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Coupling NORSOK CO_2 Corrosion Prediction Model with Pipelines Thermal/Hydraulic Models to Simulate CO_2 Corrosion along Pipelines

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Abstract

Pipelines transporting oil and gas are vulnerable to internal corrosion when water forms a part of the transported fluids. The presence of carbon dioxide (CO2) in the fluid accelerates the corrosion rate due to its reaction with water which results in forming carbonic acid, and hence, water pH is reduced.

The corrosion rate prediction is an important task needed to manage and control the corrosion. The prediction can be carried on by selecting one of many empirical and mechanistic models that developed for corrosion rate prediction. One of these models is NORSOK model, an empirical model developed by NORSOK Norwegian standard for CO2 corrosion prediction in straight pipes.

In this paper NORSOK model has been coupled to thermal and hydraulic models to predict CO2 corrosion rate along pipelines.

Keywords: Corrosion, CO_2, pipeline

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Introduction

Internal and external corrosion is a common problem in pipelines transporting oil and gas containing corrosive components such as CO_2 and H_2S. In many mature oil wells, the water cut and CO_2 content may reach high level which forms a suitable environment for initiation and growth of corrosion.

To avoid the consequences of corrosion, process parameters should always be controlled within safe operating limits. To do so, corrosion rates at various values of the parameters are to be predicted to set the critical values of every parameter; and then the process should be operated below these critical values.

Efforts have been made to predict and control corrosion in many oil fields worldwide. As a result, many models and measurement techniques have been proposed ((Waard and Milliams 1975) , (Waard, Lotz et al. 1995), , (Jepson, Bhongrde et al. 1996) (Wang, Cai et al. 2002)) .

Srdjan Nesic et al. (Nesic, Cai et al. 2005) developed a comprehensive model for internal corrosion prediction in mild steel pipelines. The effects of many factors contribute to corrosion rate such as H2S, water entrainment in multiphase flow, corrosion inhibition by crude oil components and localized attack have been taken into account in the model.
Internal corrosion of pipelines 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.
An example of the corrosion prediction model of pipelines is the Ohio model which couple a dynamic model for flow regime prediction to mechanistic and semi-empirical models for corrosion prediction ((Zhang, Gopal et al. 1997) , (Jepson, Stitzel et al. 1997))
In this paper 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 simulate CO2 corrosion rate along oil pipelines.

Simulation of corrosion rate along oil pipelines

During oils transportation, temperature gradually decreases from the inlet temperature (at 0 km distance) due to heat transfer from the heated oil to the surroundings. In isothermal

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pipelines (where no intermediate heating stations are installed), the temperature will eventually decline to the surrounding temperature some kilometers after the inlet point depending on many factors such as the surrounding temperature, the overall heat transfer coefficient, velocity, and fluid heat capacity. The temperature at distance L along the pipeline can be calculated using the following equation (Huang and Chong 1995):

$$T_L = T_o + (T_i - T_o)e^{\alpha L} \tag{1}$$

$$\alpha = \frac{-k_{tot}\pi D}{GC}$$

Where

T_i=The inlet temperature ^oC.

T_o=The surrounding temperature ^oC.

k_{tot}=The overall heat transfer coefficient W/m2 ^oC (a function of the fluid heat convection factor and the pipe and coating heat conduction factor).

C=The heat capacity of the fluid J/kg. ^oC.

$G = \frac{\pi}{4}D^2V\rho_f$ is the mass flow rate of the fluid kg/s

ρ_f=Fluid density kg/m^2.

V=Fluid velocity m/s.

D=pipe diameter, m.

Corrosion rate is a function of temperature, so that different points along the pipeline are expected to corrode in different rates depending on the temperature at the specified point. According to NORSOK model (equation 2) (NORSOK 2005), CO_2 corrosion within temperature range of 20 to 120 ^oC can be calculated using the following empirical equation:

$$R_C = K_t \times fCO_2^{0.62} \times (S/19)^{0.146++0.0324\log(fCO_2)} f(pH)_t \tag{2}$$

From equation 2, CO_2 corrosion depends on four factors that in turn depend on temperature. These factors can be summarized as shown in table 1.

To calculate CO_2 corrosion rate along a pipeline, equation 1 is firstly used to calculate temperature distribution along the pipeline using a suitable length interval and assuming constant overall heat transfer coefficient and surrounding temperature.

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Table 1: The effect of the four parameters along the pipeline

Parameter	Effect of temperature	The expected change along pipeline
K_t (temperature-dependant constant)	Increases from 5 to 60 ^oC and then decreases up to 150 ^oC (As shown in table 2)	Decrease with distance
fCO_2 (Fugacity of CO_2)	Decreases with temperature	Decreases with distance due to stronger dependency on system pressure (P) which decreases along the pipeline. $fCO_2 = a \times P_{CO2}$ $a = 10^{P(0.0031-1.4T)}$
S (Wall shear stress)	Increases with viscosity and density which in turn decreases with temperatures.	Increases with distance
$f(pH)_t$ (The effect of pH at any temperature)	As shown in table 3	Increases with distance

Table 2 and table 3 are then used to calculate kt and f(pH) along the pipeline.

