoF guidelines considers multiple factors including the years of piping been exposed to potential CUI risk, environmental condition, operating temperature, insulation type, insulation condition, coating quality, piping complexity, history of inspection, level of inspection effectiveness, etc [23]. However, in the guideline provided, there are unclear conditions in some parameter description like defining complexity where the criteria description on number of protrusions uses description like some and many which is subjective in definition. Hence, this study proposes a framework of the CUI PoF in accordance with the API 581 guideline by minimizing the uncertainties of parameters classification by introducing a localized assessment point based on the piping configuration across the entire piping line.

2. Methodology

Fig. 1 illustrates the overall methodology for the CUI PoF prediction framework proposed in accordance with API 581. Total 8 steps involved in the CUI PoF prediction which takes into consideration 15 CUI contributing factors inclusive of inspection history, inspection effectiveness, coating quality, coating age, pipe in service age, potential of pipe being expose to CUI risk, service temperature, environmental driver, insulation type and quality, complexity of piping component, pipe nominal thickness, pipe minimum required thickness, weldment joint and management system factor.

First step in prediction of the CUI PoF starts with location assignment based on isometric drawings received. This proposed framework assigned a focused and localized point throughout the entire isometric drawing based on piping configuration that considers the piping component and its complexity. In this case if the isometric pathway starts from a straight pipe to a reducer continues to straight pipe and directs to an elbow or tee, for each different component, a specific reference is assigned as location. For example stated, the location will be assigned as P1 (first straight pipe) followed by R1 (reducer), P2 (second straight pipe) and E1 (elbow) or T1(tee). Each location assignment process will start from the initial point where the isometric starts flowing.

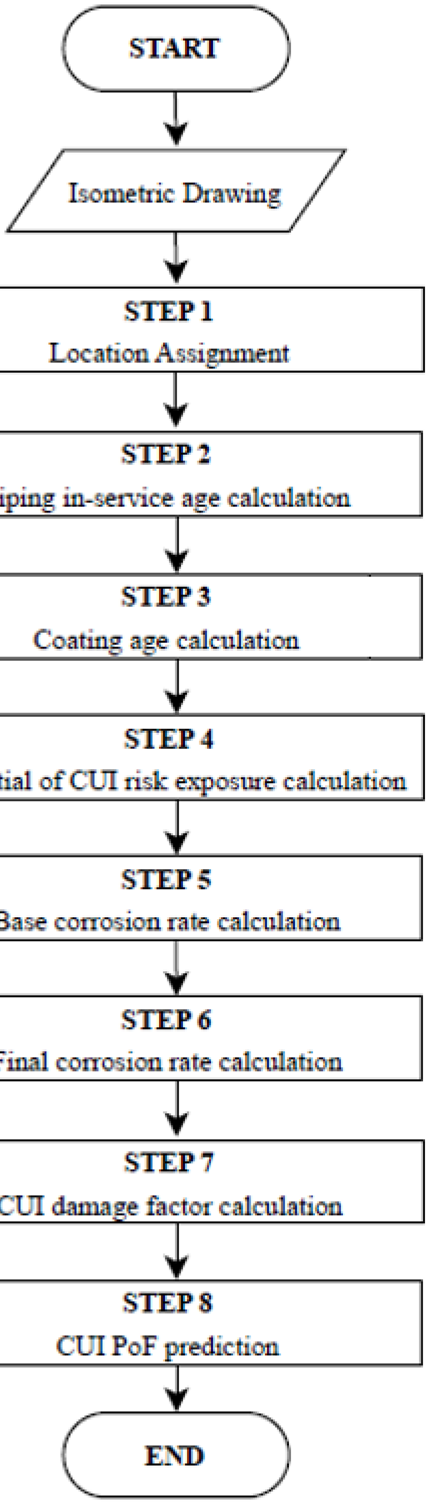

Fig. 1 *Overall methodology for CUI PoF prediction framework in accordance with API 581*

Next step after the location assignment is the piping in service age (age_{tk}) calculation. This step requires the inspection history record where the parameter of the latest inspection date is required. Piping in service age calculation calculated from date of analysis to the last inspection date as represented in equation (1) from [23] below:

$$age_{tk} = Analysis\ date - latest\ inspection\ date \tag{1}$$

The third step is to calculate the coating age (age_{coat}) in which this parameter is used to determine the time since coating of the pipe has been determined to be ineffective. This step requires a subroutine where coating quality is assigned based on characteristics described in [23]. Subroutine for the age_{coat} calculation refers to adjustment of coating date based on coating quality as shown in Fig. 2.

