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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 ($CO_2$) 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 $CO_2$ corrosion prediction in straight pipes. In this paper NORSOK model has been coupled to thermal and hydraulic models to predict $CO_2$ corrosion rate along pipelines.

Keywords: Corrosion, $CO_2$, pipeline, NORSOK.

## 1. 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

## Nomenclatures

| | |
|---|---|
| $c$ | Heat capacity of fluid, J/kg°C |
| $D$ | Pipe diameter, m |
| $fCO_2$ | Fugacity of $CO_2$ (Eq. 2), bar |
| $f(\mathrm{pH})_t$ | pH factor at a temperature $T$ (Eq. 2) |
| $G$ | API gravity |
| $g$ | Gravidity acceleration, m/s$^2$ |
| $K_t$ | Temperature dependent constant (Eq. 2) |
| $K_{tot}$ | Overall heat transfer coefficient, W/m$^2$°C |
| $L$ | Distance, m |
| $P_{CO_2}$ | $CO_2$ partial pressure, bar |
| $p_f$ | Friction pressure, Pa |
| $R_c$ | Corrosion rate, mm/year |
| $Re$ | Reynolds number |
| $S$ | Wall shear stress, Pa |
| $SG$ | Specific gravity |
| $T$ | Temperature, °C |
| $T_i$ | Inlet temperature, °C |
| $T_L$ | Temperature at distance $L$ along pipeline, °C |
| $T_o$ | Pipeline surrounding temperature, °C |
| $V$ | Fluid velocity, m/s |

*Greek Symbols*

| | |
|---|---|
| $\mu$ | Viscosity, Pa.s |
| $\rho$ | Density, kg/m$^3$ |

*Subscripts*

| | |
|---|---|
| $m$ | Mixture |
| $o$ | Oil |
| $t$ | Total |
| $w$ | Water |

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 [1-4].

Nešić et al. [5] developed a comprehensive model for internal corrosion prediction in mild steel pipelines. The effects of many factors contribute to corrosion rate such as $H_2S$, 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 couples a dynamic model for flow regime prediction to mechanistic and semi-empirical models for corrosion prediction [6-7].

In this paper an empirical model developed by NORSOK Norwegian standard [8] for prediction of $CO_2$ corrosion in straight pipes has been coupled to selected models for pipelines thermal/hydraulic calculations to simulate $CO_2$ corrosion rate along oil pipelines.

## 2. 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 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 [9]:

$$T_L = T_0 + (T_i - T_0)e^{-\left(\frac{K_{tot}\pi D}{Gc}\right)L} \tag{1}$$

where, $T_i$ is the inlet temperature, $T_o$ is the surrounding temperature, $K_{tot}$ is the overall heat transfer coefficient (a function of the fluid heat convection factor and the pipe and coating heat conduction factor), $c$ is the heat capacity of the fluid.

$G$ is the mass flow rate of the fluid kg/s, which is related to fluid velocity as follows: $G = \frac{\pi}{4}D^2V\rho_f$

where $\rho_f$ is the fluid density, $V$ is the fluid velocity and $D$ is the pipe diameter.

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, Eq. (2) [8], $CO_2$ corrosion within temperature range of 20 to 120ºC can be calculated using the following empirical equation:

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

where $K_t$ is a temperature-related constant its values are listed in [8] for temperatures from 5 to 150ºC, $f$(pH) is a factor depending on the pH of the solution. NORSOK [8] introduced a list of empirical models for calculating this factor at different temperatures and ranges of pH.

From Eq. (2), $CO_2$ corrosion depends on four factors that in turn depend on temperature. These factors can be summarized as shown in Table 1.

Equation (1) is used to calculate temperature distribution along the assuming constant overall heat transfer coefficient and surrounding temperature. The calculated temperatures can then be used to calculate shear stress, fugacity, pH, and $k_t$ at the respective points, and hence, corrosion rates are calculated using Eq. (2).

**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 60ºC and then decreases up to 150ºC | Decreases 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 (The $CO_2$ partial pressure ( $P_{CO_2}$ ) is assumed constant). $fCO_2 = a \times P_{CO_2}$ $a = 10^{P(0.0031-1.4T)}$ |
| $S$ | Wall shear stress | Increases with viscosity and density which in turn decreases with temperatures. | Increases with distance |
| $f(\mathrm{pH})_t$ | The effect of pH at any temperature | As tabulated by NORSOK [8] | Increases with distance |

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 system (oil, water).