Table 2: The change of kt with temperature (NORSOK 2005)

Temperature ^oC	k_t
5	0.42
15	1.59
20	4.762
40	8.927
60	10.695
80	9.949
90	6.250
120	7.770
150	5.203

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Table 3: The effect of pH (f(pH)) at different temperatures (NORSOK 2005)

Temperature ^{o}C	pH	f(pH)
5	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 2.0676 - 0.2309pH$ $f(pH) = 4.342 - 1.051pH + 0.0708pH^2$
15	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 2.0676 - 0.2309pH$ $f(pH) = 4.986 - 1.191pH + 0.0708pH^2$
20	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 2.0676 - 0.2309pH$ $f(pH) = 5.1885 - 1.2353pH + 0.0708pH^2$
40	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 2.0676 - 0.2309pH$ $f(pH) = 4.986 - 1.191pH + 0.0708pH^2$
60	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 1.836 - 0.1818pH$ $f(pH) = 15.444 - 6.1291pH + 0.8204pH^2 - 0.0371pH^3$
80	3.5≤pH≤4.6 4.6≤pH≤6.5	$f(pH) = 2.6727 - 0.3636pH$ $f(pH) = 331.68e^{-1.2618pH}$
90	3.5≤pH≤4.57 4.57≤pH≤5.62 5.62≤pH≤6.5	$f(pH) = 3.1355 - 0.4673pH$ $f(pH) = 21254e^{-2.1811pH}$ $f(pH) = 0.4014 - 0.0538pH$
120	3.5≤pH≤4.3 4.3≤pH≤5 5≤pH≤6.5	$f(pH) = 1.5375 - 0.125pH$ $f(pH) = 5.9757 - 1.157pH$ $f(pH) = 0.546125 - 0.071225pH$
150	3.5≤pH≤3.8 3.8≤pH≤5 5≤pH≤6.5	$f(pH) = 1$ $f(pH) = 17.634 - 7.0945pH + 0.715pH^2$ $f(pH) = 0.037$

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To calculate the fugacity of CO_2 (fCO_2), the total system pressure is calculated along the pipeline. If we assume a horizontal pipeline, the total pressure at the inlet should, at least, equals to all pressure losses from the inlet to the outlet. Darcy-Weisbach equation is used to calculate friction pressure losses within every interval. The Reynolds number and friction factor in any interval are calculated using the fluid density and viscosity at the temperature at that interval.

As corrosion will only takes place in the presence of water, we assume two phase (oil, water) system.

The density and viscosity of water at any temperature T is calculated as follows (assuming the water density at 20 ^oC is 998.2):

$$\mu_w(T) = ((T+273)-225.4)^{-1.637} \quad (3)$$

$$\rho_w(T) = \frac{998.2}{(1+0.0002(T-20))} \quad (4)$$

The oil density at any temperature T is calculated as follows (Huang and Chong 1995):

$$\rho_o(T) = \rho_{20} - \alpha(T-20) \quad (5)$$

$$\propto = 1.825 - 0.001315\rho_{20}$$

Where ρ_{20} = the oil density at 20 ^oC, kg/m3

Beggs and Robinson (Arnold and Stewartt 1998) correlations are used for viscosity prediction at any temperature T. these correlations are as follows:

$$\mu_o(T) = 10^{y\left(\frac{9T+160}{5}\right)^{-1.165}} - 1 \quad (6)$$

$$y = 10^{3.0324-0.02023G}$$

Where

$\mu_o(T)$= the viscosity (CP) at temperature T (^oC)

API gravity can be obtained from the following correlation

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$$API = \frac{141.5}{SG} - 131.5$$

Where SG is the specific gravity $= \frac{\rho_o(T)}{1000}$

The mixture density and viscosity at any temperature T is calculated as follows:

$$\frac{1}{\mu_m(T)} = \frac{\left(\frac{WC}{100}\right)}{\mu_w(T)} + \frac{\left(1-\frac{WC}{100}\right)}{\mu_o(T)} \tag{7}$$

$$\rho_m(T) = \rho_w(T) \times \frac{WC}{100} + \rho_o(T) \times \left(1-\frac{WC}{100}\right) \tag{8}$$

Where WC=water cut (%).

The mixture viscosity and density is then substituted in the following formula to calculate Reynolds number at the temperature T:

$$\mathrm{Re}(T) = \frac{\rho_m(T)VD}{\mu_m(T)} \tag{9}$$

In the case of laminar flow ($Re(T) \leq 2000)$, friction factor is calculated as follows:

$$f(T) = \frac{16}{\mathrm{Re}(T)} \tag{10}$$

In the case turbulent flow regime ($Re(T) > 2000)$, friction factor is calculated using Churchil (Churchill 1977) model as follows:

$$f(T) = 2\left[\left(\frac{8}{\mathrm{Re}(T)}\right)^{12} + (A+B)^{-1.5}\right]^{1/12} \tag{11}$$

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Where A, B, and c are given in equations 12-14

$$A = \left[2.457 \ln\left(\frac{1}{c}\right) \right]^{16} \quad (12)$$

$$B = \left(\frac{37530}{\mathrm{Re}(T)} \right)^{16} \quad (13)$$

$$c = \left(\frac{7}{\mathrm{Re}(T)} \right)^{0.9} + 0.27 \frac{e}{D} \quad (14)$$

e is the pipe roughness and D is the internal diameter.

The friction factor is introduced to Darcy-Weisbach equation as follows (Huang and Chong 1995):

$$\Delta P_f(T) = 4 f(T) \frac{\Delta L}{D} \rho_m(T) \frac{V^2}{T} \quad (15)$$

If we divide a pipeline into N interval, then the total pressure at the inlet can be calculated as follows:

$$P_T = \sum_{i=1}^{N} \Delta P_f(T) \quad (16)$$

And the pressure at the Mth interval T is calculated using the following equation:

$$P_{TM} = \sum_{i=M}^{N} \Delta P_f(T)_i = P_T - \sum_{i=1}^{M} \Delta P_f(T)_i \quad (17)$$

The wall shear stress at any temperature T is calculated using the following equation:

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$$S(T) = \frac{f(T)\rho_m(T)V^2}{8} \quad (18)$$

The calculation procedure is shown in Figure 1.

