

**Line Modeling of CO₂ Corrosion of
Offshore Pipeline**

By

Mohd Safwan Izzudin Bin Ramli

(10775)

Dissertation submitted in partial fulfillment
of the requirement for the
Bachelor of Engineering (Hons)
(Mechanical Engineering)
January 2012

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Approved by,

(AP Ir Dr.Mokhtar Bin Che Ismail)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

January 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOHD SAFWAN IZZUDIN BIN RAMLI

ABSTRACT

CO₂ corrosion has been a recognized problem in oil and gas production and transportation facilities for many years. The common approach in predicting CO₂ corrosion is by using point modeling where corrosion rate is calculated based on inlet design parameters. This approach is conservative as it only considers the maximum design. Line modeling is multi-point simulation that allows us to get the information on corrosion rates at each point along the pipeline, thus allowing us to make more accurate and precise decisions. This project will analyze both modeling methods and compared both results with the field corrosion rate data. A case study from Malaysia oilfield is chosen for total length of 10 kilometers pipeline. MULTICORP software is used to simulate the point modeling and line modeling. For the first 3 kilometers, both modeling approaches predict almost similar corrosion rates. For the remaining part of the pipeline, which is from 3-7 kilometers, line modeling approach predicts closer corrosion rate to the actual corrosion rate compared to point modeling approach. The accuracy of either point modeling or line modeling depends on variability of main process parameters such as temperature and fluid flow.

ACKNOWLEDGEMENTS

The author wishes to take the opportunity to express his utmost gratitude to the individual that have taken the time and effort to assist the author in completing the project. Without the cooperation of these individuals, no doubt the author would have faced some minor complications throughout the course.

First and foremost the author's utmost gratitude goes to the author's supervisor, AP Ir Dr Mokhtar Bin Che Ismail. Without his guidance and patience, the author would not succeed to complete the project. To the Final Year Research Project Coordinator, Mr Faizairi for providing him with all the general information required to complete the project.

To all individuals who helped the author in any way, but whose name is not mentioned here, the author thank you all.

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CHAPTER 1

INTRODUCTION

1.1 Project Background

CO₂ corrosion is the main corrosion threat in upstream exploration and production sector which governs the material selection of the pipeline. CO₂ corrosion prediction is usually based on design parameters which do not consider variation of parameters along the pipeline. Corrosion prediction based on single parameter is defined as point modeling where the corrosion rate is assumed to be the same along the pipeline. All decisions such as on designing and process parameters will be based on that corrosion rate. But, in reality, variables affecting CO₂ corrosion rate are not constant throughout the pipeline. Hence, the corrosion rates at any points along the pipeline will also differ. CO₂ corrosion prediction approach based on variation of parameters along the pipeline is defined as line modeling. More accurate CO₂ corrosion prediction can be done using line modeling.

1.2 Problem Statement

Prediction of CO₂ corrosion using point modeling is based on conservative approach which does not consider the variation of parameters along the pipeline. As process parameters can vary along the pipeline, corrosion prediction can be optimized using line modeling. The differences between point modeling approach with line modeling approach are not known.

1.3 Objectives and Scope of Study

This project is a study and research on the CO₂ corrosion phenomenon occurred on the pipelines in oil and gas field. The study is using specially designed software, MULTICORP to analyzed line modeling method in predicting CO₂ corrosion rate of offshore pipeline. Data from existing operated pipelines will be compared with the predicted corrosion rates from the model.

Objectives

1. To perform CO₂ corrosion prediction using MULTICORP model for offshore pipeline based on point modeling and line modeling approaches.
2. To compare both modeling results with the actual corrosion rates.

Scope of study

This project uses MULTICORP, specially designed software to run line modeling of CO₂ corrosion along the pipeline. Data from existing operated pipeline is used as the input data. Results from other researches done previously and actual CO₂ corrosion rate data are also considered to verify the model's results.

CHAPTER 2

LITERATURE REVIEW

2.1 CO₂ Corrosion Models

It is apparent that CO₂ corrosion of carbon and low alloy steels has been, and remains, a major cause of corrosion damage in oil and gas field operations (M.B. Kermani and D. Harrop, The impact of corrosion on the oil and gas industry, SPE Production Facilities, 1996, p.186-190). The industry relies heavily on prediction models which takes into account temperature, CO₂ pressure, pH scale, fluid flow and flow velocity to predict corrosion rates and allow them to take considerable protective steps in design stage and on process parameters. A revised version of prediction model which include steel composition factor was published in 1995 (C. de Waard, U. Lotz and A. Dugstad,).

Several available CO₂ corrosion prediction models are reviewed in paragraphs below. The CORMED model developed by Elf predicts the probability of corrosion in wells (J-L, Crolet and M.R. Bonis, Prediction of the risks of CO₂ corrosion in oil and gas well, 1996). The model identified the CO₂ partial pressure, in-situ pH, and the amount of free acetic acid as the only influencing factors for down hole corrosion and predicts either a low risk, medium risk or a high risk for tubing perforation within 10 years.

The LIPUCOR corrosion prediction program calculates corrosion rates based on temperature, CO₂ concentration, water chemistry, flow regime, flow velocity, characteristic of the produced fluid, and material composition. Meanwhile SSH model is a worst case based model mainly derived from laboratory data at low temperature and a combination of laboratory and filed data at temperatures above 100⁰C.

An empirical model developed by NORSOK Norwegian standard (NORSOK 2005) for prediction of CO₂ corrosion in straight pipes has been coupled to selected models for pipelines thermal/ hydraulic calculations to stimulate CO₂ corrosion rate along oil pipelines.

Electronic Corrosion Engineer (ECE) program is a tool for the quantitative estimation of corrosion rates and the selection of materials for gas and oil production systems and processing facilities. It enables corrosion-rate prediction for sweet- and sour-service conditions based on the fundamental chemistry of the solubility of the corrosion products. Critical factors such as oil API gravity, the water cut, the flow rates and the angle of flow are all taken into account. It provides output for multiple positions along a flow line or up a tubing string. Most notable is the instant display of corrosion rates profile.

M. B. Kermani and L. M. Smith said (1997) various mechanism have been postulated for the corrosion process but all involve either carbonic acid or the bicarbonate ion formed on dissolution of CO₂ in water – this leads to rates of corrosion greater than those expected from corrosion in strong acids at the same pH. CO₂ dissolves in water to give carbonic acid, a weak acid compared to mineral acids as it does not fully dissociate.

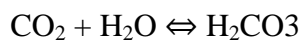
In short, CO₂ corrosion along pipeline is affected by two groups of parameters. The first group includes the parameters that influence flow dynamics inside the pipeline such as flow characteristics (velocity, density, and viscosity) and pipeline characteristics (internal diameter and wall roughness). The second group includes the parameters that influence the corrosion initiation and growth such as concentration of the corrosive component, temperature, pH, and steel composition.

2.2 CO₂ Corrosion Theory

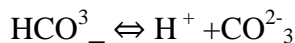
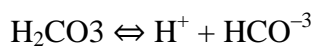
Aqueous CO₂ corrosion of steel is an electrochemical process involving the anodic dissolution of iron and the cathodic evolution of hydrogen. In uniform CO₂ corrosion of mild steel, a number of chemical, electrochemical, and transport processes occur simultaneously. They are briefly described below.

Chemical Reactions

When dissolved in water, CO₂ is hydrated to give carbonic acid (H₂CO₃):



which then dissociates in two steps:



In practical CO₂ corrosion situations, many other species are present in the water solution. Therefore, a large number of additional chemical reactions can occur.

