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Comparative Performance Of Hydrate Pressure And Temperature Prediction Models Along Crude Oil Transmission Pipeline

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ABSTRACT
This study presents the comparative performance of hydrate pressure and temperature prediction model along crude oil transmission pipeline in Usan Oil Field, Rivers State, Nigeria.Computational fluid dynamic model was utilized to simulate the fluid parameter (pressure, temperature and flow-rate) along the pipeline in MATLAB domain. PIPESIM software was then utilized to compare the simulated results obtained. 9,875.52m, 0.228m/s, 289.51K and 68.95 bar were the input parameters for the pipeline length, fluid velocity, inlet temperature and inlet pressure, respectively, while the flow rate and fluid density were kept constant at 1000 STB/d and 828.5 kg/m³, respectively.The results indicate that both pressure and temperature decreased along the length of the pipe, indicating frictional losses and obstructions from scales and potential hydrate formation. The pressures and temperatures predicted by the PIPESIM were observed to be higher than the values computed by the model, hence, demonstrated a better correlation. The RMSEvalue computedbetween the software and the model are 0.15823and 0.025995 for predicted pressure and temperature, respectively. The comparative analysisof the PIPESIM and the model-generated values for the fluid temperature and pressure reveals that both techniques can be used to study hydrate formation in crude oil transmission pipelines. The results for both techniques demonstrated that hydrate formation is more likely to occur when the pressure drop along the pipeline is minimal and when the changes in fluid pressure and temperature are low. Overall, this study provides insights on the state of hydrate formation under specific pressure and temperature conditions. This study further demonstrated that both models can beused to predict the temperature distribution and pressure changes in crude oil transmission pipelines as well as to analyse the conditions for hydrate formation.
KEYWORDS: *PIPESIM, Model, Hydrate, Pressure, Temperature, Crude Oil Pipeline*

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I. INTRODUCTION

Normally, crude oil and natural gas are transported through long-distance pipelines to terminal stations, where they can be gathered for further use or sales. These pipelines,in most cases, pass through subsea. The transporting of liquidsand gases via pipes is associated with some technical challenges due to changes in the water or system properties, therebyleading to the formation of hydrates (Zuo et al., 2021). This scenario undermines the safety and flow assurance of the system, leading to flow restrictions, blockages, and accident (Li et al., 2012).

The formation of hydrate in a crude oil and gas transmission pipe is dependent on several factors like dew point, humidity, compositions of the fluid, density and flow rate (Cao et al., 2020). These factors affect the pressure, temperature and velocity of the flowing fluid. Sloan and Koh (2008) provided an in-depth understanding of Clathrate hydrates, including their formation, properties, and impact on pipeline flow. Also, Sun and Yang (2015) highlighted onsome flow properties that constitute a challenge to flow assurance in the petroleum industry.

Modelling the flow of crude oil in subsea pipelines is crucial for predicting and monitoring various aspects of a pipeline operation, including the formation of hydrate (Davitashvili, 2021) Hydrate is an ice-like solid that is formed when water combines with gases under specific pressure and temperature conditions (Guimin et al., 2022). However, as a way of monitoring hydrate formation pressure and temperature, researchers have developed various modelling approaches which predict the conditions under which hydrates may form. It alsohelps in devising preventive measures against formation of hydrate and improving flow assurance.For instance, thethermodynamic fluid flow properties and phase behaviour of fluid mixture have been studied using thermodynamic models, such as the Peng-Robinson or the Soave-Redlich-Kwong equations of state (Khosravani et al., 2013; Zuo et al., 2021;Saeed &Emamzadeh, 2021). These equations describe the relationship between pressure, temperature, and composition of the oil-gas-water system, allowing for the estimation of hydrate formation conditions.

Computational fluid dynamics (CFD) models are also employed to simulate fluid flow inside the pipeline, by considering factors such as flow rate, pipe geometry, and boundary conditions. CFD models can help in identifying regions of potential hydrate formation by calculating the temperature and pressure distribution along the pipeline (Davitashvili, 2021;Guimin et al., 2022).