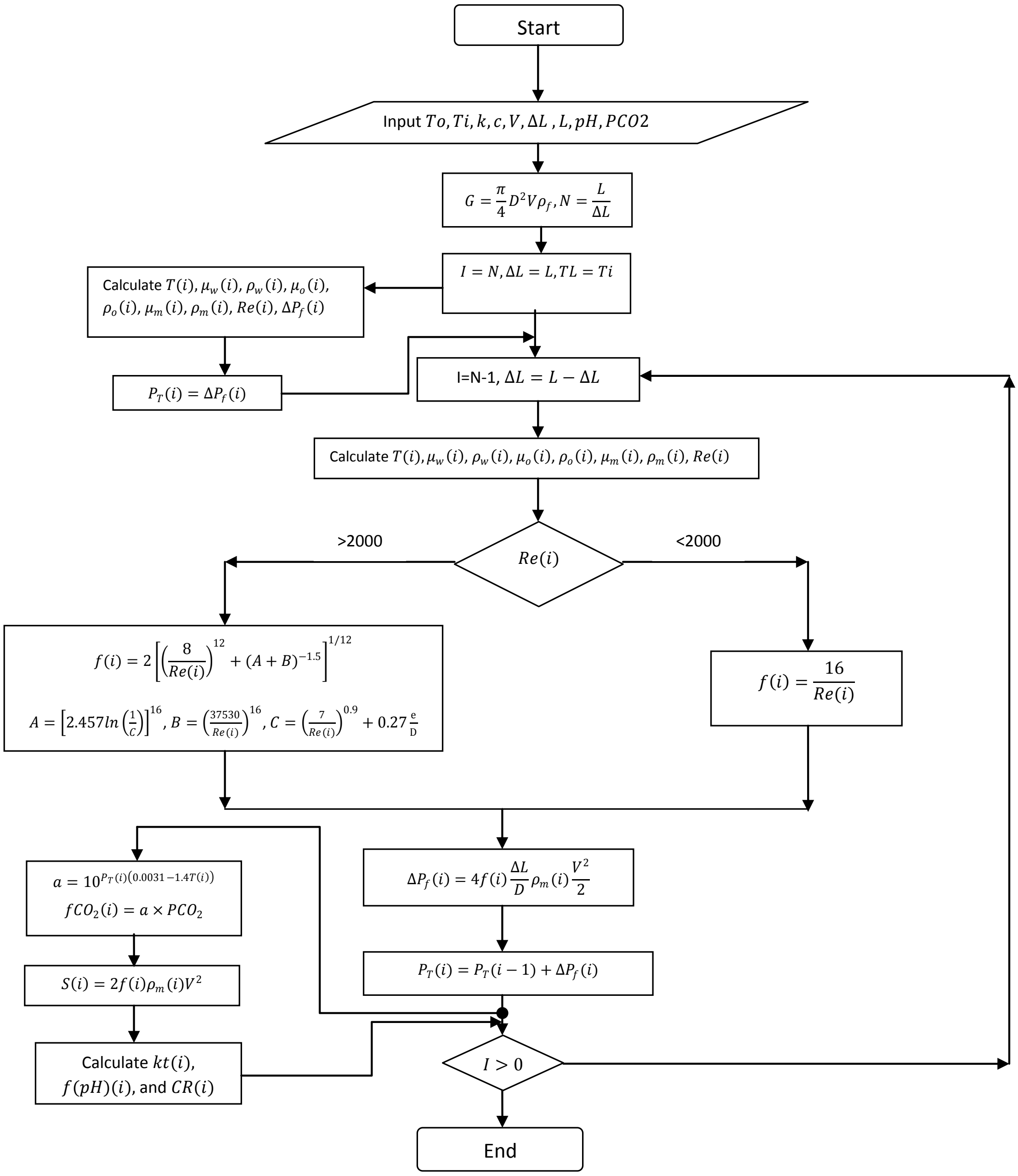

Fig 1: The simulation algorithm

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Results and discussion

A visual basic program with friendly graphical user interface has been developed following the calculation algorithm shown in figure 1. The program output includes the variation of temperature, corrosion rate, fCO_2, $f(pH)_t$, K_t Wall shear stress, Reynolds number, mixture density, and mixture viscosity along the pipeline at any conditions. The parameters in table 4 were arbitrary selected as input data to predict corrosion rate along the pipeline and analyze effects of different parameters.

Table 4: The simulation input data

Parameter	Unit	Value
Velocity	m/s	5, 1, 0.5
pH		5
CO_2 partial pressure	Bar	6
Inlet temperature	^oC	80
Soil temperature	^oC	15
Overall heat transfer coefficient	W/m^2C	2
Heat capacity	J/kgm^2	2600
Water cut	%	30
Total length	Km	200
Oil density at 20C	Kg/m^2	900
Pipe diameter	m	0.2
Roughness	m	0.0005

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Figure 2 and Figure 3 show the variation of the corrosion rate along the pipeline when the flow velocity is 5 and 1 m/s, respectively.

