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TOP OF THE LINE CORROSION – COMPARISON OF MODEL PREDICTIONS WITH FIELD DATA

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ABSTRACT

Top of the Line Corrosion (TLC) is a serious concern for the oil and gas industry and has been the cause of numerous pipeline failures. Many research projects have been developed in order to better understand the mechanisms and to develop accurate predictive tools for TLC. The corrosion mechanisms implemented in most of the available TLC prediction models are mostly based on laboratory based experimental data. Therefore, it is essential to validate the model's capabilities by using field data.

A new approach in comparing model predictions with field data is proposed in this work. Information collected from a sweet field having experienced TLC issues was analyzed processed and then used as an input for the TLC predictive model to simulate the evolution of temperature, pressure, water condensation rates (WCR) and TLC rate along the pipeline. The simulation results were then compared with in-line inspection (ILI) data. Challenges encountered in the analysis of the information about the field conditions (inaccuracy and variability of production data) as well as the ILI data are discussed and a coherent methodology for comparison with simulation results is proposed.

Keywords: *Top of the line corrosion modeling, field data, magnetic flux leakage (MFL) data*

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INTRODUCTION

Top of the line corrosion (TLC) in dewing condition has been identified as the cause of numerous pipeline failures and, consequently, has become a growing concern for the oil and gas industry. TLC is a phenomenon encountered under condensation conditions in wet gas pipelines, operated in the stratified flow regime at low gas velocity. Water will condense on the top of the pipeline surface due to the temperature difference between the external and internal pipeline environment. Corrosive agents, such as carbon dioxide (CO_2), hydrogen sulfide (H_2S) and volatile organic acids will rapidly dissolve into this condensate. TLC was the focus of many research projects aimed to better understand the corrosion mechanism and at developing successful mitigation techniques. Corrosion prediction models were developed and used to provide an overall assessment of the severity of the corrosive conditions. However, the corrosion mechanisms implemented in the model are mostly based on laboratory experimental data. Consequently, it is necessary to evaluate model performance when applied to field experiences involving actual pipeline TLC failures.

In 2010, Gunaltun *et al*. presented a process for comparing TLC prediction model with a field data; however, the comparison was performed by using incomplete field data.[1] As a result, there are a few gaps in understanding and difficulties in interpreting the results. Therefore, a different methodology is proposed here in order to validate a TLC model by using field data. In the present work, the TLC model TOPCORP[(1)] (referred to as the “model” in the following text) developed by the Institute of Corrosion and Multiphase Technology, Ohio University, was used and its capabilities were validated against subsea line data from an offshore gas field in the Gulf of Thailand which is in operation since 1992.

A TOP OF THE LINE PREDICTION MODEL

The TLC model used in the current study was developed by Zhang *et al*. This model represents the first attempt to provide fully mechanistic TLC predictions.[2] The three major processes in TLC covered by the mechanistic model are:

- Dropwise condensation, used for condensation rate calculation based on heat and mass transfer theory.
- Chemistry of the condensed water, developed from thermodynamic arguments by using chemical equilibria.
- Corrosion, where the TLC rate was predicted based on the kinetics of the electrochemical reactions.

The effect of many important factors such as gas temperature, CO_2 partial pressure, gas velocity, condensation rate and acetic acid concentration on TLC were accounted for in the model.[2] However, the effect of oil/water co-condensation was not taken into account to date, as the research on this topic is still ongoing. The reader is invited to consult Zhang’s *et al.* original publication for a full description on the model.[2]

[(1)] Trade name

A METHODOLOGY FOR COMPARING MODEL PREDICTIONS WITH FIELD DATA

There are many challenges one has to overcome in the attempt of direct comparison between ILI data and model predictions. The problems can be divided into three main groups as follows:

Issues related to the accuracy of field Information

- Availability, completeness and accuracy of production data.
- Significant variations over time in production data.
- Availability of updated topographic data.

The model is rather sensitive to variations of input conditions, such as production rates, temperature, pressure, etc., which are common in a field situation. The level of uncertainty and inaccuracy related to these data can be significant and represents a definite challenge in the analysis. In addition, the topography, which includes pipeline burial information, is essential for calculation of the condensation rate and TLC corrosion evaluation.

Issues related to interpretation of the model predictions

- Which model predictions should be compared with the ILI data?
- How to incorporate variations in production data over time into the prediction?
- How to reflect the change in the conditions and the TLC rate along the pipeline in the model?

Even though the model has been developed to predict transient corrosion, it suggests that a uniform steady state TLC rate is typically obtained in a matter of weeks or months. Due to the much longer time periods between ILI conducted for these lines, it is most appropriate that the steady state corrosion rates are compared to the time-average wall thickness loss data obtained from ILI inspections. To do this, a thorough analysis of the production data needs to be conducted with the identification of weighted time averages for the key parameters over different time periods. In addition, the model can easily perform calculations which can determine the severity of TLC along the pipeline by accounting for the change of operational parameters and by identifying areas of low and high water condensation.