The density and viscosity of water at any temperature $T$ is calculated as follows (assuming the water density at 20ºC is 998.2 kg/m$^3$):

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

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

The oil density at any temperature $T$ is calculated as follows [9]:

$$\rho_o(T) = \rho_{20} - (1.825 - 0.001315\rho_{20})(T-20) \tag{5}$$

where $\rho$ and $\mu$ are density (kg/m$^3$) and viscosity (cp) and the subscripts $o$ and $w$ denote oil and water respectively and $\rho_{20}$ (kg/m$^3$) is the oil density at 20ºC.

Beggs and Robinson [10] correlations are used for viscosity prediction at any temperature $T$. these correlations are as follows:

The viscosity, $\mu_o(T)$, at temperature, $T$, is given as

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

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

API gravity can be obtained from the following correlation

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

where $SG$ is the specific gravity of oil.

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

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

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

where $WC$ is water cut (%).

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

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

where $V$ is the flow velocity (m/s) and $D$ is the pipe diameter (m).

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

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

In the case turbulent flow regime ($\mathrm{Re}(T) > 2000$), friction factor is calculated using Churchill [11] model as follows

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

where $A$, $B$, and c are given in Eqs. (12)-(14)

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

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

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

and $e$ is the pipe roughness (m).

The friction factor is introduced to Darcy-Weisbach equation as follows [9] to calculate the pressure losses drop ($\Delta P_f$) in Pascal as follows:

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

where $\Delta L$ is the pipe length (m).

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

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

and the pressure at the $M^{th}$ interval $T$ is calculated using the following equation

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

The wall shear stress (in Pascal) at any temperature $T$ is calculated using the following equation:

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

The calculation procedure is shown in Fig. 1.

## 3. Results and Discussion

A visual basic program with friendly graphical user interface has been developed following the calculation algorithm shown in Fig. 1.

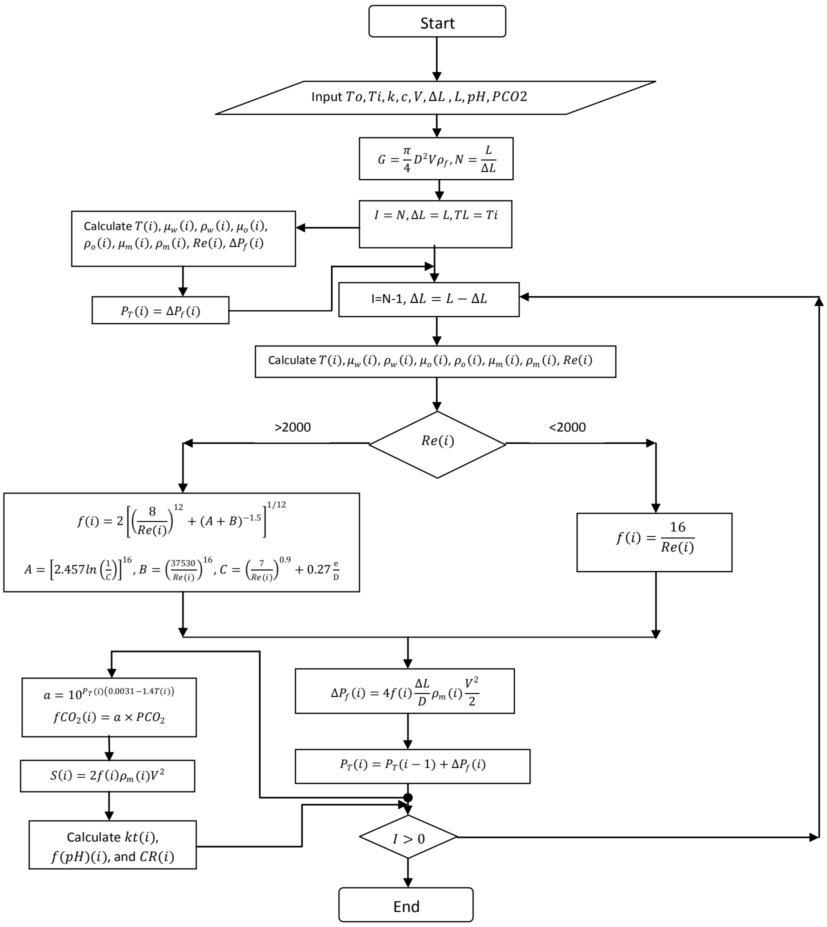


**Fig. 1. The Simulation Algorithm.**

Figure 2 shows the input data form of pipeline simulation. Other required input data are entered in another corrosion input data from, from which the user can navigate to this form. From the form prediction of corrosion rate, temperature, Fugacity, *f*(pH), wall shear stress, Reynolds number, mixture viscosity, and mixture density can be obtained as output in tabular or graphical form.