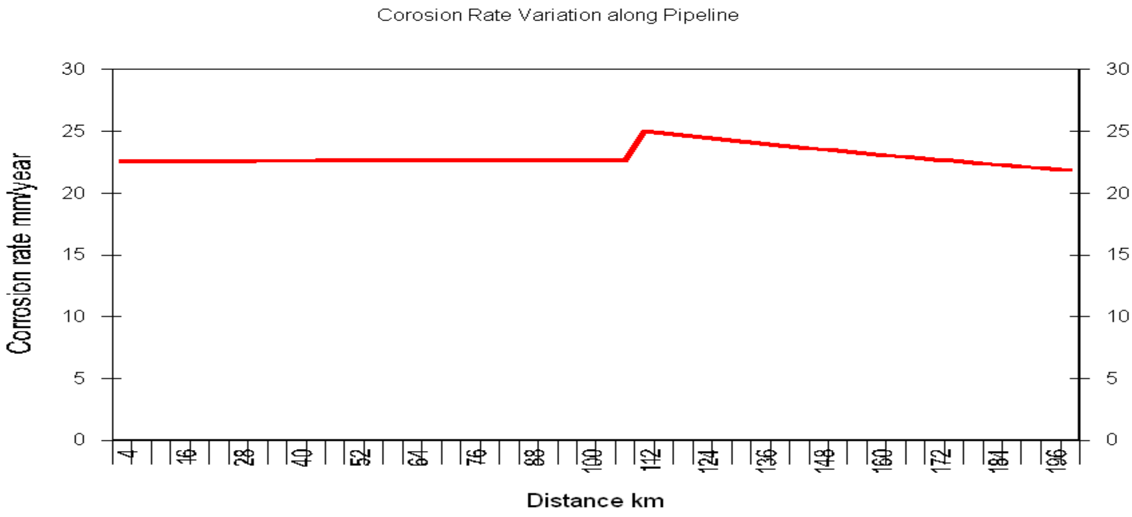

Fig 2: Corrosion rate variation along pipeline (Velocity=5 m/s)

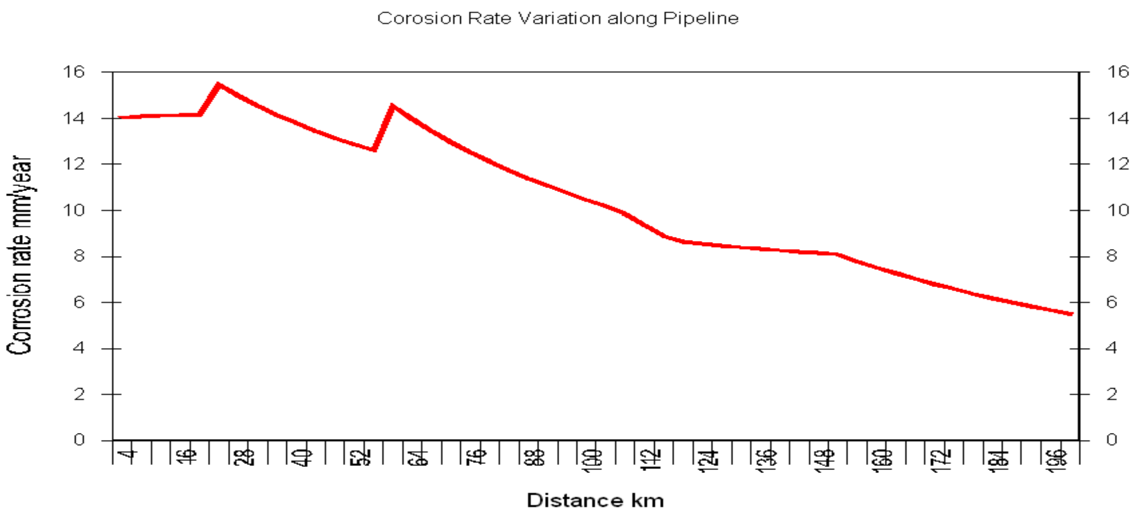

Fig 3: Corrosion rate variation along pipeline (Velocity=1 m/s)

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The comparison of Figure 2 and Figure 3 indicates that, the effect of velocity on corrosion rate is significantly high and the corrosion rate variation in the case of the higher velocity (5 m/s) is not significant. This is due to the fact that temperature declines too slowly as shown in figure 4 and the flow regime is entirely turbulent.

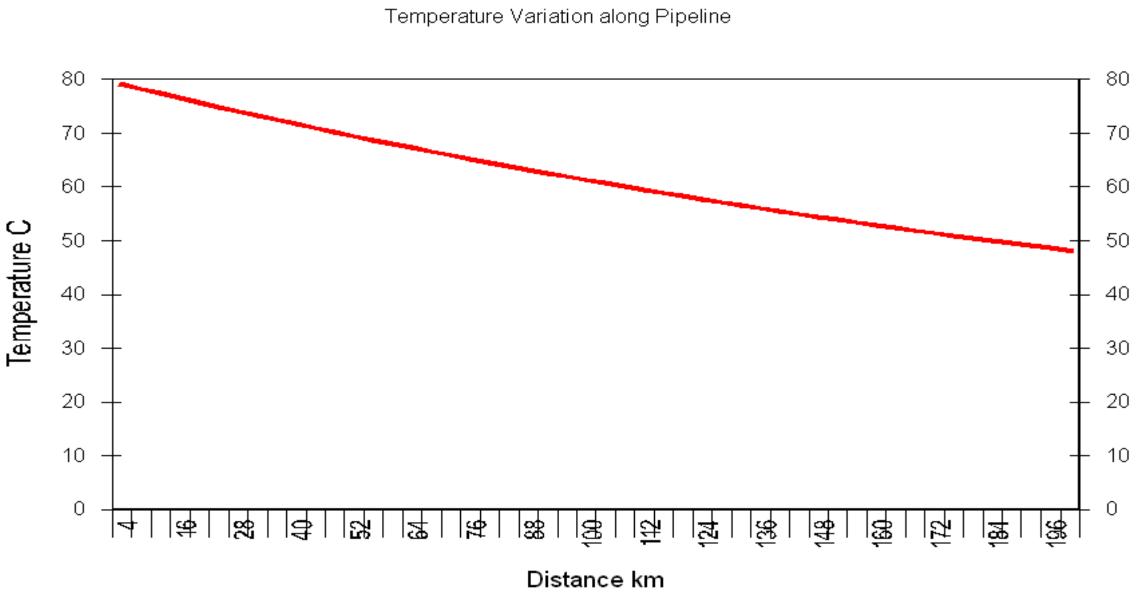

Fig 4: Temperature variation along pipeline (Velocity=5 m/s)

For the lower velocity (1 m/s) the temperature declines rapidly as shown in figure 5 which result in increasing of the flow viscosity and the flow regime is, therefore, turns from turbulent to laminar flow at distance 125 km where the Reynolds number declines to less than 2000 as shown in figure 6.