Issues related to the analysis of ILI data

- How to take into account the inherent inaccuracy of TLC feature sizing?
- Should the size or spatial distribution of the TLC features be considered in addition to the maximum depth of attack?
- What is the best approach to compare model predictions with the complex ILI data?

The performance of MFL data is strongly affected by velocity of the tool, magnetization values and presence pipe joints. Consequently, the data obtained by ILI need to be filtered in order to identify those data which are most accurate and would be best comparable to the model predictions.

The Procedure

The outline of procedure for the comparison between the model prediction and ILI data is presented in Figure 1.

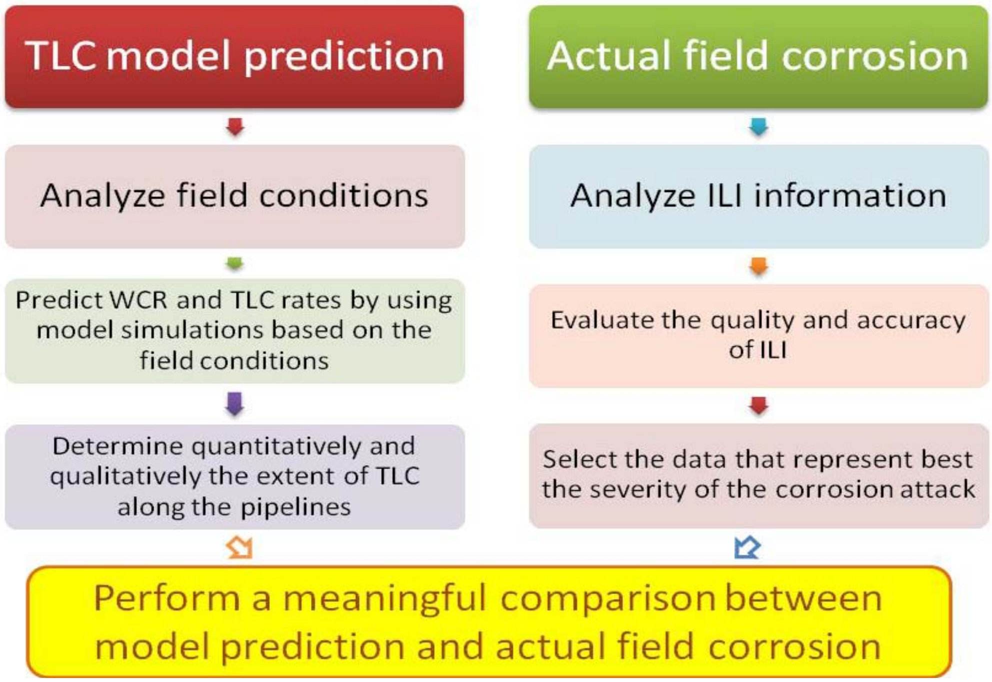

Figure 1: Procedure for comparison of model predictions with the field data.

Field condition analysis

The following procedure was implemented to effectively analyze the field data:

- Step 1: The evolution of the operating parameters for a selected line from the start-up to present is divided into a number of time periods where these parameters had relatively stable values. For each of these time periods, a time averaged value is calculated for each operating parameter.
- Step 2: So-determined values for these parameters are used to calculate water condensation rates and temperature profiles using a heat and mass transfer line model.
- Step 3: The simulations are then run in order to obtain TLC rate predictions for a number of selected points along the pipeline. The simulations are executed until a steady state corrosion rate is obtained.
- Step 4: Cumulative wall thickness (WT) loss is calculated for each time period; they are then added and compared with provided MFL data.

In-Line Inspection Data Analysis

Magnetic Flux Leakage (MFL) is a key technique for detection of wall thickness changes in pipeline transmission systems. The basic principle of the MFL is that the features on the pipe steel surface can be detected through the magnetization of the metal. Distortions (or so called "leaks") in the magnetic flux signal are indications of the presence of internal or external features present on the steel surface. It is crucial to understand that the MFL tool does not directly measure the wall thickness loss. Deviations in magnetic flux are translated into features on the metal surface by using proprietary algorithms. These algorithms are often different for each vendor/client, and also vary across different tools. In addition, the algorithms are continuously updated and calibrated. As a result not all ILI data are of the same accuracy/quality. Consequently, one needs to be cautious when analyzing ILI data and consider only the most accurate and representative ILI data before comparing them with the model simulation. The following procedure is implemented in the current approach:

- Only the first few kilometers of a pipeline were considered in this study, since it is the section where the most severe TLC is typically encountered.
- Corrosion features in the vertical riser were not included in the analysis because they cannot be categorized as TLC.
- Only features in the upper section of the pipe (between 9 and 3 o'clock) were analyzed.
- ILI data obtained for features close to weld joints are known to be notoriously noisy and consequently unrepresentative. Joints were present every 12 meters along the line and therefore the features located ±0.5 meter around the weld joints were eliminated from the analysis.
- As the model has been developed to predict the most severe TLC rate, the set of data points along the line representing the maximum wall thickness loss was retained for comparison with the simulations. This set is referred to as the "maximum penetration envelope".
- Another feature of the model is that it predicts uniform TLC (as opposed to localized attack), therefore an effort has been made to separate out the ILI data representative of uniform attack. This was achieved by eliminating the small size isolated features which did not appear in the so called "clusters". Clusters were defined as large corrosion features (where width and depth was at least 3 times the wall thickness), following the classifications developed by the Pipeline Operators Forum (POF).[3]

COMPARISON OF MODEL PREDICTIONS WITH FIELD DATA

Part I: Detailed analysis of Line A

Field conditions

Field A is an offshore gas field in the Gulf of Thailand in operation since 1992. Subsea lines in this field have been subjected to TLC since production start-up, due to a highly corrosive environment. The produced gas contains 23% of CO_2 on average. The fluid temperature in the lines is typically higher than 80°C. With the low external environmental temperature (26°C on average), the temperature difference between the internal and external pipeline environment is quite high leading to high condensation rate and consequently severe TLC.

The general characteristics of Line A are presented in Table 1. The pipeline configuration is affected by changing seabed levels and soil burial depths. The fluctuations in pipeline inclination also affect predicted flow regimes, which show non-stratified flow in some sections.
Figure 2 shows the production variation for Line A from the start-up year (1998) to the inspection year (2005). The production data were analyzed and separated into three time periods. The average values for each time period were calculated and presented in Figure 3. These averaged values were used as inputs for the TLC model to predict the severity of TLC attack for each time period.

Table 1
Line A characteristics

Pipe characteristic	Line A
Pipe length (km)	7.1
Internal diameter (m)	0.34
Pipe wall thickness (mm)	15.9
Insulation type	3LPP*
Insulation Conductivity (W/mK)	0.22
Insulation Thickness (mm)	2
Outside (sea water) temperature (^oC)	26

* Three Layer Polypropylene Coating

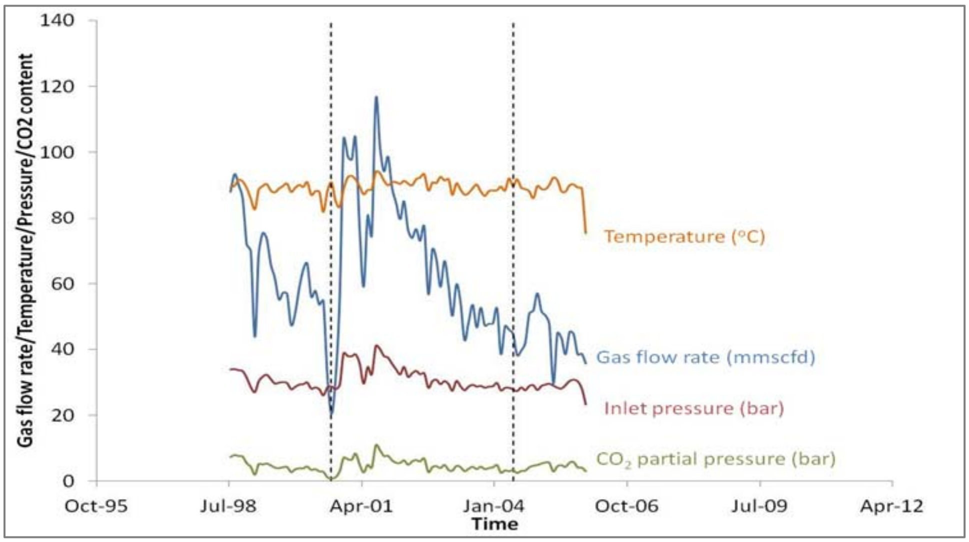

Figure 2: Input parameter variation over time for Line A.