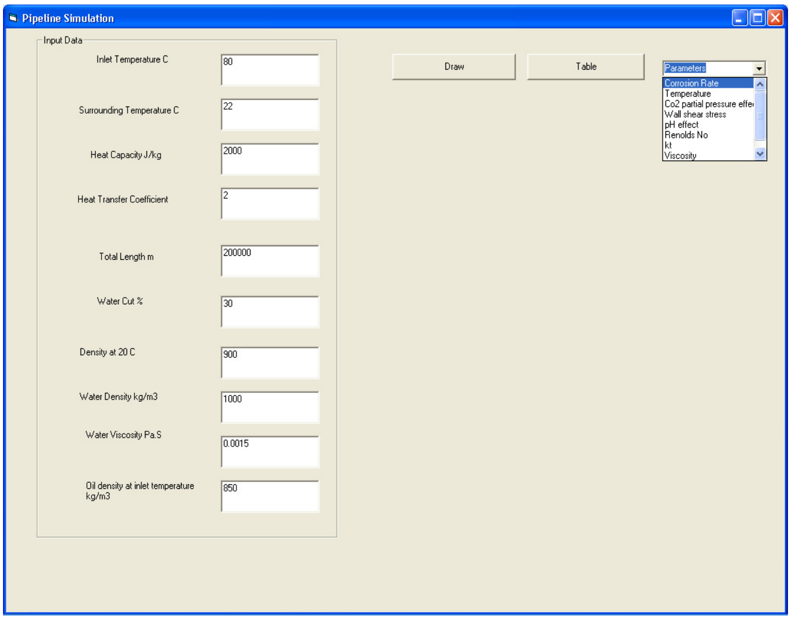


**Fig. 2. Input Data Form of Pipeline Simulation.**

The program output includes the variation of temperature, corrosion rate, $fCO_2$, $f(\mathrm{pH})_t$, $K_t$ Wall shear stress, Reynolds number, mixture density, and mixture viscosity along the pipeline at any conditions. The parameters in Table 2 were arbitrary selected as input data to predict corrosion rate along the pipeline and analyze effects of different parameters.

**Table 2. The Simulation Input Data.**

| Parameter | Unit | Value |
|---|---|---|
| Velocity | m/s | 0.1, 0.3, 0.5 |
| pH | -log ($H^+$) concentration | 4 |
| Inlet temperature | $^{o}$C | 70 |
| Soil temperature | $^{o}$C | 20 |
| Overall heat transfer coefficient | $W/m^{2o}C$ | 2 |
| Heat capacity | $J/kgm^2$ | 3600 |
| Water cut | % | 70 |
| Total length | km | 100 |
| Oil density at 20$^{o}$C | $kg/m^3$ | 900 |
| Pipe diameter | m | 0.2 |
| Roughness | m | 0.0005 |

Figure 3 shows the variation of corrosion rate along the pipeline at different flow velocity. It is clear that the corrosion rate decreases along the pipeline. The degree of declination is, however, decreases with the increase of flow velocity. This because of the fact that at higher velocity more heat is generated which compensates part of the heat lost due to heat transfer between the transported fluid and surroundings. That is to say, higher velocity leads to higher temperature as compare to that result from lower velocity. As temperature, normally, increases corrosion rate, less declination of corrosion rate results from higher velocity.

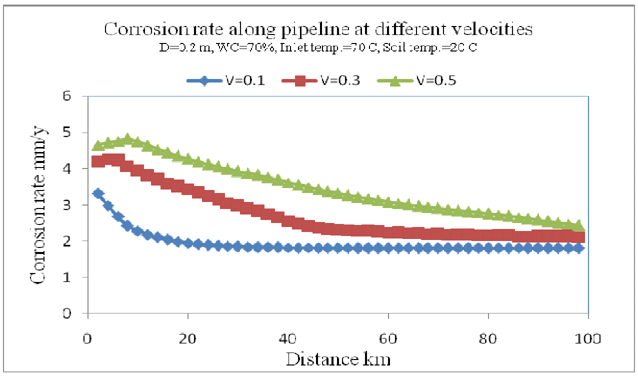


**Fig. 3. Variation of Corrosion Rate along Pipeline at Different Velocities.**

The variation of temperature along the pipeline using the same input data is shown in Fig. 4. At flow velocity of 0.1 m/s temperature declines very fast to reach the surrounding temperature at 36 km and remain constant. Therefore, the corrosion rate at this velocity, from Fig. 3, reaches the minimum value at this distance and remains constant until the pipeline terminal.