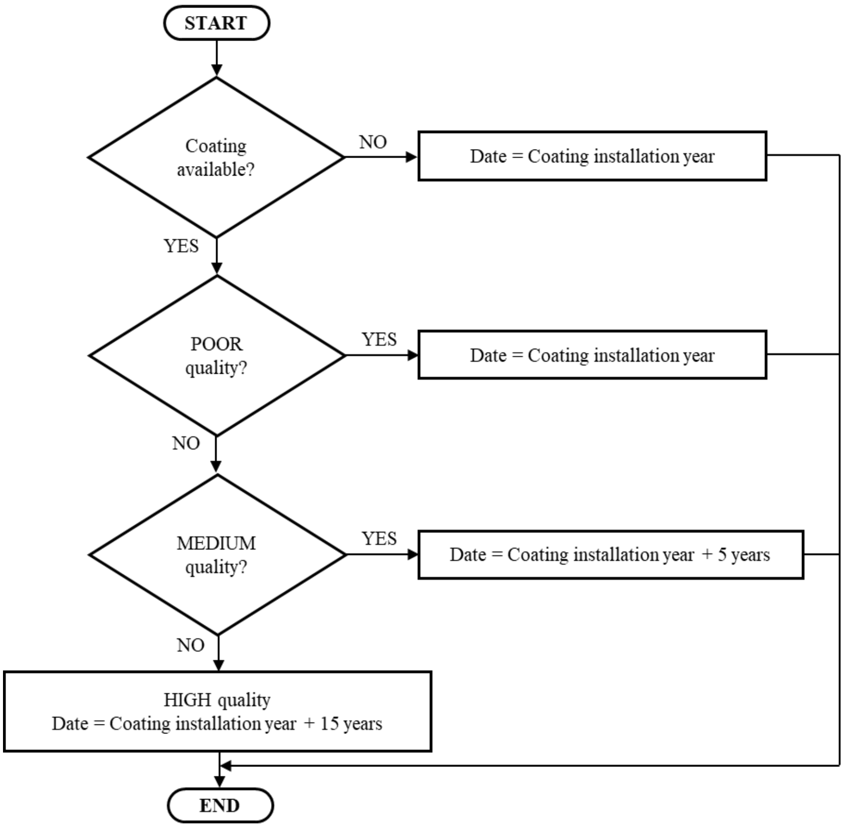

Fig. 2 *Flowchart for coating installation date adjustment*

Equation (2) from [23] is applied in the process of age_{coat} as shown:

$$age_{coat} = max[0, (Analysis\ date - date)] \tag{2}$$

Step number 4 in the CUI PoF prediction framework is the calculation for potential of CUI risk exposure that the pipe has been facing. The formula used is shown in equation (3) extracted from [23] where the minimum time between pipe in service age and coating age will be considered as the potential of CUI risk exposure.

$$age = \min[age_{tk}\ , age_{coat}] \tag{3}$$

Next is the fifth step where the base corrosion rate is to be calculated. For this step, 2 inputs are required, which are the piping line service temperature and the environmental driver which determines the location of the plant and piping line. API 581 outlines 4 different environmental drivers with specific reference to corrosion rate table for the base corrosion rate calculation. The 4 environmental drivers are severe, moderate, mild and dry. The classification of drivers is based on the rainfall count, corrosive condition of the atmosphere where the piping line is located and the atmospheric chloride content. Details of the description can be found in [24] part 2, section 15.6.2. Table 16.2M in [24] is used as reference for the base corrosion rate calculation where linear interpolation is applied to interpolate the base corrosion rate for specific intermediate service temperature values. The linear interpolation equation used is as in equation (4) from [25]:

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$$y = y_1 + \left(\frac{x - x_1}{x_2 - x_1}\right) \times (y_2 - y_1) \quad (4)$$

Where:

- y: interpolated corrosion rate
- x: operating temperature at which corrosion rate is to be interpolated
- x_n: coordinates of known operating temperature n
- y_n: coordinated of know corrosion rate n

Step 6 in the CUI PoF prediction framework is to calculate the final corrosion rate. In this step, there is an adjustment made where weldment joint is introduced in the equation as one of adjustment factors. There are 5 adjustment factors being considered in the final corrosion rate calculation. These factors are the complexity of the piping component, the insulation type used, the insulation condition, existence of pipe support at the piping area and existence of weldment joint. The complexity of piping component and insulation condition factors are categorized into 3 classifications; above average, average and below average with specific description and weightage value. Weightage for insulation type used can be referred to in [24] Table 16.3. Equation (5) shows the equation used to calculate the final corrosion rate:

$$final\ corrosion\ rate = base\ corrosion\ rate\ \times F_{INS} \times F_{CM} \times F_{IC} \times max[F_{PS}, F_W] \quad (5)$$