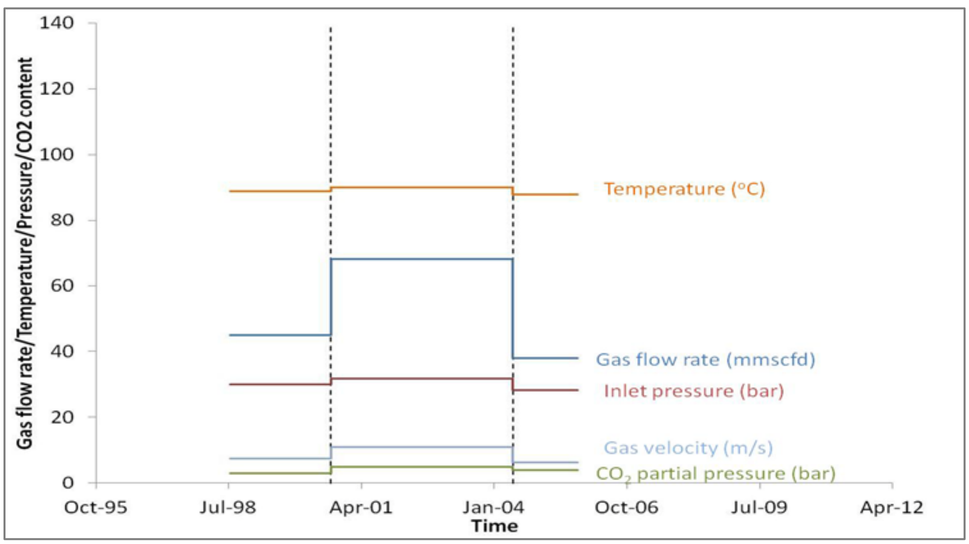

Figure 3: Averaged input parameters for Line A using three time periods.

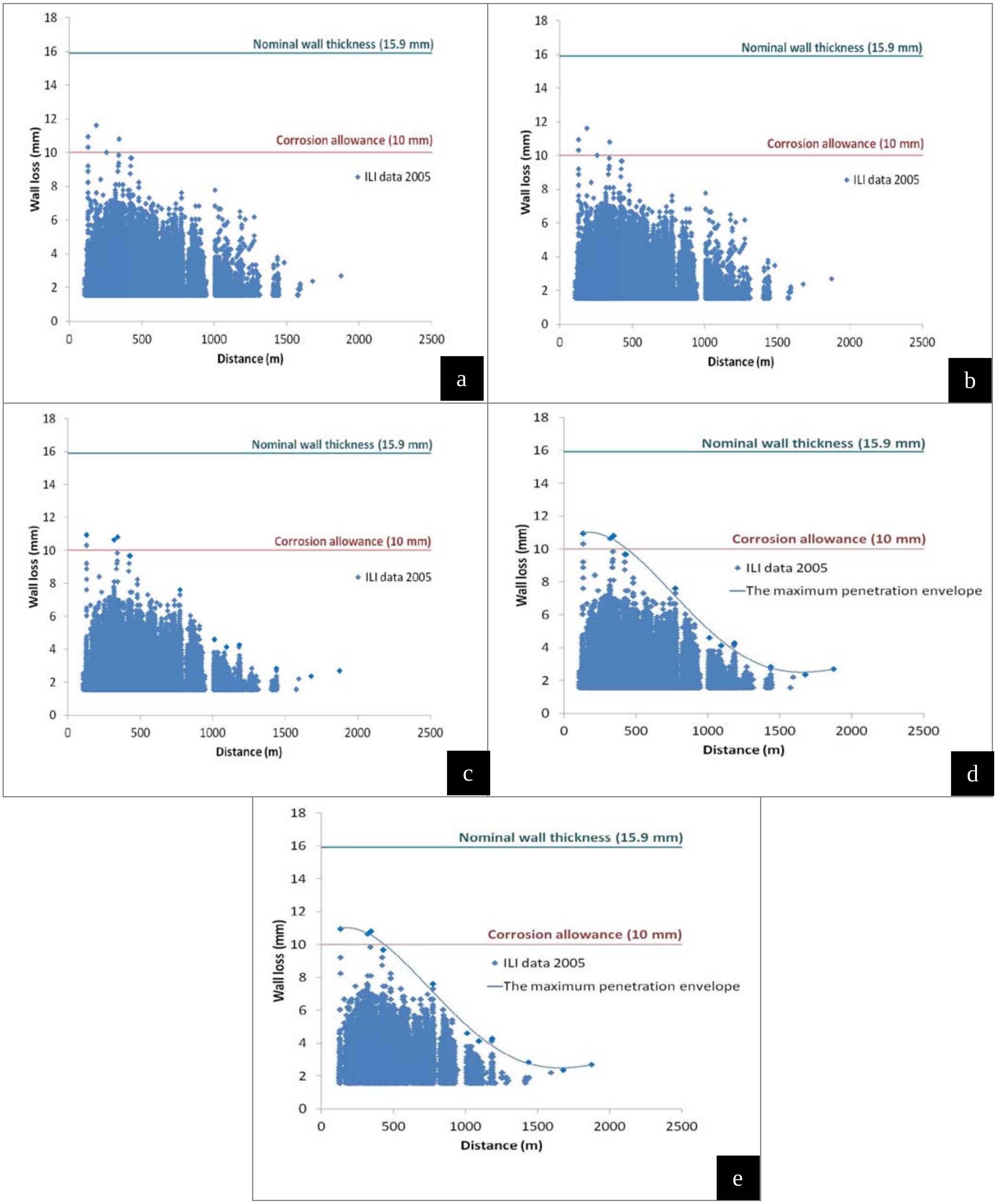

Figure 4: ILI data filtering for Line A: a) all ILI corrosion features, b) a subset containing only TLC features (other corrosion features filtered out), c) a further subset with the noisy measurement close to pipe joints filtered out, d) another subset showing the maximum penetration envelope, e) a final subset showing only TLC clusters (uniform corrosion data) along with the maximum penetration envelope.