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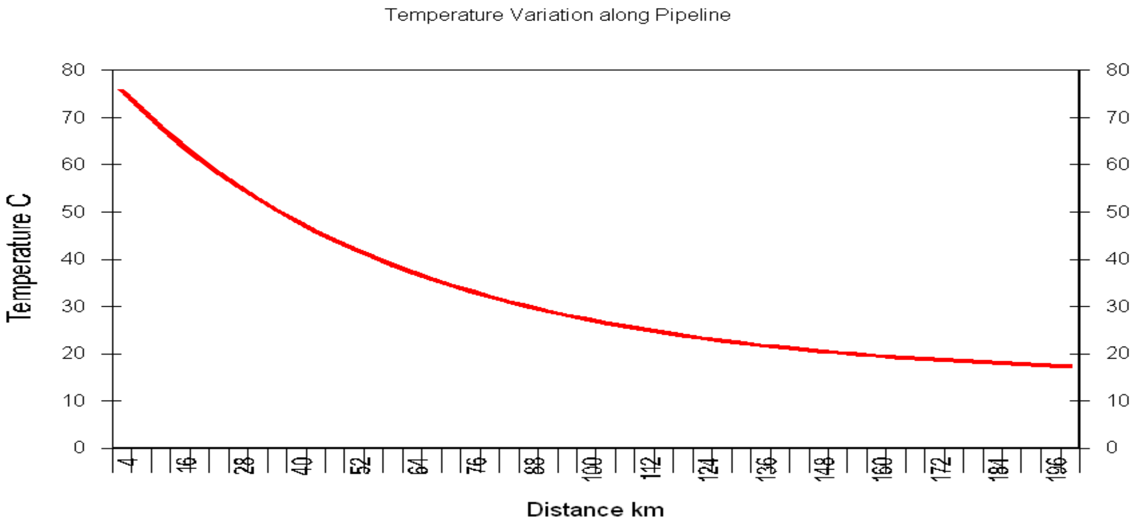

Fig 5: Temperature variation along pipeline (Velocity=1 m/s)

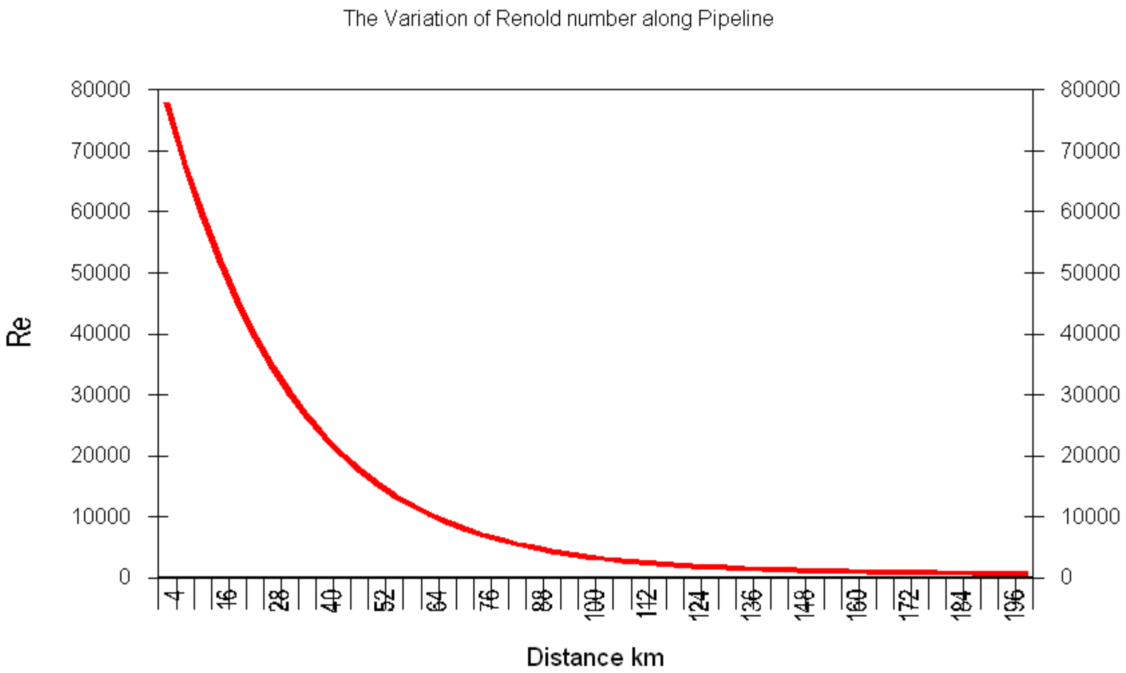

Fig 6: Reynolds No. variation along pipeline (Velocity=1 m/s)

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At flow velocity of 0.5 m/s, temperature declines more rapidly to reach the soil temperature at 140 km and the flow regime turns from turbulent to laminar at 52 km as shown in figure 7 and figure 8.