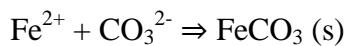
Chemical reactions are sometimes very fast compared to all other processes occurring simultaneously, thus preserving chemical equilibrium throughout the solution. In other cases, when chemical reactions proceed slowly, other faster processes (such as electrochemical reactions or diffusion) can lead to local non-equilibrium in the solution. Either way the occurrence of chemical reactions can significantly alter the rate of electrochemical processes at the surface and the rate of corrosion. This is particularly true when, as a result of

high local concentrations of species, the solubility limit is exceeded and precipitation of surface films occurs.

In a precipitation process, heterogeneous nucleation occurs first on the surface of the metal or within the pores of an existing film since homogeneous nucleation in the bulk requires a much higher concentration of species. Nucleation is followed by crystalline film growth.

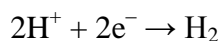
Under certain conditions, surface films can become very protective and reduce the rate of corrosion by forming a transport barrier for the species involved in the corrosion reaction and by covering parts of the metal surface.

In CO₂ corrosion, when the concentrations of Fe²⁺ and CO₃²⁻ ions exceed the solubility limit, they combine to form solid iron carbonate (FeCO₃) films according to:



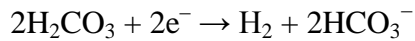
Electrochemical Reactions

The presence of CO₂ increases the rate of corrosion of mild steel in aqueous solutions primarily by increasing the rate of the hydrogen evolution reaction. In strong acids, which are fully dissociated, the rate of hydrogen evolution occurs according to:

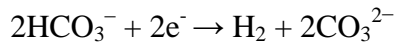


and cannot exceed the rate at which H⁺ ions are transported to the surface from the bulk solution (mass transfer limit). In CO₂ solutions, where typically

pH >4, this limiting flux of H⁺ ions is small; therefore, it is the presence of H₂CO₃ that enables hydrogen evolution at a much higher rate. Thus, for pH>4 the presence of CO₂ leads to a much higher corrosion rate than would be found in a solution of a strong acid at the same pH. The presence of H₂CO₃ can increase the corrosion rate in two different ways. Dissociation of H₂CO₃ serves as an additional source of H⁺ ions, which are subsequently reduced. In addition, there is a possibility that direct reduction of H₂CO₃ can increase the corrosion rate further:

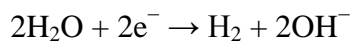


Both of these reaction mechanisms for hydrogen evolution have been included in the present model. It has been suggested that in CO₂ solutions at pH >5 the direct reduction of the bicarbonate ion becomes important:



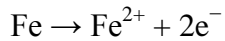
which might be true as the concentration of HCO₃⁻ increases with pH and can exceed that of H₂CO₃. However, it is difficult to experimentally distinguish the effect of this particular reaction mechanism for hydrogen evolution.

Hydrogen evolution by direct reduction of water:



can become important only at CO₂ partial pressure (pCO₂) <<1 bar and pH >5 and is therefore rarely an important factor in practical CO₂ corrosion situations.

The electrochemical dissolution of iron in a water solution:



is the dominant anodic reaction in CO₂ corrosion. It has been studied extensively in the past with several multistep mechanisms suggested to explain the various experimental results. Even if the overall anodic reaction does not suggest any dependency on pH, numerous studies have revealed that in strong acidic solutions the reaction order with respect to OH⁻ is between 1 and 2. Measured Tafel slopes are typically 30 mV to 40 mV. This subject, which is controversial with respect to the mechanism, is reviewed in detail by Drazic³⁰ and Lorenz and Heusler. The anodic dissolution in aqueous CO₂ solutions has not been the subject of detailed mechanistic studies, until recently.

The mechanism for strong acids, suggested by Bockris frequently has been assumed to apply in CO₂ solutions in which typically pH >4. It was overlooked that the experimental results presented by Bockris shows that the pH dependency decreases rapidly as pH >4, suggesting a change in mechanism or a different rate-determining step.

In the present study, the results from a recent study by Nestic were used and it was confirmed that the anodic dissolution of iron does not depend significantly on OH⁻ concentrations above pH 4; however, it is affected by the presence of CO₂, as previously indicated by Davies and Burstein³⁵ and Videm.

Transport Processes

From the description of the electrochemical processes it is clear that certain species in the solution will be produced in the solution at the metal surface (e.g., Fe^{2+}) while others will be depleted (e.g., H^+). The established concentration gradients will lead to molecular diffusion of the species toward and away from the surface.

In cases when the diffusion processes are much faster than the electrochemical processes, the concentration change at the metal surface will be small. Vice versa, when the diffusion is unable to “keep up” with the speed of the electrochemical reactions, the concentration of species at the metal surface can become very different from the ones in the bulk solution. On the other hand, the rate of the electrochemical processes depends on the species concentrations at the surface. Therefore, there exists a two-way coupling between the electrochemical processes at the metal surface and processes in the adjacent solution layer.

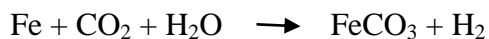
The same is true for chemical reactions that interact with both the transport and electrochemical processes in a complex way, as will be described. In most practical systems, the water solution moves with respect to the metal surface. Therefore, the effect of convection on transport processes cannot be ignored. Near-solid surfaces, in the boundary layer, time-averaged convection is parallel to the surface and does not contribute to the transport of species to and from the surface.

However, transient turbulent eddies can penetrate deep into the boundary layer and significantly alter the rate of species transport to and from the surface. Very close to the surface no turbulence can survive and the species are

transported solely by diffusion and electro migration as described in the following paragraph. Many of the dissolved species in CO₂ solutions are electrically charged and have different diffusion coefficients. This means that they diffuse through the solution with different “speeds.” Consequently, any diffusion occurring as a result of the existence of concentration gradients will tend to separate the charges. This will be opposed by strong, short-range, attraction forces between opposing charges.

Therefore, only a small separation of charge can occur, building up to a potential gradient within the solution that will tend to “speed up” the slower diffusing ions and “slow down” the faster ones, a process called electro migration or simply migration.

The general overall reaction of CO₂ corrosion is:



2.3 Keys Parameters Affecting CO₂ Corrosion

The effect of CO₂ partial pressure

In the case of scale-free CO₂ corrosion, an increase of CO₂ partial pressure (P_{CO₂}) typically leads to an increase in the corrosion rate. The commonly accepted explanation is that with P_{CO₂} the concentration of H₂CO₃ increases and accelerates the cathodic reaction, and ultimately the corrosion rate. However, when other conditions are favorable for formation of iron carbonate scales, increased (P_{CO₂}) can have a beneficial effect. At a high pH, higher P_{CO₂} leads to an increase in bicarbonate and carbonate ion concentration and a higher super saturation, which accelerates precipitation and scale formation.

The effect of Temperature

Temperature accelerates all the processes involved in corrosion: electrochemical, chemical, transport, etc. One would expect then that the corrosion rate steadily increases with temperature, and this is the case at low pH when precipitation of iron carbonate or other protective scales does not occur. The situation changes markedly when solubility of iron carbonate is exceeded, typically at a higher pH. In that case, increased temperature accelerates rapidly the kinetics of precipitation and protective scale formation, decreasing the corrosion rate. The peak in the corrosion rate is usually seen between 60°C and 80°C depending on water chemistry and flow conditions.

The effect of pH

The pH value is an important parameter in corrosion of carbon and low alloy steels. Typical pH in CO₂ saturated condensed water is about pH 4 or somewhat less. In buffered brines, one frequently encounters $5 < \text{pH} < 7$. At pH 4 or below, direct reduction of H⁺ ions, Eq. (5) is important particularly at lower partial pressure of CO₂ and the pH has a direct effect on the corrosion rate.