In-line inspection analysis

Following the procedure above, representative ILI data from Line A were filtered and illustrated in Figure 4. Those features were used to compare with the TLC model predictions results. For Line A, the maximum wall thickness loss was captured by the maximum penetration envelope shown in Figure 4d and Figure 4e. The uniform TLC features identified as clusters are shown in Figure 4e. In this case they coincide with the maximum penetration envelope. Therefore in the case of Line A we can conclude that the TLC attack was predominantly uniform.

Simulation results

Figure 5 shows predicted WCR and temperature profile along the line obtained by the heat and mass transfer analysis. The analysis was broken up into three time periods (time period#1, period#2 and period#3) when it was found that the operating parameters were reasonably stable – so that time-averages could be used. The majority of predicted flow regimes for Line A were stratified flow regime indicating a TLC possibility.

For the time period#1, high values of WCR were calculated at the beginning of the pipeline due to the steeper temperature difference between the inside and outside of the pipe wall. As expected, the values of WCR decreased along the pipeline because of the reduction of internal fluid temperature. For the time period#2, the values of WCR were higher than in the time period#1 at the same locations; however, at other locations the increase in gas velocity affected the change in flow regime to non-stratified eliminating the risk from TLC. For the time period#3, predicted WCR is much lower than in the first two time periods due to the decreased internal fluid temperature and lower heat exchange between the pipeline fluids and environment.

Figure 6 shows the predicted TLC rate. High severity of TLC was predicted for the time period#2. Cumulative wall thickness loss data are presented in Figure 7 indicating a high overall risk for TLC in this pipeline.

Comparison between the model prediction and field data

In Figure 8, the analyzed ILI data (including error bars equivalent to ±10% wall thickness stemming from instrument accuracy), are compared with the cumulative wall thickness loss predicted by the TLC model. The predicted TLC line is in good agreement with the maximum wall thickness loss ILI data (i.e. the maximum penetration envelope).