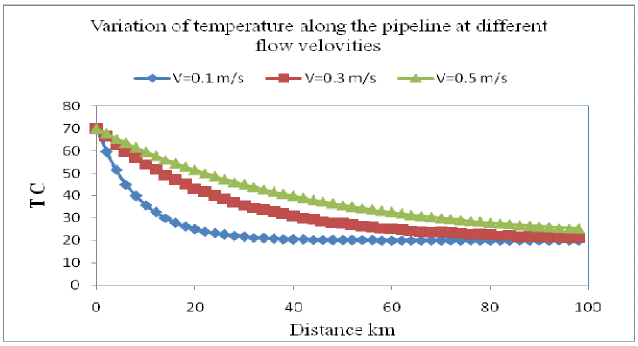


**Fig. 4. Variation of Temperature along Pipeline at Different Velocities.**

The variations of mixture density and mixture viscosity along the pipeline are shown in Figs. 5 and 6, respectively. Both density and viscosity increase with distance due to temperature declination. This results in increasing shear stress which turn in increase in corrosion rate (as indicated in Eq. (2)). From Fig. 3, the overall effect is the decrease of corrosion rate along the pipeline. It means that the contribtion of the corrosion-related parameters ($K_t$, $CO_2$ partial pressure, and pH) predominantes over the effect of flow-related parameters (viscosity and density).

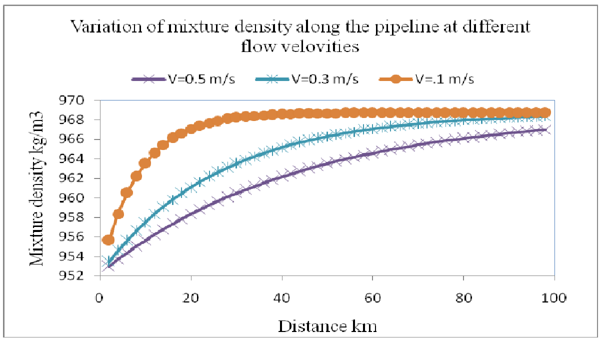


**Fig. 5. Variation of Mixture Density along Pipeline at Different Velocities.**

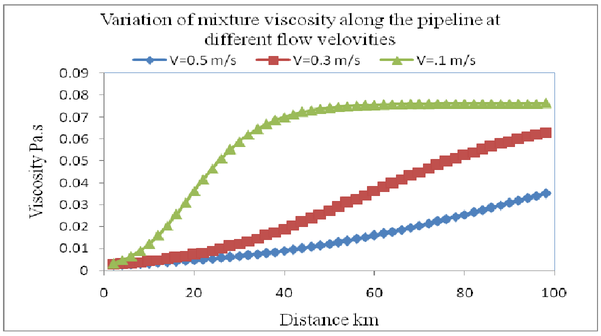


**Fig. 6. Variation of Mixture Viscosity along Pipeline at Different Velocities.**

## 4. Validation of the Model

The model results were validated against data taken from [12] for a tubing transporting oil and water. The reported field data is in the range of 4.4 to 10 mm/year with no details about the corrosion rate at each point and the length of tubing. We assume a short length to guarantee no change in temperature.

The predicted results in Table 3 are almost within the range of the reported field data. These results do not reflect a real validation as the code is applicable to horizontal pipelines and the data is taken from vertical tubing. The difference, however, is only due to the effect of potential pressure in tubing which increases the total pressure. This will only affect the $CO_2$ fugacity.

**Table 3. The Tubing Predicted Corrosion Rate.**

| $T$ (°C) | $P$ (bar) | $P_{CO_2}$ (bar) | $Q_t$ m³/d (*V m/s) | $D$ (m) | pH | $WC$ (%) | CRp |
|---|---|---|---|---|---|---|---|
| 57 | 270 | 1.56 | 800 (1.18) | 0.1 | 5.05 | 5 | 5.42 |
| 80 | 250 | 1.56 | 1220 (1.8) | 0.1 | 5.05 | 5 | 6.776 |
| 85 | 269 | 1.56 | 1220 (1.8) | 0.1 | 5.1 | 47 | 3.775 |

* Calculated value

## 5. 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 in turns on affects the corrosion rate along the pipeline. At low velocities, temperature declines rapidly to reach the surrounding temperature short distance after the pipeline inlet to remain constant until the terminal point. At high velocities the temperature, most probably, remains above the surrounding temperature until the terminal point. The variation of temperature along the pipeline has double effect on the corrosion rate variation along the pipeline. The flow related parameters (viscosity and density) increases with the temperature decrease. This leads to increase of shear stress along the pipeline which turns in increasing corrosion rate. The corrosion-related parameters ($K_t$, $CO_2$ partial pressure and pH) decreases with temperature decreases which leads to decrease of corrosion rate along the pipeline.

From the mdel results, it has been found that corrosion rate always decreases along the pipeline. It means that the contribtion of the corrosion-related parameters predominantes over the effect of flow-related parameters.The model results were validated against published field data and acceptable agreement was indicated.

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