Where:

- F_{INS}: adjustment factor for insulation type
- F_{CM}: adjustment factor for complexity
- F_{IC}: adjustment factor for insulation condition
- F_{PS}: adjustment factor for pipe support
- F_W: adjustment factor for weldment joint

The CUI damage factor calculation in step 7 requires 3 inputs which are the damage factor parameter (A_{rt}) calculated using equation from [23], inspection history indicating number of inspections done and the level of inspection effectiveness performed. Detail description of the inspection effectiveness level can be found in [24] under part 2 annex C table 2.C.10.1. These inputs are used to determine the CUI damage factor by mapping into the table provided in [23] where interpolation method is applied for any intermediate conditions. Equation used for the A_{rt} calculation is as follows:

$$A_{rt} = max\left[\left(1 - \frac{t_{rd} - C_r \cdot age}{t_{min} + CA}\right), 0.0\right] \quad (6)$$

Where:

- C_r: final corrosion rate
- t_{min}: minimum required thickness
- CA: corrosion allowance

The final step to predict the CUI PoF is by multiplying generic failure frequency (*gff*), management system adjustment score (F_{MS}) and the CUI damage factor calculated in step 7. The management system adjustment score is basically obtained from the plant owner through survey of elements that accounts for the influence of plant's management system on the mechanical integrity of the plant's equipment. The equation used for this calculation is based on [24] and shown in equation (7) below:

$$P_f(t) = gff \cdot F_{MS} \cdot D_f(t) \quad (7)$$

Where:

- $D_f(t)$: CUI damage factor calculated in step 7

3. Results and Discussion

Fig. 3 and Fig. 4 show the first and second isometric drawings for the piping line used in this study's analysis. The dotted green dots across both isometric drawings shown are the focused and localized analysis locations assigned based on the piping configuration considering its orientation (horizontal and vertical) and components like elbow, tee, pipe support etc. The labels on each location shown in both Fig. 3 and Fig. 4 represent each piping component where P represents for pipe, PS for pipe support, F for flange, E for elbow, A for accessories and V for valve.

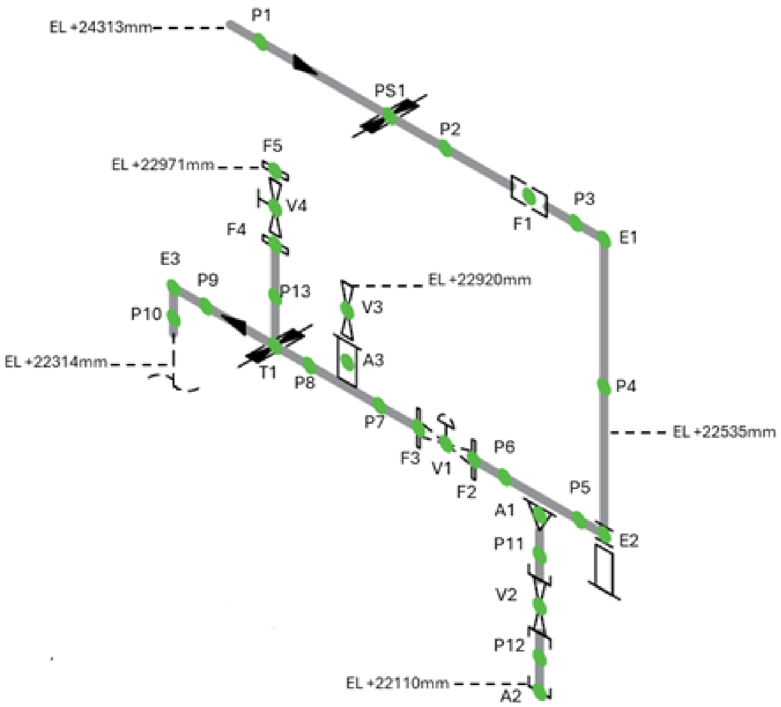

Fig. 3 *First isometric drawing of the piping line with location of analysis assigned*