However, the most important effect of pH is indirect and relates to how pH changes conditions for formation of iron carbonate scales. High pH results in a decreased solubility of iron carbonate and leads to an increased precipitation rate and higher scaling tendency. To illustrate this, the experimental results from Chokshi et al. for various pH and super saturations are shown below. At lower super saturations obtained at pH 6 the corrosion rate does not change much with time, even if some iron carbonate precipitation occurs, reflecting the fact that a relatively porous, detached and unprotective scale is formed. The higher pH 6.6 results in higher super saturation, faster precipitation and

formation of more protective scales, reflected by a rapid decrease of the corrosion rate with time.

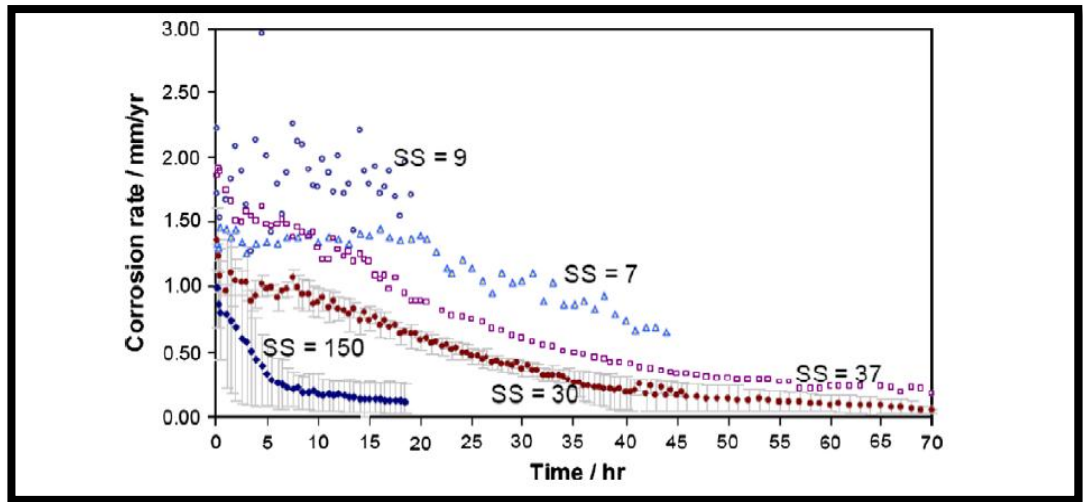
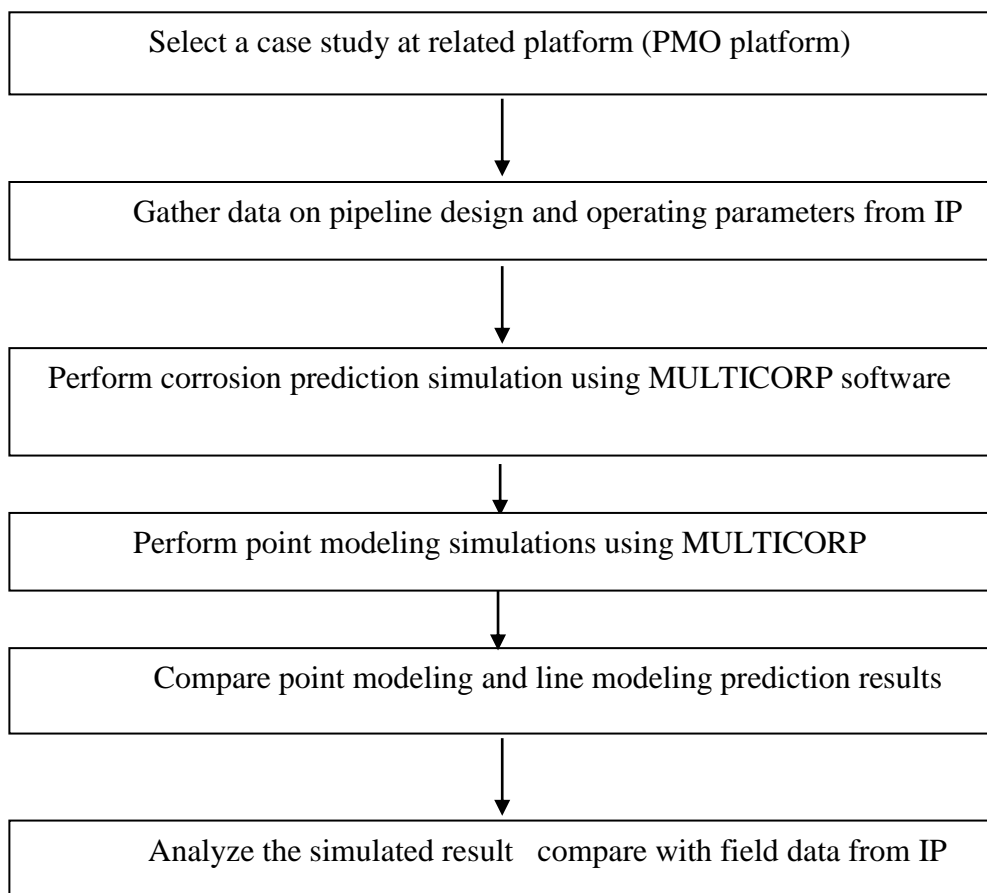


Figure 1: Effect of iron carbonate super saturation SS on corrosion rate obtained at a range of pH 6.0 – pH 6.6, for $5 \text{ ppm} < c_{\text{Fe}^{2+}} < 50 \text{ ppm}$ at $T = 80 \text{ }^\circ\text{C}$, under stagnant conditions. Error bars represent minimum and maximum values obtained in repeated experiments.

CHAPTER 3

METHODOLOGY/PROJECT WORK

3.1 Project work



3.1.1 Selection of case study

A 10" crude oil transporting offshore pipeline from PETRONAS's platform is chosen as the subject for this project. Installed on 1982, it transports wet and semi processed crude oil from Kepong A platform to Tiong A platform. This pipeline has been operating for 29 years by now (1982-2011).