Another modelling approach is the use of artificial intelligence (AI) and machine learning (ML). Recent advancements in AI and ML techniques have shown promise in predicting hydrate formation conditions (Matko et al., 2000). These models utilize data-driven approaches to capture complex relationships between input parameters and hydrate formation behaviour. Examples of AI/ML models include neural networks, support vector machines, and random forests, which their application have been reported successful for hydrate prediction (Cao et al., 2020). These models can incorporate a wide range of input parameters, including fluid composition, flow conditions, and environmental factors, to improve prediction accuracy. Mesbah et al. (2017) proposed a machine learning-based approach for predicting hydrate formation conditions in subsea pipelines. A model was developed using support vector machine (SVM), which was used to train a large dataset of experimental data. The SVM model demonstrated good accuracy and computational efficiency, making it a promising tool for practical applications. Another recent study used the artificial neural networks (ANN) technique to study and predict temperature and pressure of a multiphase gas flow system and the kinetics of gas hydrates formation (Shaik et al., 2022).

Empirical models can also be used to correlate the system temperature from the knowledge of the pressure of the flowing fluid at any position in the pipe. These types of models are developed based on experimental data and regression analysis. The data are used to correlate hydrate formation conditions with various input parameters such as temperature, pressure, salinity, and composition of the fluid. The advantage of empirical models is their simplicity and ease of use. However, they may have limitations in terms of accuracy and applicability to a wide range of operating conditions. Several empirical equations and data-driven models have been proposed in the literature for prediction of hydrate formation in oil gas transmission facilities (Hashim& Abbasi, 2016; Mehrizadeh, 2021).

Computational fluid dynamics (CFD) have previously been applied to study the pressure and temperature characteristics of crude oil or gas in transporting pipelines. For instance, CFD models were used to simulate and predict fluid temperature and pressure distribution at any position in the pipeline, through which they identified the regions of potential hydrate formation (Davitashvili, 2021; Guimin et al., 2022).This study highlight the importance of modelling in monitoring of hydrate formation conditions in subsea pipelines used for transporting of crude oil and gas. In addition, the studies showed the importance of temperature and pressure as key indices for determining the formation of hydrate. Software like; PIPESIM simulator, CSM Gem, Multi-Flash simulator, PVTsim simulator have been used for hydrate prediction in the petroleum industry. However, there are limited studies on comparison of predicted pressure and temperature by software like PIPESIM with computational fluid dynamic models to ascertain their level of agreement at the same operating conditions. Therefore, this study presents the comparative performance of hydrate pressure and temperature prediction model along crude oil transmission pipeline in Usan Oil Field, Rivers State, Nigeria. It compared the fluid parameter (pressure, temperature and flow-rate) obtained fromUsan Oil Field crude oil pipeline using PIPESIM software and computational fluid dynamic (CFD) model.

II. Materials and Methods

The formation of hydrate in a crude oil and gas transmission pipe depends on several factors, but pressure and temperature of the crude oil transmision pipe was modelled to study the condition for which hydrate can form. First, the modelling was carried out using a developed software called PIPESIM, which is designed for asimulation of multiphase flow. Secondly, established models used for the study of hydrate formation in transmission pipes is used to predict the pressure and temperature of the crude oil along the pipes. The predicted pressures and temperatures were compared to ascertain the level error between the two modelling approaches.

Hydrate formation modeling

However, models have been developed to study the eeffects of these variables onthe formation of hydrate in pipes.The well known models for monitoring and simulation of hydrate formation in oil and gas transmission pipes have been developed to depend on time and pipe dimension (diameter or length). According to Matko et al. (2000), the basic parameters that are simultaneously modelled for a non-steady state flow and non-isothermal systems include the fluid velocity, pressure, temperature, or density. The basic equations are stated as follows:

$$\frac{\partial V}{\partial t} = -\frac{1}{\rho_o}\frac{\partial P}{\partial L} + v_O \frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial V}{\partial r}\right) \quad (1)$$

$$\frac{\partial P}{\partial t} = \rho_o C_p \left(1 - \frac{C_p}{C_v}\right)\frac{\partial T}{\partial t} - \rho_o C^2 \frac{C_v}{C_p}\frac{\partial V}{\partial L} \quad (2)$$