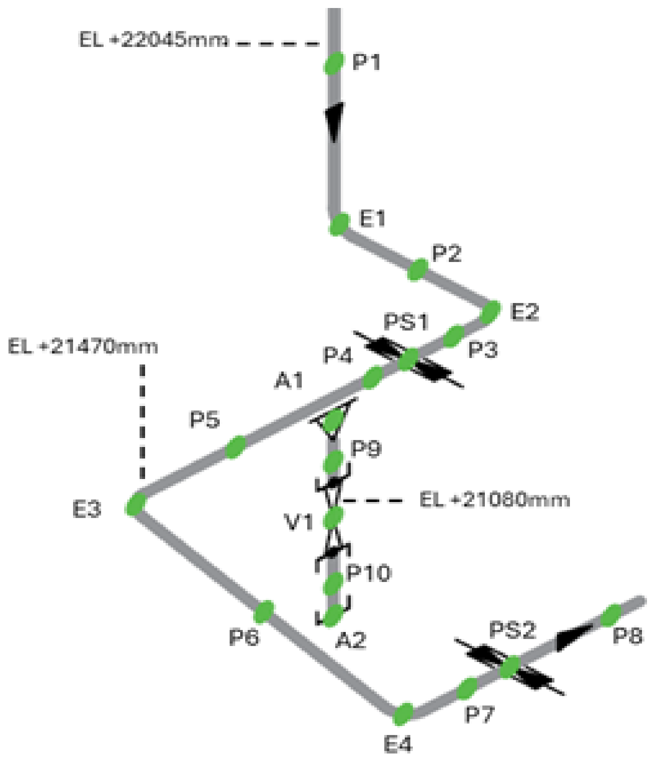

Fig. 4 *Second isometric drawing of the piping line with location of analysis assigned*

Table 1 and Table 2 respectively summarize the inspection history, latest inspection year, pipe nominal thickness and PoF values predicted using the proposed framework for each localized analysis location across both isometric drawings for the piping line. Results show unique PoF values are predicted for each localized location assigned for analysis using the framework proposed.

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Table 1 *Summary of inspection history, latest inspection year, pipe nominal thickness and predicted PoF values for all locations analyzed within first isometric drawing of piping line*

Location	Inspection History	Latest Inspection Year	Pipe Nominal Thickness (mm)	Predicted PoF
P1	No	1995	7.11	0.0017
PS1	No	1995	7.11	0.1461
P2	No	1995	7.11	0.0017
F1	Yes	2016	7.11	0.0029
P3	No	1995	7.11	0.0017
E1	No	1995	7.11	0.1461
P4	No	1995	7.11	0.0003
E2	Yes	2016	7.11	0.0029
P5	No	1995	7.11	0.0003
P6	No	1995	7.11	0.0003
F2	Yes	2016	7.11	0.0003
V1	Yes	2016	7.11	0.0029
F3	Yes	2016	7.11	0.0003
P7	No	1995	7.11	0.0003
P8	No	1995	7.11	0.0003
T1	No	1995	7.11	0.1461
P9	No	1995	7.11	0.0003
E3	Yes	2016	7.11	0.0029
P10	Yes	2016	7.11	0.0003
A1	Yes	2016	5.56	0.3213
P11	Yes	2016	5.56	0.2246
V2	Yes	2016	5.56	0.3213
P12	Yes	2016	5.56	0.1972
A2	Yes	2016	5.56	0.3213
A3	Yes	2016	5.56	0.5630
V3	Yes	2016	5.56	0.3213
P13	Yes	2016	5.49	0.0326
F4	Yes	2016	5.49	0.0326
V4	Yes	2016	5.49	0.0326
F5	Yes	2016	5.49	0.0326

Table 2 *Summary of inspection history, latest inspection year, pipe nominal thickness and predicted PoF values for all locations analyzed within second isometric drawing of piping line*

Location	Inspection History	Latest Inspection Year	Pipe Nominal Thickness (mm)	Predicted PoF
P1	No	1995	7.1100	0.0003
E1	No	1995	7.1100	0.1461
P2	No	1995	7.1100	0.0003
E2	No	1995	7.1100	0.1461
P3	No	1995	7.1100	0.0003
PS1	No	1995	7.1100	0.1461
P4	No	1995	7.1100	0.0003
P5	No	1995	7.1100	0.0003
E3	No	1995	7.1100	0.1461
P6	No	1995	7.1100	0.0003
E4	No	1995	7.1100	0.1461
P7	No	1995	7.1100	0.0003
PS2	No	1995	7.1100	0.1461
P8	No	1995	7.1100	0.0003
A1	Yes	2016	5.5600	0.3213
P9	Yes	2016	5.5600	0.1972
V1	Yes	2016	5.5600	0.3213
P10	Yes	2016	5.5600	0.1972
A2	Yes	2016	5.5600	0.3213

Tabulation of the unique PoF values predicted for each analysis location assigned across both isometrics of the piping line are illustrated via the bar charts shown in Fig. 5 and Fig. 6 respectively. Fig. 5 shows the tabulation of predicted PoF values across localized analysis location in the first isometric of the piping line. The predicted PoF values varies from the range of 0.0003 to 0.5630. There are 9 different locations of analysis predicted with the same PoF values of 0.0003 which consists of 7 pipe locations and 2 flange locations. The total 9 locations are located at main branch of the piping line with nominal thickness of 7.11 mm as shown in Table 2. 3 out of 9 locations have inspection history in 2016. The locations are P10, F2 and F3. This explains the reason for the location of F2 and F3 even with higher complexity conditions compared to P10, ended with the same predicted PoF value.