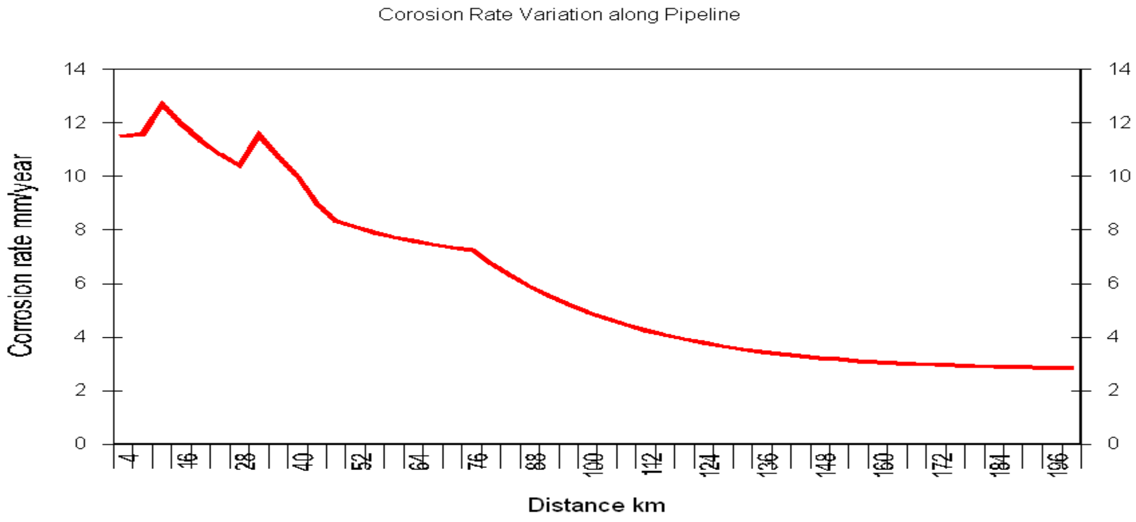

Fig 7: Corrosion rate variation along pipeline (Velocity=0.5 m/s)

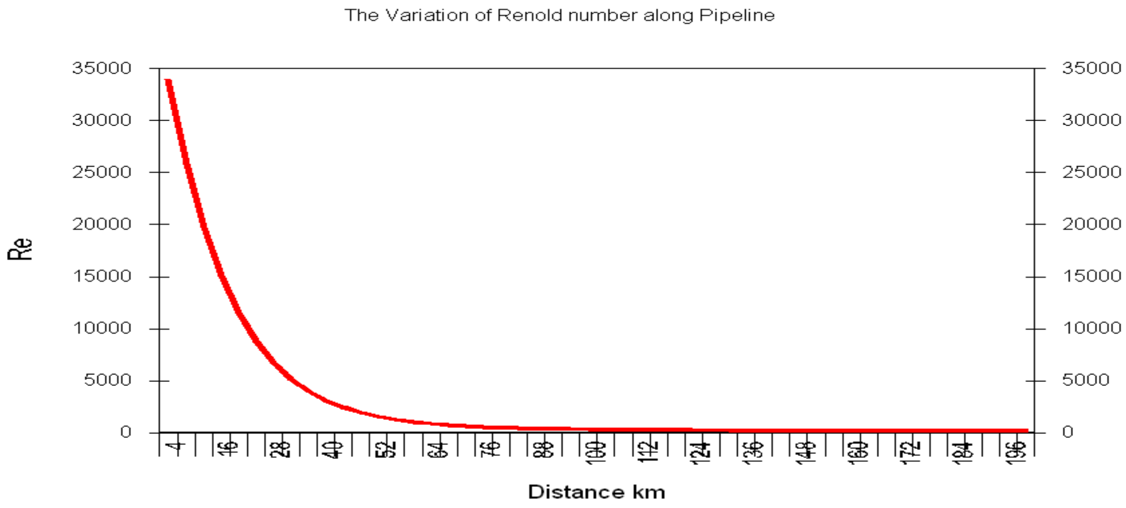

Fig 8: Reynolds No. variation along pipeline (Velocity=0.5 m/s)

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The corrosion rate, temperature, wall shear stress, and Reynolds number variation along the pipeline at the three velocities are shown in figure 9 to figure 12. From figure 9, the corrosion rate for the velocities of 1 m/s and 0.5 m/s is almost identical after the point of 152 km, where the flow regime is laminar and temperature is very low for the both cases. Figure 11 shows that the shear stress for the velocity of 0.5 m/s starts to increase dramatically after the flow regime changes to laminar at the point 52 km. This is due to viscosity increase with temperature decrease, which leads to higher friction factor; and hence, higher shears stress as in equation 19, with $\left[\frac{16\mu}{\rho VD}\right]$ is the friction factor in laminar flow.

$$S = 0.5\left[\frac{16\mu}{\rho VD}\right]\rho V^2 \qquad (19)$$

The shear stress for the velocity of 0.5 m/s continues increasing until it exceeds that of the velocity of 1 m/s at distance of 90 km and remains constant after the point 140 km, where the flow temperature reaches the surrounding temperature. At distance 125 km, the shear stress of the velocity of 1 m/s starts to increase dramatically in the same manner and continues its increase until it exceeds the shear stress of the velocity 0.5 m/s.