$$\frac{\partial T}{\partial t} = -\frac{1}{\rho C_p}\frac{\partial P}{\partial t} + \alpha \frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right) \quad (3)$$

$$\frac{\partial \rho}{\partial t} = -\rho_o \frac{\partial V}{\partial L} \quad (4)$$

where:
P = Gas pressure
T = Gas temperature
v = Gas velocity
$\rho_o =$ Gas density in normal condition
α= Gas heat conduction coefficient
C_p= Specific heat capacity at constant pressure
$C_v =$ Specific heat capacity at constant volume
C = Speed of sound propagation in gas
r = Radius of pipe
L = Length of pipe
t = time

It has been shown that for adiabatic flow, the ratio of the flowing fluid pressure to its density is given by (Davitashvili, 2021):

$$\frac{P}{\rho} = C^2 \quad (5)$$

Hence by substituting equation (5) into equations (3) and (4), a new set of equations were obtained as:

$$\frac{\partial T}{\partial t} = -\frac{C^2}{C_p}\frac{1}{P}\frac{\partial P}{\partial t} + \alpha \frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right) \quad (6)$$

$$\frac{\partial}{\partial t}\left(\frac{P}{C^2}\right) = -\rho_o \frac{\partial V}{\partial L} \quad (7)$$

$$\frac{\partial P}{\partial t} = -C^2 \rho_o \frac{\partial V}{\partial L} \quad (8)$$

Substituting the equivalent of $\frac{\partial P}{\partial t}$ in equation (8) into equation (7), we obtain:

$$\frac{\partial T}{\partial t} = \frac{C^4}{C_P}\frac{\rho_O}{P}\frac{\partial V}{\partial L} + \alpha \frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T}{\partial r}\right) \quad (9)$$

Since the fluid flow along the radial direction is insignificant, the changes in fluid velocity, pressure and temperature along the pipe radius are neglected (i.e. $\frac{\partial V}{\partial r} = 0$; $\frac{\partial P}{\partial r} = 0$; $\frac{\partial T}{\partial r} = 0$). Hence, equations (1) and (9) reduced to:

$$\frac{\partial V}{\partial t} = -\frac{1}{\rho_o}\frac{\partial P}{\partial L} \quad (10)$$

$$\frac{\partial T}{\partial t} = \frac{C^4}{C_P}\frac{\rho_O}{P}\frac{\partial V}{\partial L} \quad (11)$$

Equations (8), (10) and (11) are used to obtain the pressure, temperature and velocity of the fluid at any position along the pipe.

The initial conditions are given as

$$v(L,0) = v_0(L); P(L,0) = P_o(L); T(L,0) = T_0(L) \quad (12)$$

The results obtained from the model and PIPESIM were compared using the root mean-square error (RMSE) stated in equation (13).

$$RMSE = \sqrt{\sum_{i=1}^{N} \frac{(y_{PIPESIM} - y_{MODEL})^2}{N}} \quad (13)$$

where: $y_{PIPESIM}$ = Predicted pressure or temperature along the pipeline using PIPESIM
y_{MODEL} =Predicted pressure or temperature along the pipeline using the model
N =Number of positions along the pipeline

The RMSE value was also multiplied by 100% to estimate the percentage of error or deviation between the two predicted pressures and temperatures (see table 1)

Table 1: Model and PIPESIM Input parameters

Input parameter	Value	Unit
Fluid inlet pressure, P	68.948	bar
Fluid temperature, T	16.511	ºC
Design production rate	1000	STB/d
Pipe inner diameter	0.203	m
Wall thickness	0.0071	m
Horizontal distance, L	9875.52	m
Speed of sound propagation in gas, C	300	m/s
Fluid density	828.5	kg/m^3
Fluid velocity	0.228	m/s
Specific heat capacity	2.1	kJ/kg.K
Simulation time	3600	s

III. Results and Discussion

In order to examine the equilibrium state of the multiphase flow, a subsea pipeline with a length of 9,875.52 meters with an inner diameter of 0.203 metres and a wall thickness of 0.0071 metres was considered. A stratified liquid flow pattern was assumed. The simulation was performed using inlet temperature and pressure of 289.51K and 68.95barg at initial fluid velocity of 0.228 m/s, constant flow rate of 1000STB/d and constant fluid density of 828.5 kg/m^3.