The effects of inspection history and nominal thickness of the pipe towards predicted PoF value for same complexity level are demonstrated by the remaining 12 locations of pipe. The locations are P4, P5, P6, P7, P8 and P9 with PoF values of 0.0003, P1, P2 and P3 with PoF values of 0.0017, P13 with PoF values of 0.0326, P12 with PoF value of 0.1972 and P11 with PoF value of 0.2246. Referring to the summary in Table 2, P4, P5, P6, P7, P8 and P9 are pipe sections with nominal thickness of 7.11 mm with no inspection history. Meanwhile, P11 and P12 are pipe sections with nominal thickness of 5.56 mm and inspection history in 2016 with non-destructing test performed resulting in wall loss reading of 0.71 mm for P11 and 0 mm for P12. Hence, for P11 and P12 that have same nominal thickness and year of inspection, the predicted PoF values are higher for P11 compared to P12 due to the different condition of wall loss.

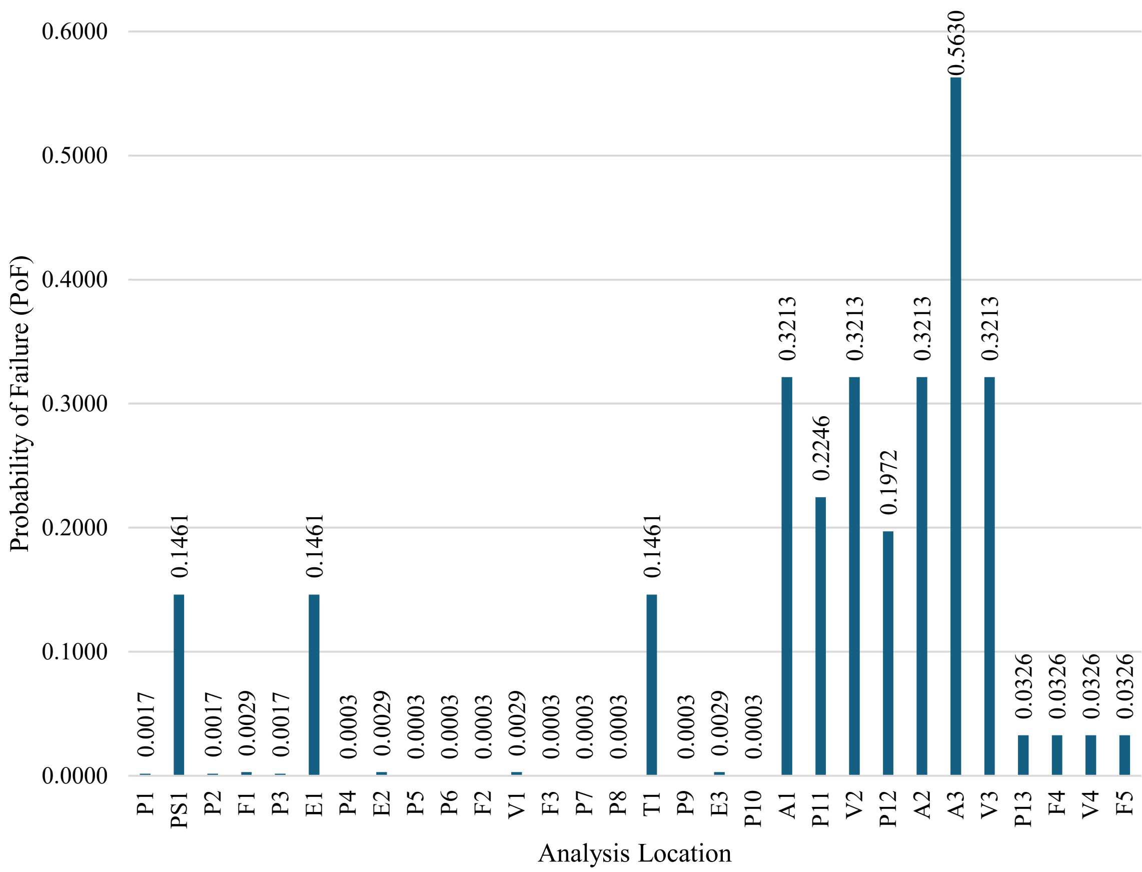

Fig. 5 *Plot of predicted PoF across analysis locations in first isometric of the piping line*