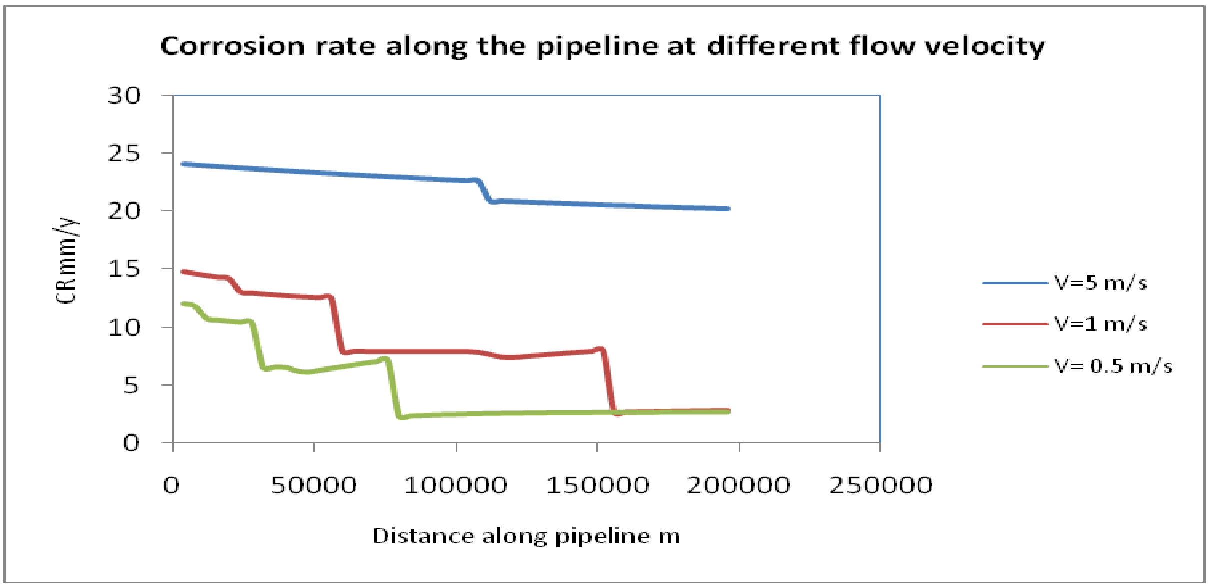

Fig 9: Corrosion rate along the pipeline at different velocities

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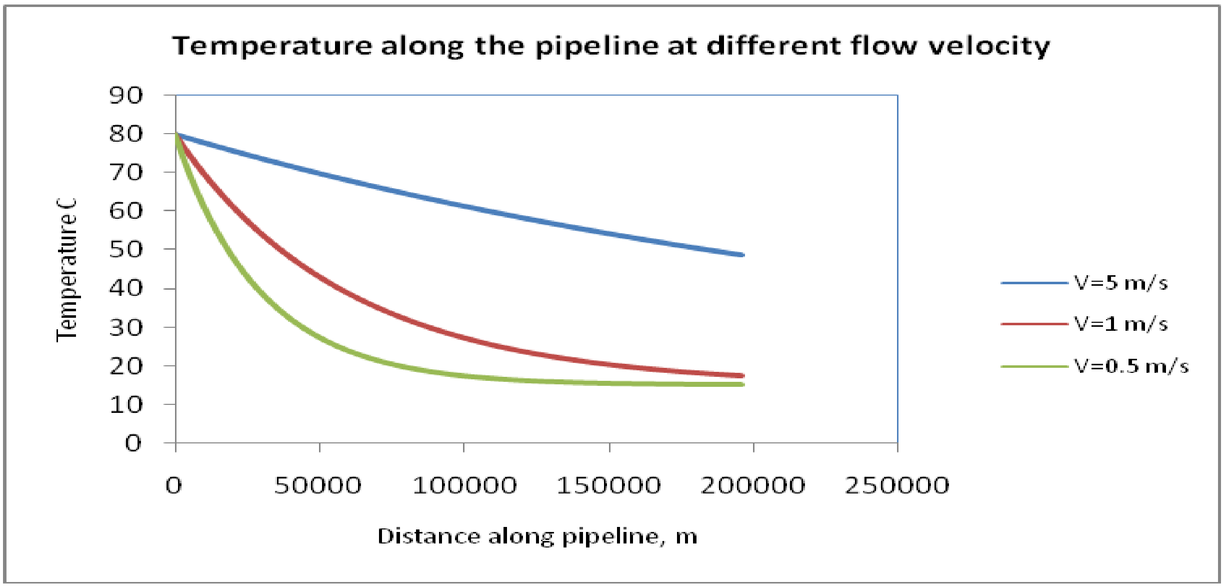