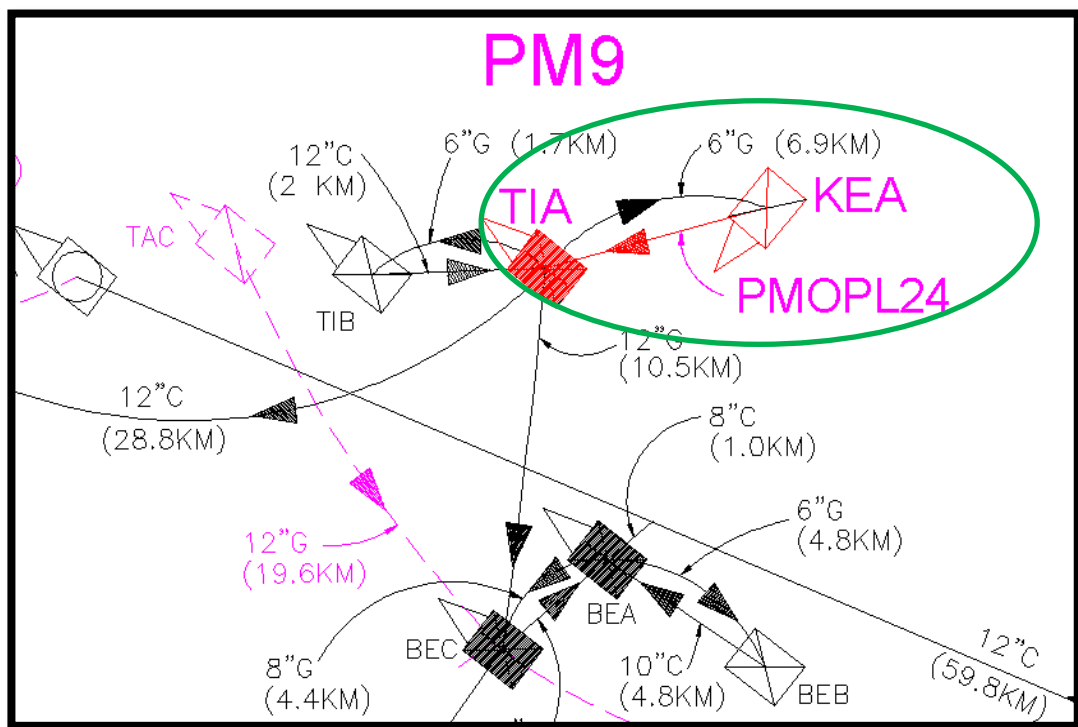


Figure 2: PMOPL24: 10" crude KEA to TIA layout

Table 1: Pipeline design specifications

Pipeline ID	PMOPL24
Pipeline Name	10" Crude KEA-TIA
Length	6.9 km
Location	Offshore
Nom Diameter	10.75 in (273.05 mm)
Nom Wall Thick	11.1 mm
Material Type	Carbon Steel
Material Grade	API 5L X52
Predominant Pipe Type	Seamless
Design Pressure	103.5 bar (1501 psi)
Test Pressure	145 bar (2103 psi)
Maximum Allowable Operating Pressure	40 bar (de-rated)
OP	28 bar (average)
Product	Wet, semi processed crude oil
Installation Year	1982
Design Life	20 yrs (2002)
Design Code	ASME B31.8
Operating Temp	55 °C @ inlet, 30 °C @ outlet
Min Water Depth	65.5 m @ KEA & 67.2 m @ TIA

Inspections are being done several times using Intelligent Pigging (IP) for maintenance and data collection purposes due to its corrosive environment.

- 1994
 - (Defects reported (reporting threshold = 10%))

- Most severe was 21% due to mill defect
 - Remaining were group under pitting
- 1997
- 44 defects reported (reporting threshold = 10%)
 - Most severe was 17% due to pitting
- 2003
- 2186 defects; with 2127 due to metal loss, 59 due to mill defects
 - 2110 internal, concentrated at the first 500m from KEA
 - 76 external
 - Reporting threshold = 1%
 - Most severe was 45% internal (general corrosion)
- 2006
- 10896 defects
 - 10804 are metal loss defects and 92 manufacturing defects
 - 10803 internal defects distributed along the pipeline, 88% were concentrated at the first 700m section of KEA.
 - 1 external defect at KEA riser/splash zone area
 - Maximum reported wall loss is 46% @ LD=211.94m and LD=114.58m
 - All defects were distributed throughout the pipeline, interacting at some locations mostly within the first 700m section.

Table 2: Pipeline operating parameters

Inlet Temp (°C)	27 (min)/ 65 (max)
Outlet Temp (°C)	30
Inlet Pressure (bar)	28
Outlet Pressure (bar)	25
CO₂ (mole %)	0.532
H₂S (mole %)	0
CI availability (%)	40 (min)/ 70 (max)
Total flow rate (m³/d)	488 (min)/ 511 (max)
Crude oil flow rate (m³/d)	168
API gravity	27.5
Water flow rate (m³/d)	320 (min)/ 343 (max)
Water cut (%)	67
Inlet Fe count (ppm)	0.02 (min)/ 0.5 (max)
Inlet SRB count (cfu/ml)	1 – 100
Outlet SRB count (cfu/ml)	1

3.1.2 Line modeling using Multicorp

Pipeline topography data, inlet flow parameters and water chemistry data are used as the main input to start the simulation in Multicorp. As for flow parameters such as pressure, temperature and flow rate, only the inlet data are used. Then, the software will automatically calculate the associated values along the pipeline.

Overview on MULTICORP software:



Figure 3: Opening/Splash screen of MULTICORP software

MULTICORP is a transient mechanistic CO₂ corrosion prediction software package. It provides many new capabilities and enhancements compared to other CO₂ corrosion prediction model, which allow the user to significantly expand the scope of internal pipeline corrosion analyses:

Examples of the enhanced characteristics are:

- Mechanistic model of CO₂ and H₂S corrosion mechanism,
- Capability to perform batch run for a set of experimental data,
- Capability to perform Monte Carlo simulation of the corrosion process for uncertain data,

- Corrosion prediction correction based on the field data using case-based reasoning,
- Oil pipeline corrosion prediction with transition along the line

MULTICORP covers almost all key aspects of internal corrosion of mild steel oil and gas pipelines. It is based on solid theoretical foundations. Some of the models included are:

1. Kinetics of electrochemical reactions at the steel surface, such as iron dissolution, hydrogen evolution, etc.
2. Kinetics of solid state reactions at the steel surface, such as mackinawite scale buildup.
3. Dynamics of coupled transient transport of multiple species between the bulk solution and the steel surface, through the turbulent boundary layer and through a porous surface film.
4. Kinetics of chemical reactions including precipitation of solids such as iron sulfide, iron carbonate, etc.
5. Growth of iron carbonate and iron sulfide scales

It is possible to reliably predict the effects of key variables that affect internal pipeline corrosion such as:

- Effect of multiphase flow
- Effect of temperature

- Effect of CO₂ partial pressure
- Effect of H₂S content
- Effect of organic acids
- Effect of pH and brine chemistry
- Effect of steel type
- Effect of inhibition by crude oil and/or corrosion inhibitors
- Magnitude and morphology of localized attack

Table 3: Recommended range for data input

Parameters	Unit	Range
Multiphase flow		two- and three-phase flow
Temperature	°C	1-100
CO ₂ partial pressure	Mpa	0-2
H ₂ S content	MPa	0-1
Organic acid	ppm	0-10,000
pH		pH3-pH7

The input data includes flow-related data such as velocity, viscosity, and density and corrosion related data such as pH, temperature and CO₂ partial pressure. The output parameters are the parameters to be simulated along the pipeline. These parameters include corrosion rate, temperature, the effect of pH, total pressure, and CO₂ pressure along the pipeline.