Fig. 6 shows the tabulation of predicted PoF values across 19 localized analysis locations in the second isometric of the piping line. The predicted PoF values varies from the range of 0.0003 to 0.3213. It can be seen from the plot in Fig. 6, all 8 pipe sections (P1, P2, P3, P4, P5, P6, P7 and P8) with same nominal thickness of 7.11 mm and inspection history record in this isometric drawing have the same predicted PoF values of 0.0003. Remaining two pipe sections, P9 and P10 with nominal thickness of 5.56 mm and inspected in 2016, yield the same predicted PoF values of 0.1972. This result proves that CUI is driven by many factors inclusive of pipe size and inspection history.

The entire elbow locations and pipe support locations across this isometric drawing have the same predicted PoF values of 0.1462 despite its different level of complexity. All the elbow and pipe support locations have the same record of inspection history, operating temperature and nominal thickness. On the other hand, two accessories (A1 and A2) and one valve, V1 with the same nominal thickness of 5.56 mm and record of inspection history with latest year of inspection in 2016 share the same PoF values of 0.3213. These results reflect the consideration of several factors in the CUI PoF prediction framework proposed in this study.

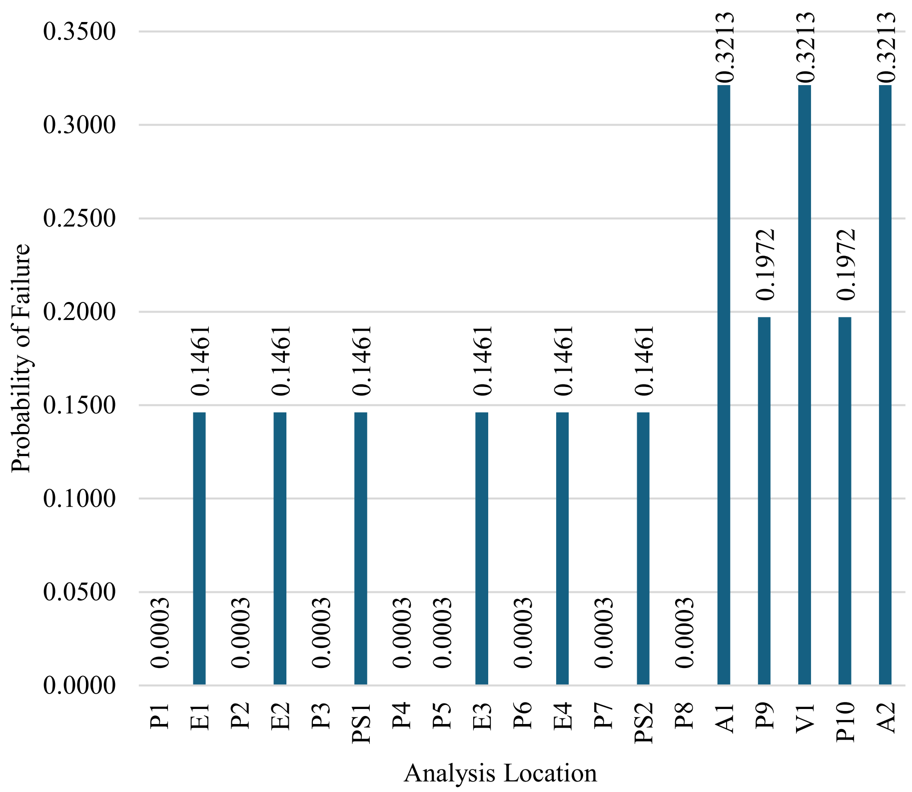

Fig. 6 *Plot of predicted PoF across analysis locations in second isometric of the piping line*

Tabulation of variation in predicted PoF values across same pipe component for pipe, elbow, flange and valve with different nominal thickness and inspection history within the entire piping line inclusive of both isometrics are illustrated in Fig. 7, Fig. 8, Fig. 9 and Fig. 10 respectively.

Fig. 7 shows the overall tabulation of predicted PoF values for pipe locations analyzed through the entire piping lines with range of 0.0003 to 0.2246. The difference between the predicted PoF values is mainly due to variance in the nominal thickness of the pipe section, inspection history and service temperature at specific locations which are taken into consideration in the prediction framework proposed.