Fig 10: Temperature along the pipeline at different velocities

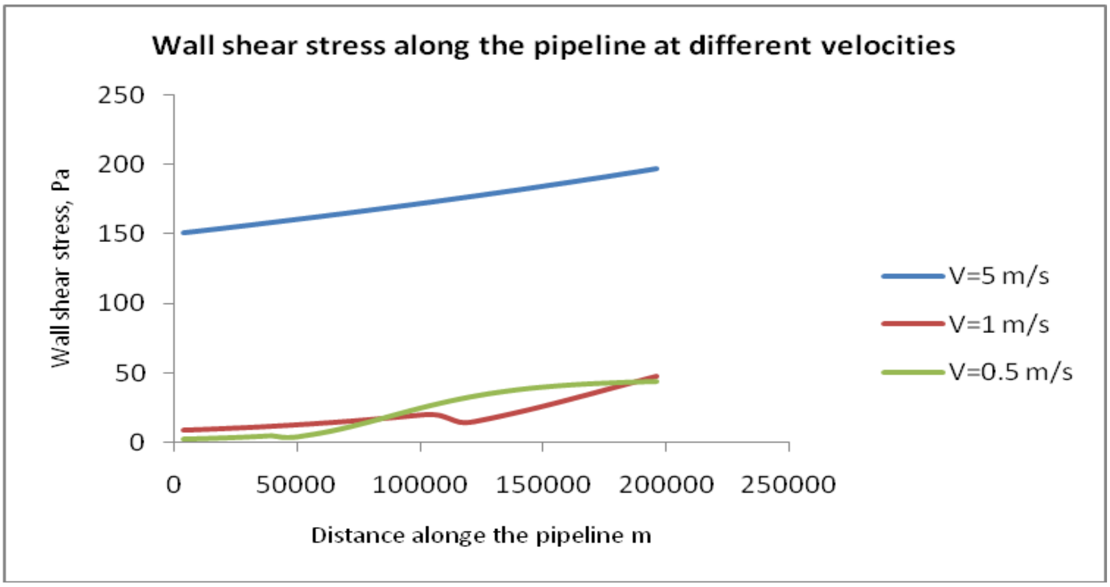

Fig 11: Wall shear stress along the pipeline at different velocities

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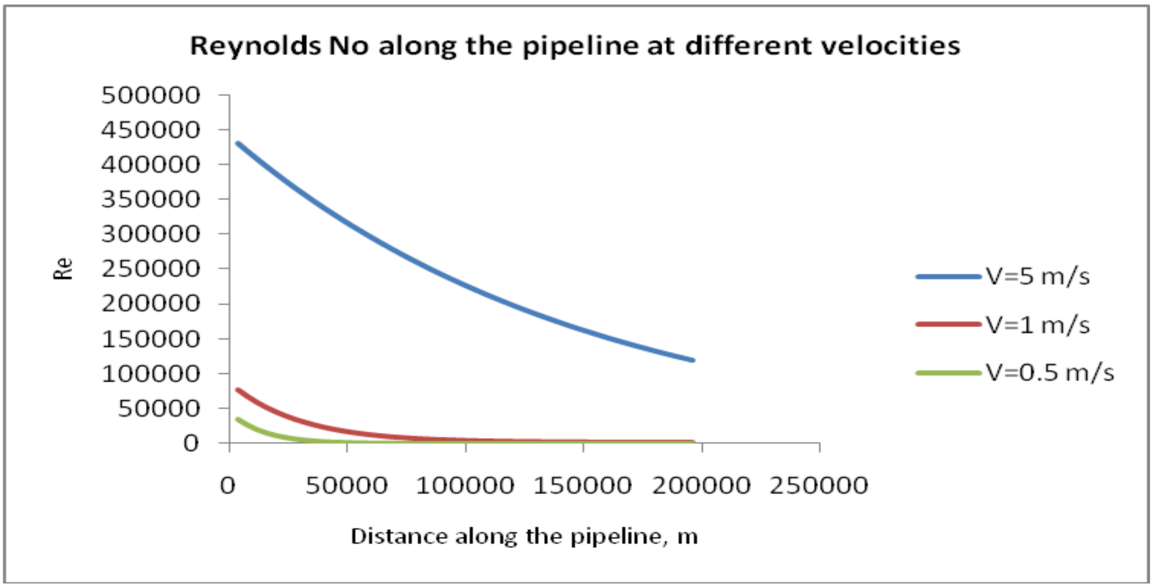

Fig 12: Reynolds No. along the pipeline at different velocities

Validation of the model

The model output were validated against data taken from (Wang, Clariant et al. 2006) for a pipeline with parameters shown in table 5.

Table 5: The field data from (Wang, Clariant et al. 2006)

Parameter	Unit	Value
Diameter	m	0.1
T	oC	66
Total pressure	Bar	287
CO_2 partial pressure	Bar	1.56
Velocity	m/s	1.18
pH		4.92

A pipeline length of 7 km was selected and the result is drawn against the single field data value given in the reference. The comparison result shown in Figure 13 indicates that the

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predicted results overestimate the field data. The accuracy of the model, however, is acceptable.

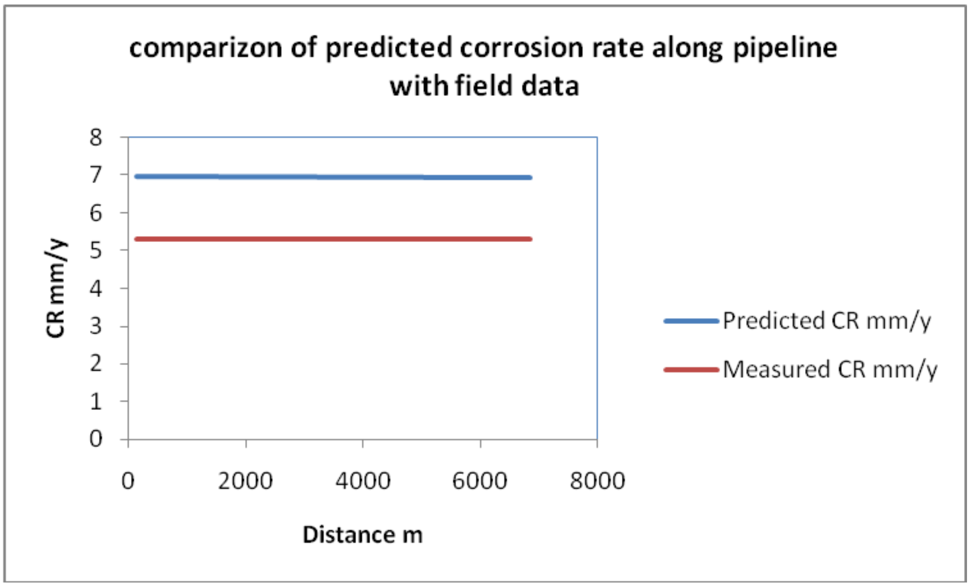

Figure 13: Validation of the model result

Conclusions

Norsok standard CO_2 corrosion prediction model has been coupled to pipelines thermal/hydraulic calculation models to simulate CO_2 corrosion rate along pipelines. A calculation algorithm has been proposed and a computational program has been developed to predict the corrosion rate and its affected factors along the pipelines at any conditions.

Pipeline operation parameters have been selected arbitrary as input data to the program and the results have been analyzed at three flow velocities.

It has been found that, flow velocity is markedly affecting the variation of thermal/hydraulic characteristics which turns on the effect on corrosion rate along the pipeline.

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At high velocity, the flow entirely exhibits turbulent regime, the corrosion rate in this case will vary slightly along the pipeline. The same thing is expected for entirely laminar flow at low velocities where corrosion rate is comparably low.

In some intermediate velocities, flow regime turns from turbulent flow to laminar flow at some distance downstream of inlet depending on the flow conditions. In this case, corrosion rate variation is more significant.

The model results were validated against published field data and acceptable agreement was indicated.

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