User interface of the model is shown below:

Step 1

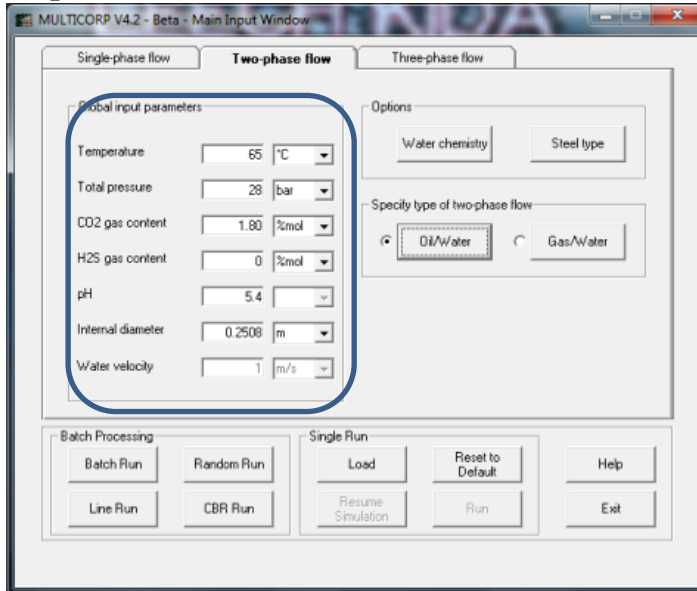


Figure 4: Flow parameters data

Step 2

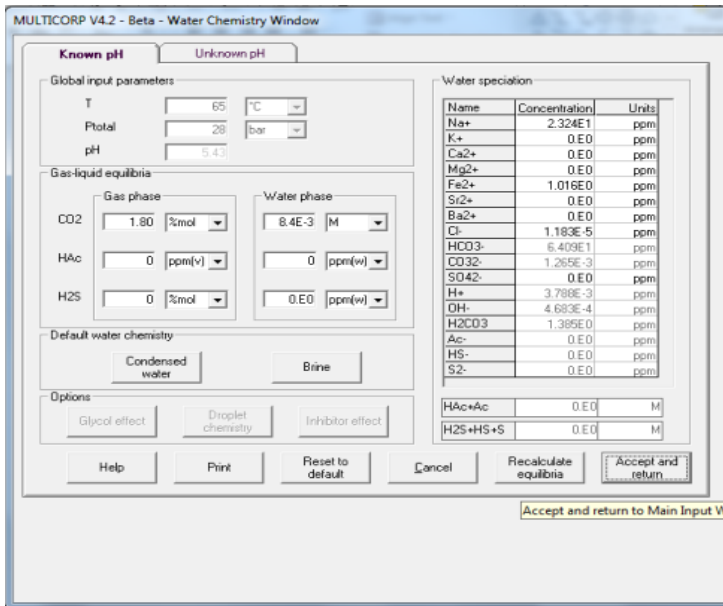


Figure 5: Water chemistry data

Step 3

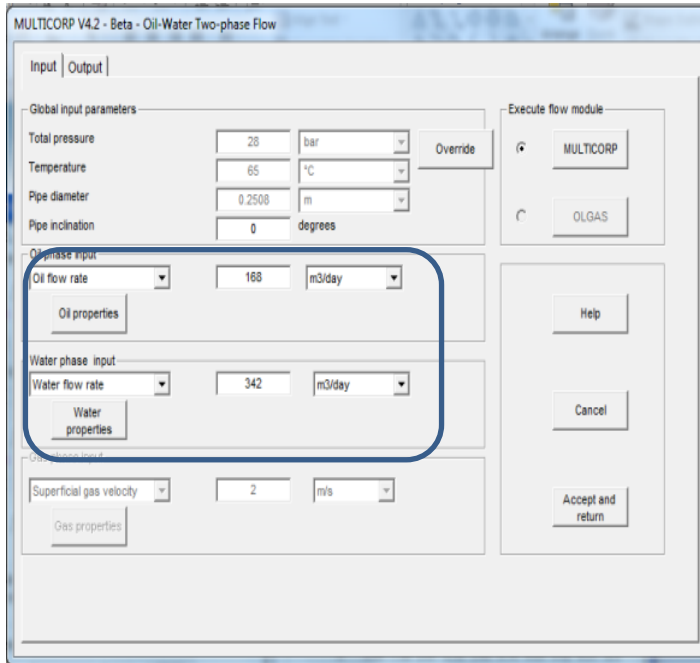


Figure 6: Oil-water phase data

Step 4

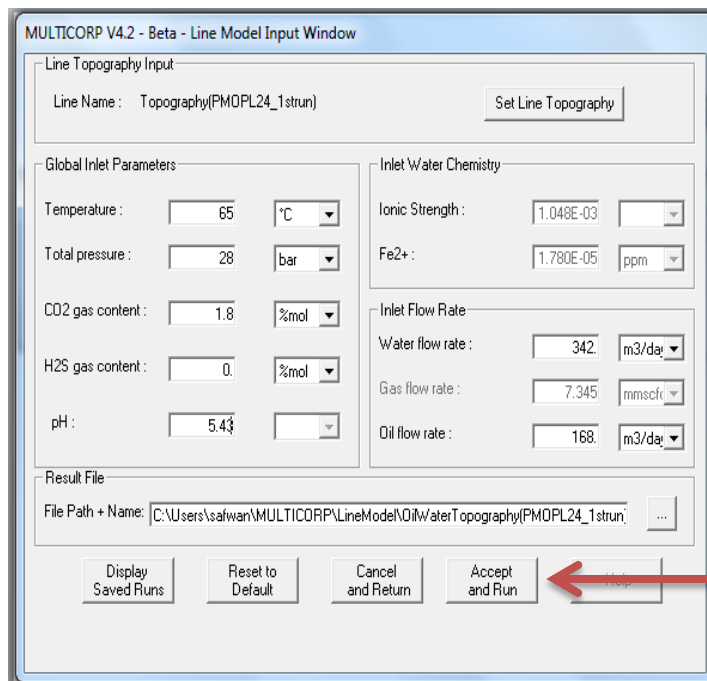


Figure 7: Pipeline inlet parameters

Accept and RUN

3.2 Timelines

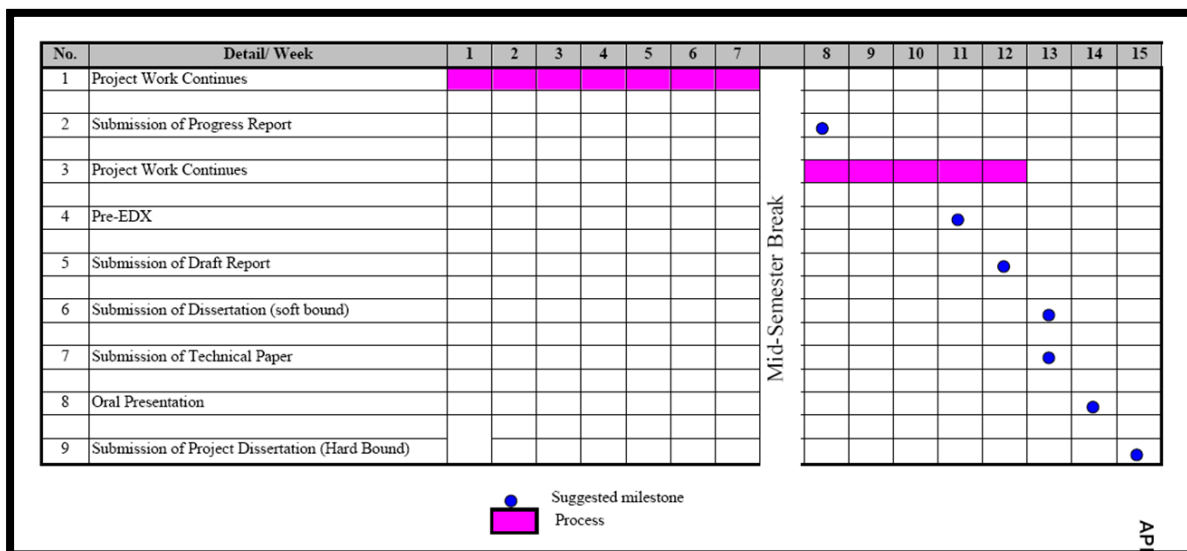


Figure 8: FYPII timeline

3.3 Tools required

This project is using MULTICORP software, corrosion prediction model software. It is integrated with a multiphase flow predictor and a water chemistry calculator and firmly based on theoretical foundations. As the package is based on a mechanistic (theoretical) model, the equations behind MULTICORP V4.2 are faithful descriptors of the important physico-chemical processes underlying corrosion. This is in contrast with the other models, all of which are empirical or semi-empirical. It will incorporate most current research findings as they become available. It is multifunctional software that has 3 main modeling function; point modeling, batch processing model and line modeling.