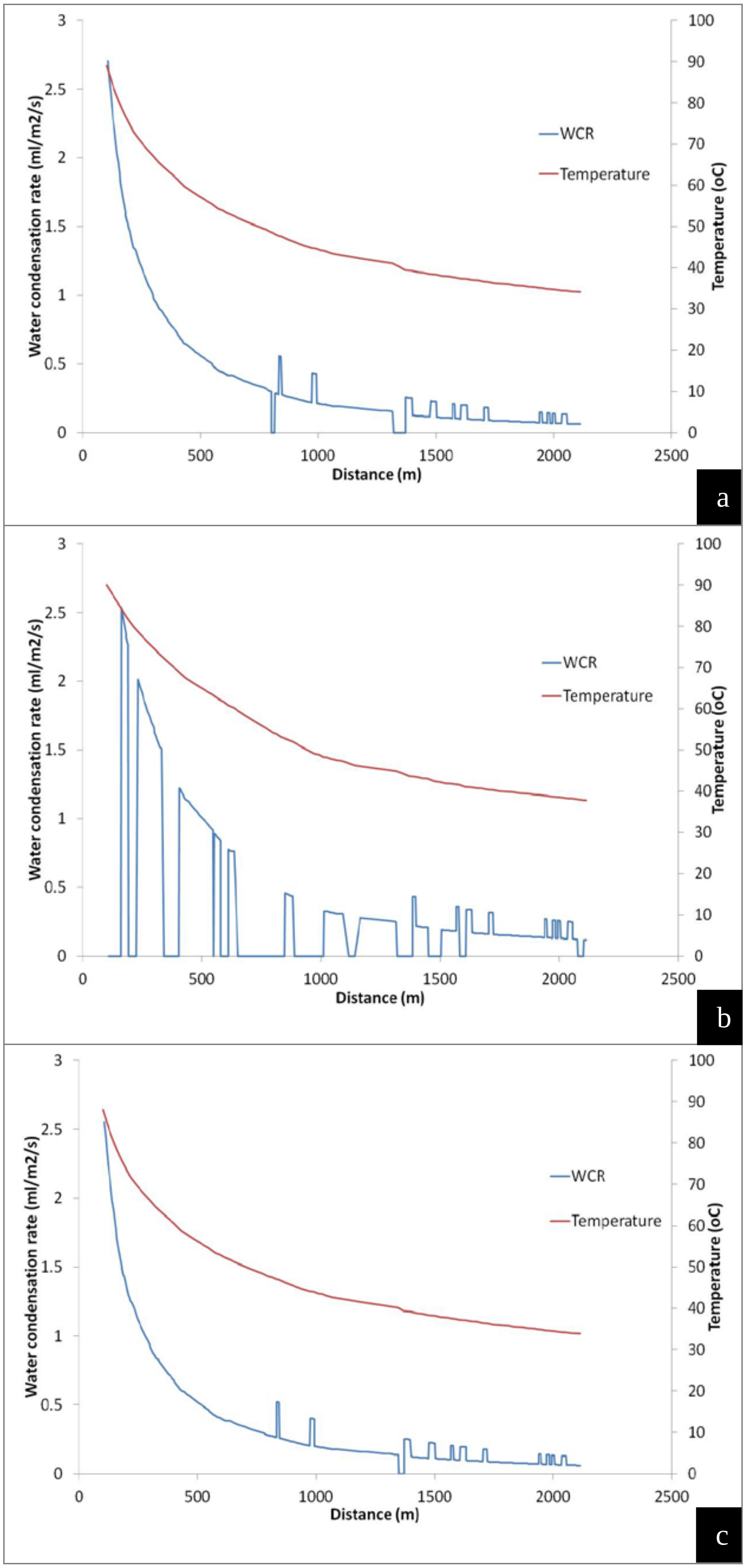

Figure 5: WCR and temperature profile along the length of the pipeline predicted from heat and mass transfer line model simulation: a) First time period, b) Second time period, c) Third time period.

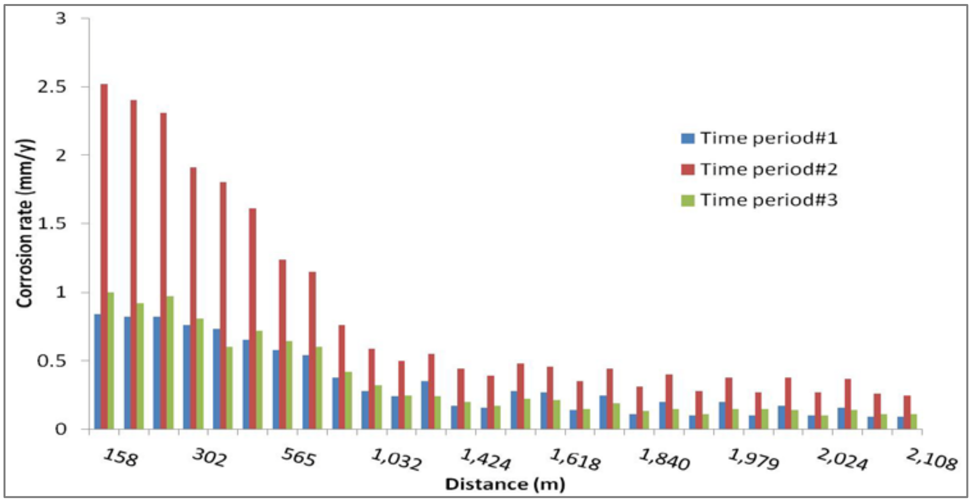

Figure 6: Predicted TLC rate for Line A.

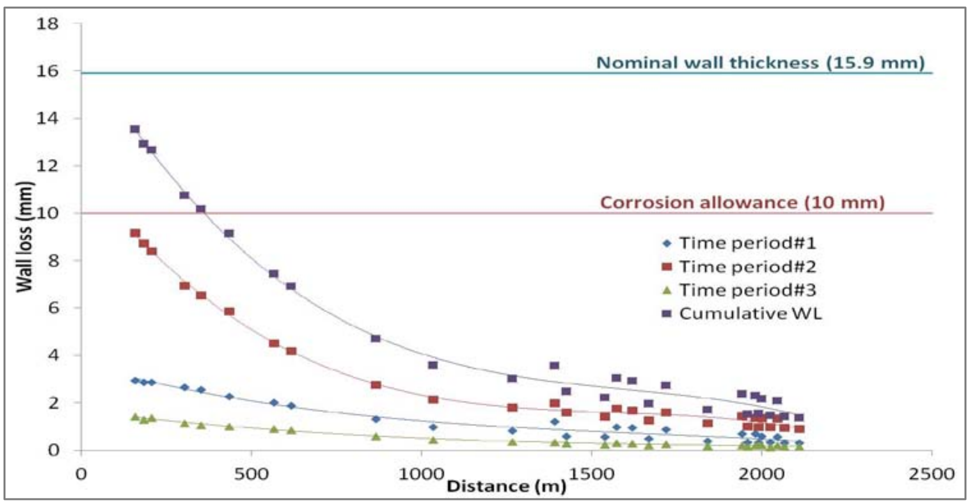

Figure 7: Calculated wall thickness loss values for the three time periods and the total cumulative wall thickness loss value.