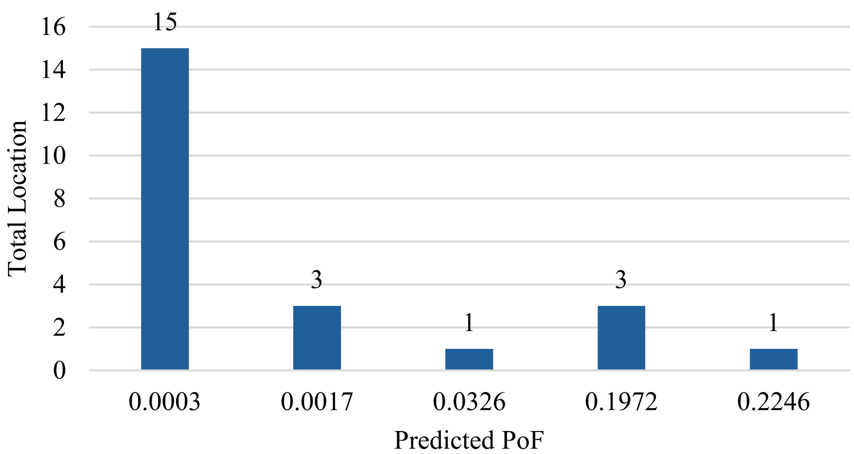

Fig. 7 *Plot of overall tabulation of predicted PoF for pipe locations across entire piping line*

Fig. 8 shows a variation between 0.0029 and 0.1461 for predicted PoF values of 7 elbow locations throughout the entire piping line involving both isometrics. The 2 elbow locations with predicted PoF value of 0.0029 have gone through inspection in 2016, hence reduced their CUI risk compared to the remaining 5 elbow locations

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without inspection history. This explains the significant difference of the predicted PoF value between all the 7 elbows analyzed via the proposed framework.

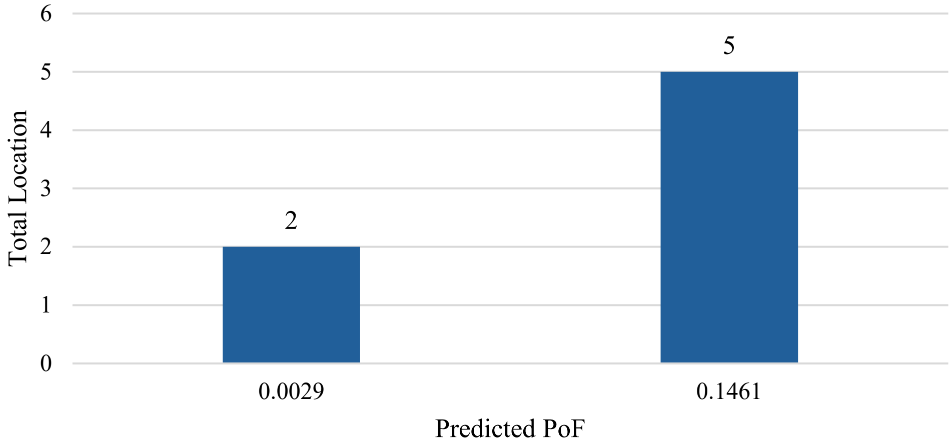

Fig. 8 *Plot of overall tabulation of predicted PoF for elbow locations across entire piping line*

A total of 5 locations at flange area are being analyzed using the proposed framework which yields the results of 2 locations with predicted PoF value of 0.0003, 1 location with 0.0029 and remaining 2 locations with 0.0326 as shown in Fig. 9. Variation of the predicted PoF values is due to the difference in the insulation conditions at each location. Insulation condition is one of the factors being considered in the CUI PoF prediction framework proposed in this study with each condition resulting in different weightage contributions to the final corrosion rate calculation that affects the final predicted PoF value as explained in methodology section of this paper.

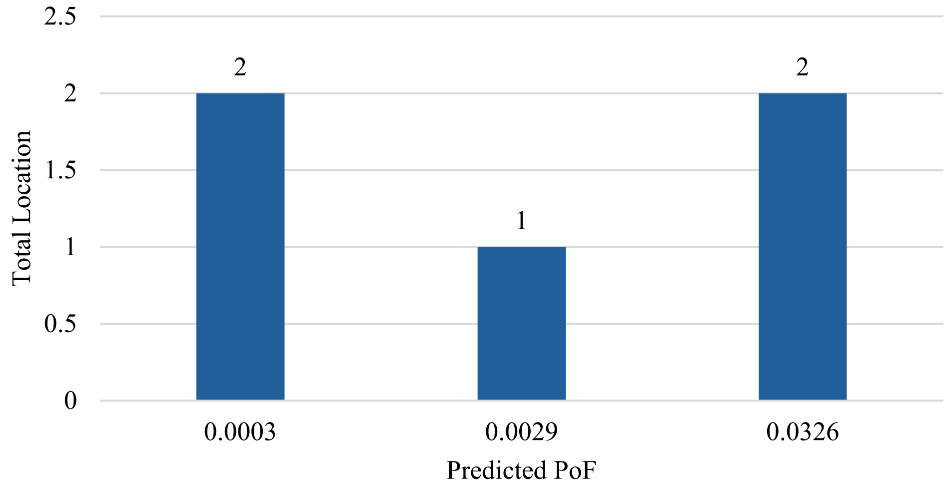

Fig. 9 *Plot of overall tabulation of predicted PoF for flange locations across entire piping line*