MULTICORP V4.2 has many advantages when compared to other related software packages available to users.

Point Model

- Corrosion prediction at a single “point” (for one set of conditions)

Batch Processing Model

- Automatic corrosion prediction for multiple points, with the corrosion prediction at each point being independent from the others (sequential and probabilistic mode)

Line Model

- Corrosion prediction along the length of a line (pipeline, well, etc.).
- Multi-point simulation with environmental parameters such as temperature, pressure, species concentration and flow regime changing from point to point along the pipeline due to external and internal factors.
- Corrosion at upstream points affects conditions and corrosion at downstream points in the line

CHAPTER 4

RESULTS AND DISCUSSION

This section will discuss the simulation trials that have been done and how the data be analyzed. The results from point modeling and line modeling are analyzed and then, the predicted corrosion rate proposed by Multicorp is compared to the actual corrosion rate recorded by pigging device.

4.1 Selected Input Data

Table 4: Selected input data

Parameters	Unit	Range
Total Pipeline Length	km	6.9
Pipe thickness	mm	11.1
Internal Diameter	mm	250.85
Multiphase flow		Two phase flow (oil, water)
Temperature	°C	55(inlet), 30(outlet)
Pressure	bar	28(inlet), 25(outlet)
CO ₂ partial pressure	% mol	0.532 (inlet), 0.255(outlet)
H ₂ S content	% mol	0
Soil Temperature	°C	20
pH		pH6.4 (inlet), pH6.6 (outlet)
Water Cut	%	67

4.2 Point Modeling Results

For point modeling, two points are taken for modeling, which are one at inlet and one at outlet point.

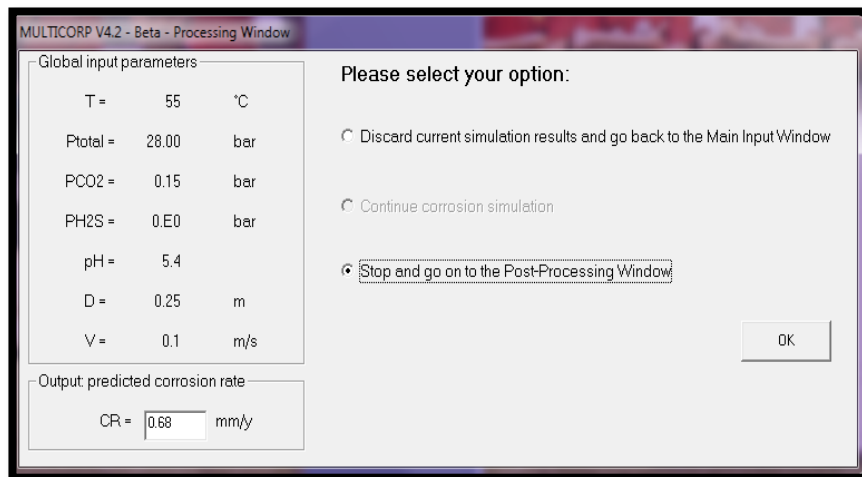


Figure 9: Point modeling at inlet of the pipeline

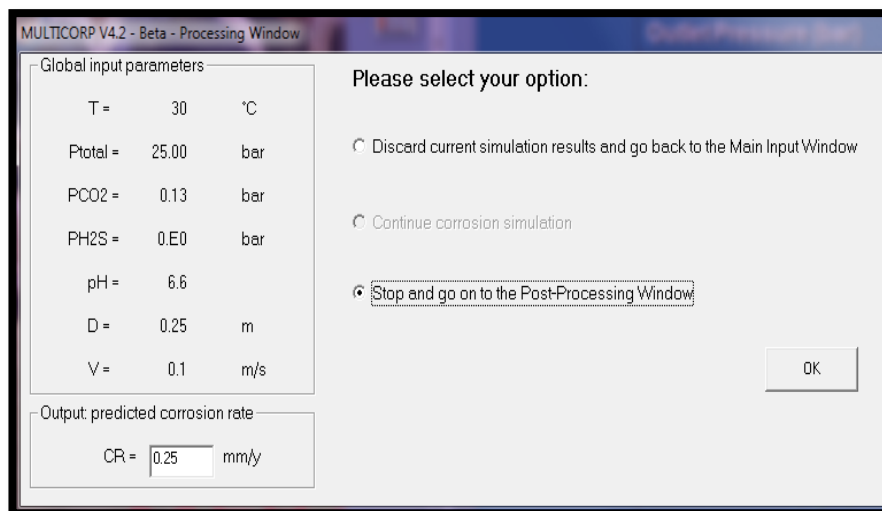


Figure 10: Point modeling at outlet of the pipeline

Point modeling at inlet point and outlet point of the pipeline yields corrosion rates of 0.68mm/y and 0.25mm/y respectively.

4.3 Line Modeling Results

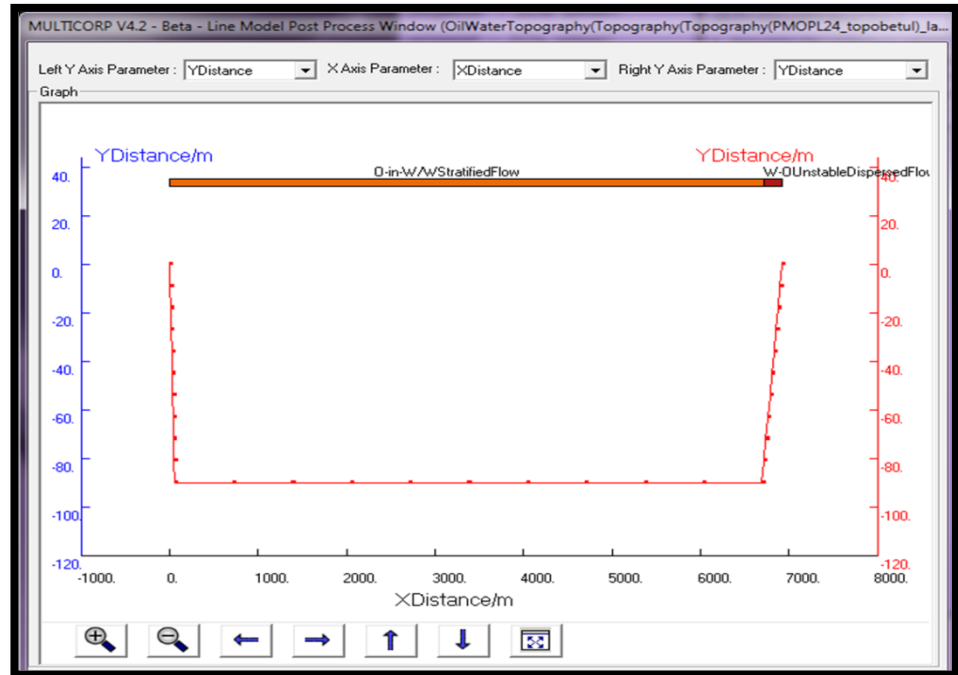


Figure 11: Topography of the pipeline

The pipeline starts from Kepong A platform (KEA) and end at Tiong A platform (TIA). It is 6.9km in length and has risers section at both side of the pipeline.