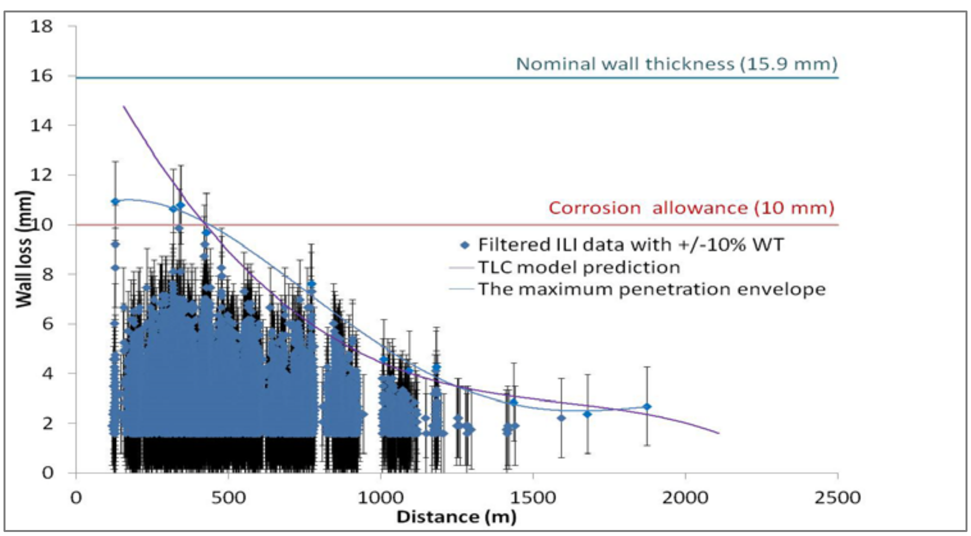

Figure 8: Comparison between filtered MFL data (with error bars equivalent to ±10% wall thickness due to instrument accuracy) and the TLC model predictions.

Part II: Analysis of other lines

In order to determine the validity of the newly developed methodology and the accuracy of the TLC model, a similar analysis was done for another seven lines where complete datasets were available. A summary of that work is presented in Figure 9 for another four lines. In all cases the maximum penetration envelope for the ILI data agrees well with the clustered data (representing uniform TLC) suggesting there was no localized attack. The performance of the TLC model can be considered as reasonable as the predictions agree well with the maximum penetration envelope. This is true for all lines with the exception of Line C where the model slightly under-predicts the rate of TLC attack. However, when error bars are taken into account this difference does not seem to be statistically significant. This is summarized in Figure 10 where a parity plot is shown for all eight lines which were analyzed. Only the maximum wall thickness loss ILI data for an entire line was used here and compared with the prediction for the same location in the line. A reasonable agreement is obtained in six of the eight cases, which is within the margins of measurement error. In the other two cases the error was less than ±20%.