Fig. 10 shows the plot of overall predicted PoF tabulation for location near to valve. Results show 3 variations of predicted PoF values where 1 location predicted with 0.0029, 1 location with 0.0326 and remaining 3 locations with 0.3213. This is due to variation in the service temperature that drives different corrosion rate predictions that leads to difference in the predicted PoF values as explained earlier in the methodology section of this paper.

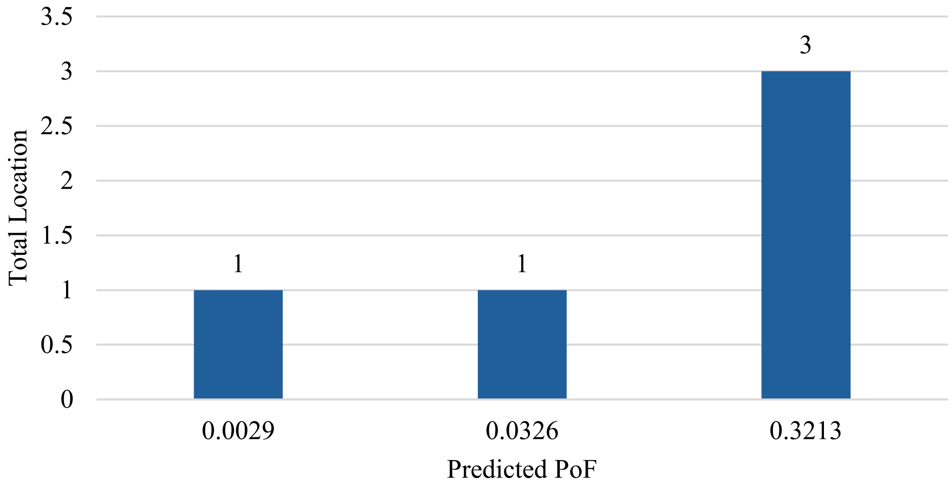

Fig. 10 *Plot of overall tabulation of predicted PoF for valve locations across entire piping line*

3. Conclusion

The proposed CUI PoF prediction framework in this paper is in accordance with the API 581 guidelines where multiple CUI contributing factors are being considered in the calculation. The factors considered in the CUI PoF prediction include inspection history, coating quality, insulation type, insulation condition, piping complexity, service temperature of piping lines, environmental factor etc. as per detail explanation in the methodology section. Improvement from the API 581 guidelines is on the weightage introduced for weldment joint in the final corrosion rate calculation and the localized and focused location for analysis that is based on the piping configuration. Enhancement on the localization of location for analysis is to provide option for prioritization of location to focus on CUI maintenance program in combatting CUI issues that are very challenging to cater due to the big volume despite its nature of occurrence that are hidden.

Based on the results obtained from an analysis carried out for a total of 49 locations across 1 piping lines using the proposed framework, variation of PoF values is being predicted. The variation is due to multiple factors considered and is useful in helping plant owners to prioritize area for maintenance scoping in a more objective way. Plant owners can use the predicted PoF value by prioritizing areas with higher PoF values since the higher PoF value indicates the higher CUI risk. The proposed framework indirectly helps to screen out locations that have been inspected and focus locations that acquire attention to ensure more volume of inspection coverage since it is a time base analysis with time element parameters like coating age and pipe in service age. Hence, this can aid in reducing potential risk of inattention location that may cause severe CUI that leads to catastrophic failure.

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Conflict of Interest

The authors declare that there is no conflict of interest regarding the publication of the paper.

Author Contribution

The authors confirm contribution to the paper as follows: ***study conception and design:*** *S.F. Yeow, A.R. Othman;* ***data collection:*** *S.F. Yeow, A.R. Othman, Fauziah Mat;* ***analysis and interpretation of results:*** *S.F. Yeow, A.R. Othman, M, Mohammad;* ***draft manuscript preparation:*** *S.F. Yeow, A.R. Othman, Fauziah Mat, M. Mohammad. All authors reviewed the results and approved the final version of the manuscript.*

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