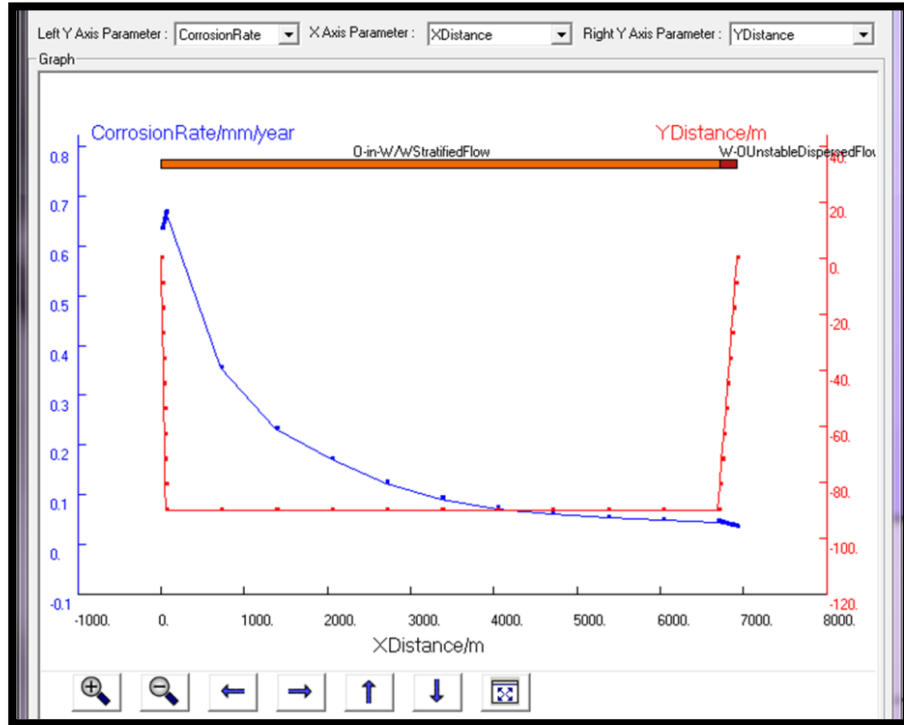


Figure 12: Predicted corrosion rates along the pipeline

The figure shows the predicted corrosion rates along the pipeline. The corrosion rates is decreasing along the pipeline. The highest corrosion rates are at the beginning of the pipeline which is, 0.66mm/y at the riser of KEA platform and the lowest corrosion rate appears at the end of the pipeline, which are 0.15mm/y at the riser of TIA.

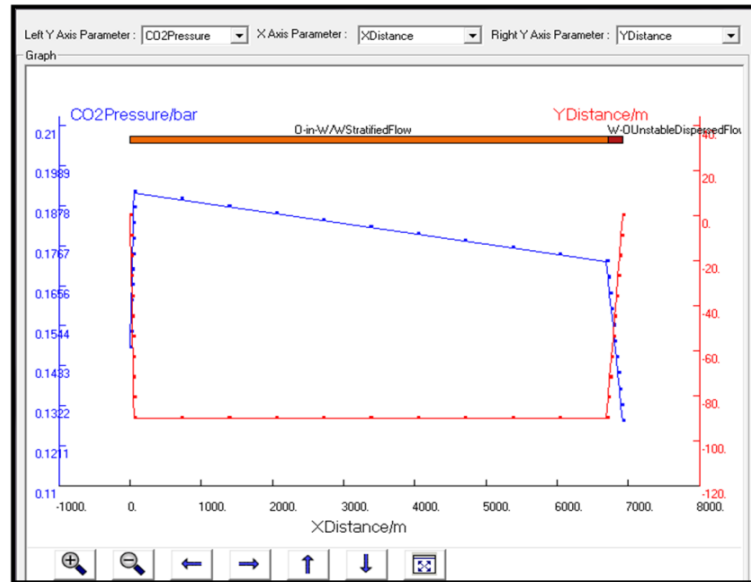


Figure 13: Characteristic of CO₂ pressure along pipeline

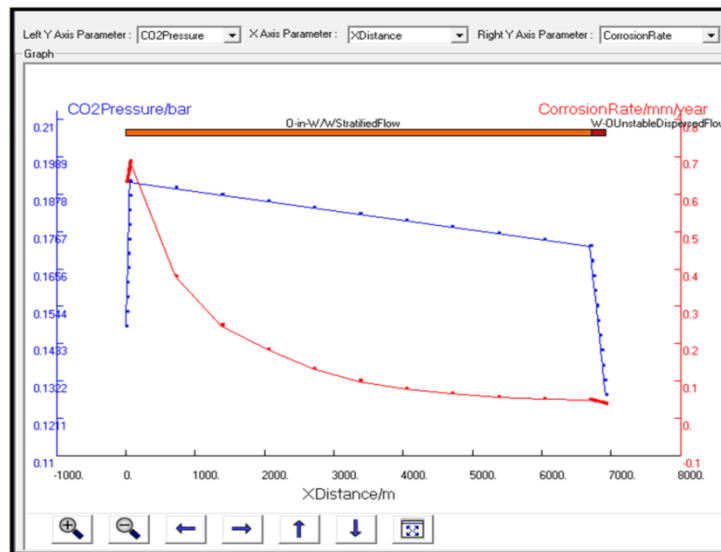


Figure 14: Graph CO₂ pressure vs Corrosion rate along pipeline

Figure 13 and 14 show characteristic of CO₂ pressure and corrosion rate along the pipeline. The highest CO₂ pressure is at the beginning which is 0.19 bar and decreasing until its lowest pressure at the outlet, which is 0.13 bar. The CO₂ pressure decreases because the fluid velocity decreases along the pipeline, hence decreasing the corrosion rate.