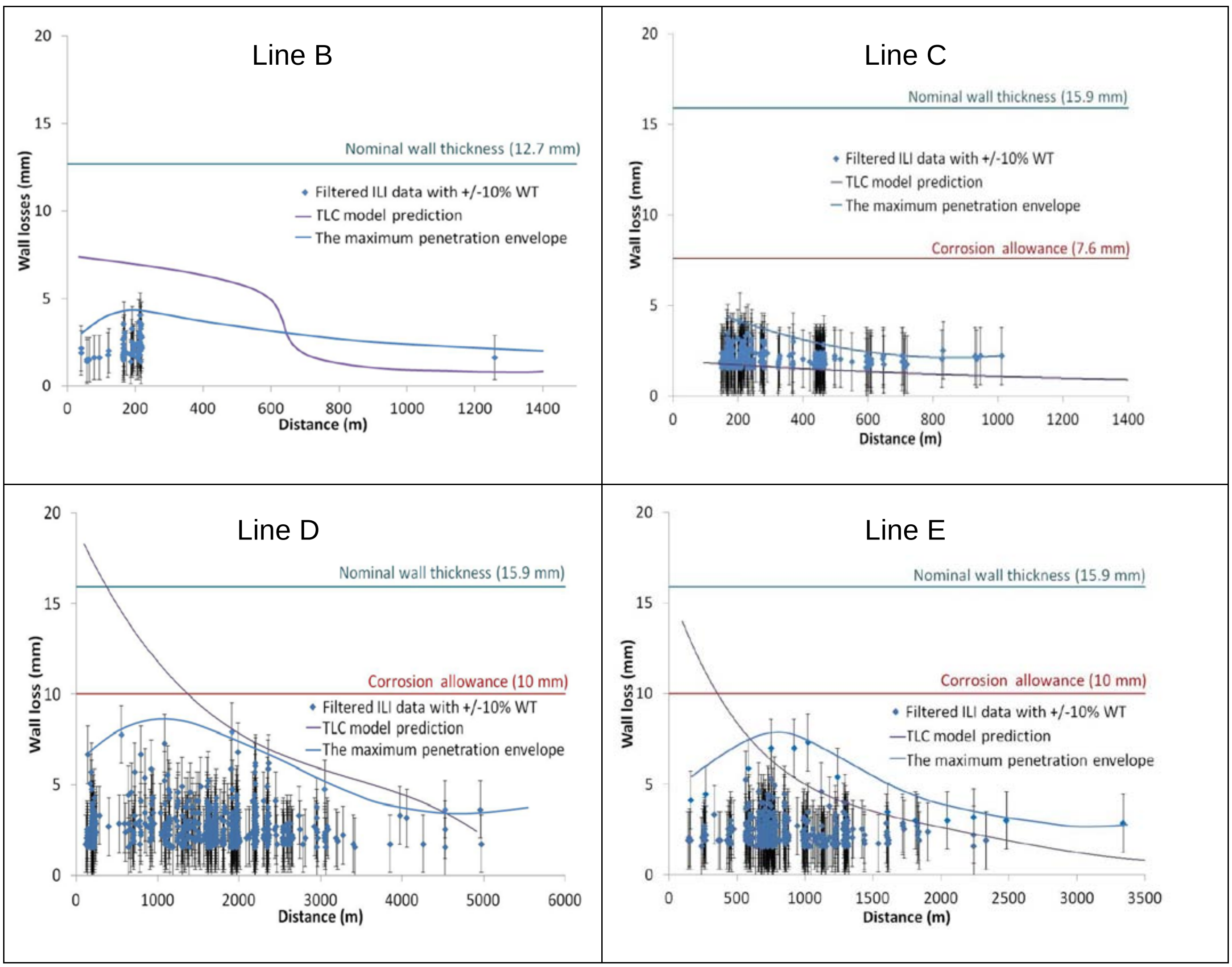

Figure 9: Comparison between TLC model prediction and reprehensive corrosion features filtered from MFL data.

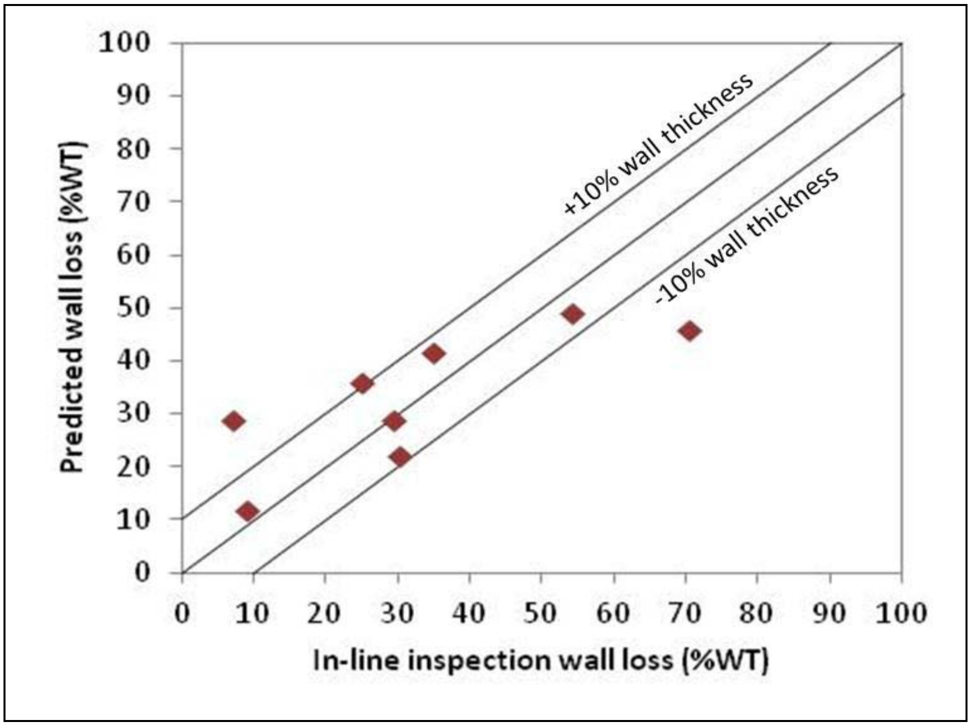

Figure 10: Parity plot between maximum wall thickness loss obtained from the ILI data and the predicted TLC data for eight different lines.

DISCUSSION

Overall the model predictions show a reasonably good agreement with the ILI data. However, there are a few gaps in our understanding of TLC which affect the comparison between TLC model predictions and ILI data. Since the mechanistic TLC prediction model is only a reflection of the current knowledge, it cannot be expected to predict phenomena which are not yet understood. In any case the TLC model is currently used to evaluate the risk levels for TLC in various pipelines and to prioritize TLC mitigation programs and pipeline corrosion assessment strategies.

CONCLUSIONS

- An effective methodology was developed to analyze and validate the field data including the operational parameters which vary over time and length of the line, as well as the ILI data which are inherently complicated and not always reliable. The field data were processed to enable effective comparison with TLC model predictions.

- The TLC prediction model selected in this study showed a reasonable agreement with the ILI data in six of the eight lines analyzed, which is within the margins of measurement error. In the other two lines the predictions were within ±20% of the ILI data.

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