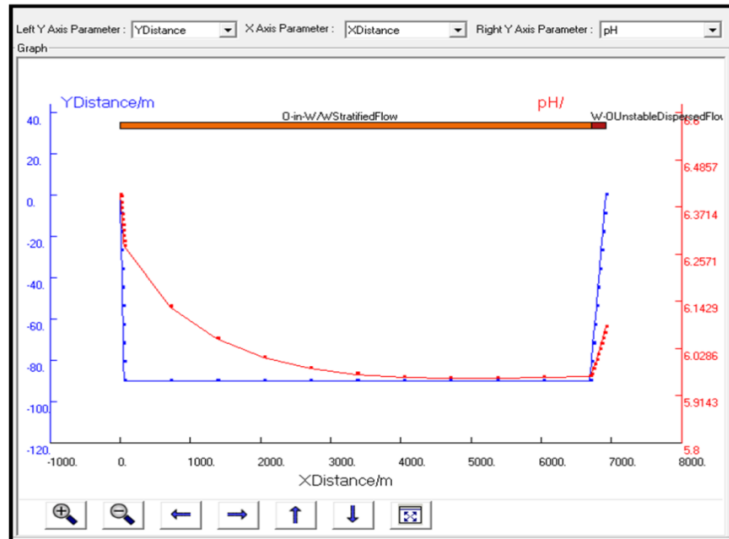


Figure 15: Characteristic of pH along pipeline

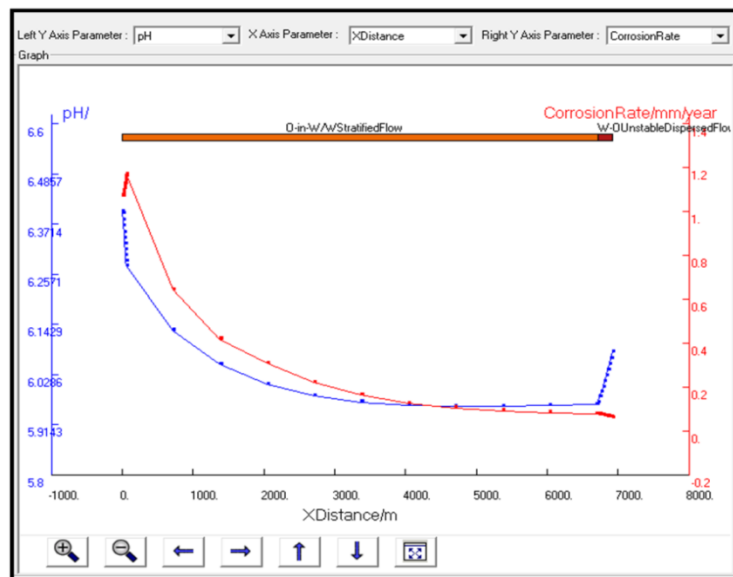


Figure 16: Graph pH vs Corrosion rate along pipeline

Figure 15 and 16 above show the characteristic of pH and corrosion rates along pipeline. The highest pH value is at the inlet which is 6.4 and it decreased and reaches pH of 5.9 at the outlet of the pipeline. This results in increasing the anodic and cathodic reaction which in turn increases the corrosion rate. From the graph, the corrosion rate is decreasing along the pipeline. It means that the contribution of pH on corrosion rate is minimal.

4.4 Discussion

Based on point modeling, corrosion rate simulated at the inlet of the pipeline is 0.68mm/y. Meanwhile, at the outlet of the pipeline, the corrosion rate calculated is 0.25mm/y. For line modeling, corrosion rate at the inlet is 0.66mm/y and it decrease exponentially until it reaches 0.15mm/y at the outlet of the pipeline.

Both modeling approaches predict almost similar corrosion rate at the inlet of the pipeline. It can be justified by the same parameters value that being used for both modeling. So, point modeling can be used at the for the inlet section as it is easier and yields almost similar result with line modeling.

At the outlet of the pipeline, point modeling predicts higher corrosion rate, which is 0.25mm/y compared to line modeling result, which is 0.16mm/y. It is clear that pH value is decreasing and become lowest at the end of the pipeline. However, pH effect on the overall corrosion rate is minimal as shown by figure 16. Point modeling takes pH effect significantly, thus the corrosion rate predicted is higher compared with line modeling which considers corrosion at upstream point will affects condition and corrosion at downstream along the pipeline.

The actual corrosion rates of the pipeline are collected from pigging data. The corrosion rate at the inlet of the pipeline is 0.19mm/y, which is the highest rate. Then, the corrosion rates decrease to the end of the pipeline until it reaches 0.15mm/y, which is the lowest corrosion rate.

Table 5: Corrosion rates for each approach at inlet and outlet

Approach	Inlet(mm/y)	Outlet(mm/y)
Actual field data	0.19	0.15
Point modeling	0.68	0.25
Line modeling	0.66	0.16

Next, both modeling approaches are compared with the actual corrosion rates. At the inlet point, both point modeling method and line modeling method yield slightly higher corrosion rates compared to the actual corrosion rate. This could be due to the result of the inhibitor's effect that has not been considered comprehensively in the model. Both are acceptable because higher corrosion rate will prompt us to take more cautious protection step and reduce the possibility of underestimation in designing stage and also in process parameters. Hence, point modeling is preferable than line modeling as point modeling is easier and faster approach.

At the outlet point, line modeling is able to predict the corrosion rate almost accurately meanwhile point modeling predicts slightly higher. Line modeling shows very good agreement with the actual data as line modeling takes into account the variation of parameters along the pipeline.

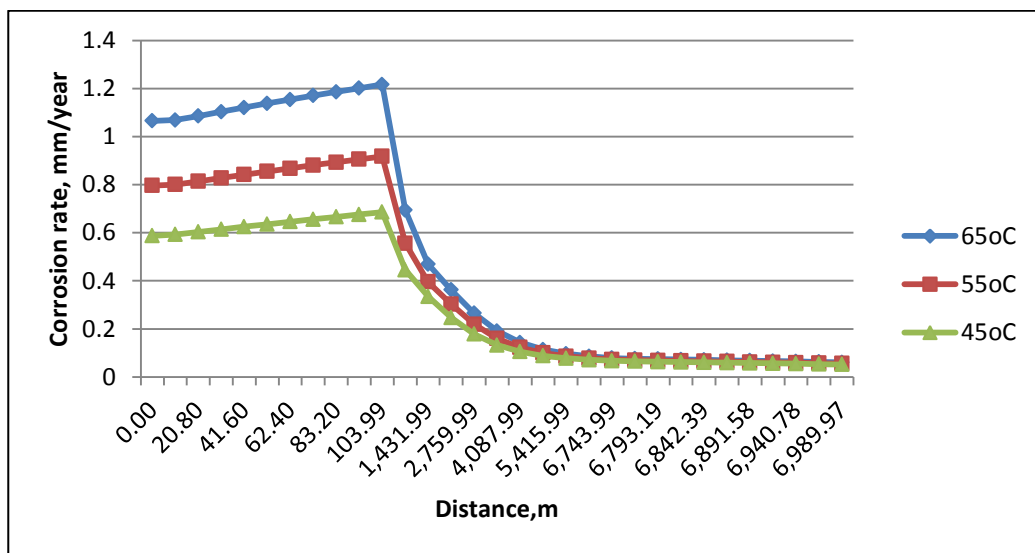


Figure 17: Variation of corrosion rate along pipeline at different temperature

Figure 17 shows the variation of corrosion rate along pipeline at different temperature. Process with higher initial temperature experiences higher corrosion

rate at the beginning of the flow. It is clear that initially the corrosion rates increased at beginning of the pipeline until at a certain length, which is at 104m from inlet. It is because the flow is increasing as it flows downward based on the topography of the pipeline.

The pipeline then bends into a straight horizontal shape. The corrosion rate starts to decrease as the velocity decrease along the pipeline after the bending. As all the processes reached almost the same temperature at the end of the pipeline, which is the surrounding temperature, the corrosion rates of all the processes are almost identical.

Based on figure 17, the highest predicted corrosion rate is at 104 meter from inlet. Then the corrosion rates decreased until it reaches the outlet of the pipeline. For the first 3 kilometer, the predicted corrosion rates do not varies too much. So, the design parameters for this part of pipeline are same. Hence, point modeling is preferable to be used to predict the CO₂ corrosion rate as it is easier and faster and yields similar corrosion rate with line modeling.

For the rest of the pipeline, which is from 3-7 kilometers, the corrosion rates are much lower than the inlet part of the pipeline. So, the design parameters of this part of pipeline will be different compared with the inlet part of the pipeline. For example, pipeline thickness for this part of pipeline should be smaller compared with the inlet part. Therefore, line modeling is preferable to predict CO₂ corrosion rates for this part of pipeline as it can predicts almost similar with the actual corrosion rates. As a result, significant amount of cost can be saved compared if using point modeling for this part of pipeline.

CHAPTER 5

CONCLUSION

For the first 3 kilometers, both corrosion prediction approaches predict almost similar corrosion rate. So, point modeling is preferred to predict corrosion rate at the inlet part of the pipeline as it is easier and faster than line modeling approach. For the remaining part of the pipeline, which is from 3-7 kilometers, line modeling approach predicts closer corrosion rate to the actual corrosion rate compared to point modeling approach. The accuracy of either point modeling or line modeling depends on variability of main process parameters such as temperature and fluid flow.

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