Table 2: Predicted pressure (barg) and temperature of (K)

	Predicted pressure (barg)		Predicted temperature (K)	
Length of pipeline (m)	PIPESIM	Model	PIPESIM	Model
0	68.94785	68.94785	289.511	289.511
487.68	68.81456	68.67193	289.5	289.421
975.36	68.68109	68.47686	289.489	289.4
1463.04	68.54743	68.28178	289.477	289.382
1950.72	68.41358	68.08671	289.466	289.365
2438.4	68.27954	67.89164	289.455	289.35
2926.08	68.14531	67.69657	289.443	289.336
3413.76	68.01088	67.5015	289.432	289.323
3901.44	67.87625	67.30642	289.421	289.31
4389.12	67.74141	67.11135	289.408	289.297
4876.8	67.60637	66.91628	289.395	289.284
5364.48	67.47112	66.72121	289.382	289.27
5852.16	67.33565	66.52614	289.369	289.255
6339.84	67.19998	66.33106	289.356	289.239
6827.52	67.06408	66.13599	289.342	289.221
7315.2	66.92796	65.94092	289.329	289.201
7802.88	66.79162	65.74585	289.316	289.178
8290.56	66.65505	65.55078	289.303	289.152
8778.24	66.51826	65.3557	289.289	289.124
9265.92	66.38122	65.16063	289.276	289.091
9753.6	66.24396	64.96556	289.263	289.055
9753.6	66.24396	64.96556	289.256	289.051
9814.56	65.42853	64.94118	289.245	289.05
9875.52	64.62061	64.91679	289.225	289.045

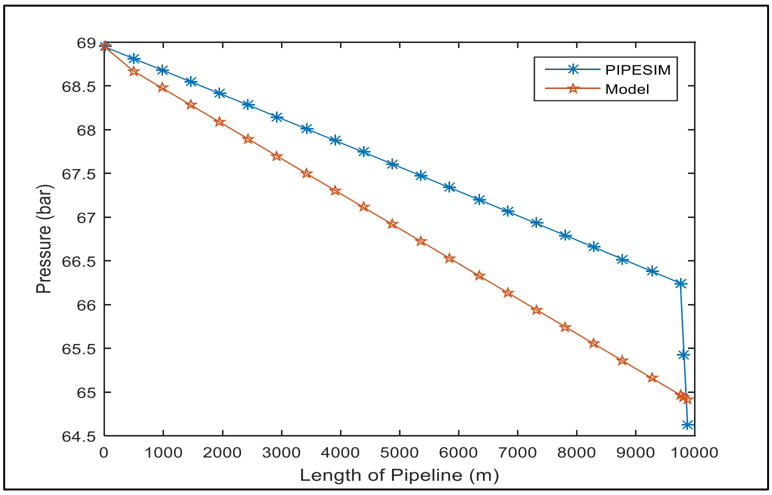

Figure 1: Comparison of pressure profile generated from PIPESIM and the model

Figure 1 shows the predicted pressure profiles at various positions in the pipeline. As illustrated, the pressure drop relatively followed a linear trend, which is a driving mechanism for the change in other variables like volume fractions or velocities (Qasim et al., 2019; Guimin et al., 2022). The pressure change is an indication of pressure drop, which occurred due to friction on the walls of the pipe and obstructions from developing scales and particles with potentials to form hydrates. The PIPESIM results in Figure 1 indicated that towards the end of the pipe, there was sudden drop in the fluid pressure, which implies a possible region of hydrate formation. This sudden drop in fluid pressure is indication that there isa presence of plugging which may eventually lead to blocking of the pipes (Davitashvili, 2021).

The initial pressure condition of the system was 68.94785 barg. However, the pressure of crude oil flows decreased slowly along the length to64.62061 bargat 9875.52 m length, as predicted by the PIPESIM software. This represents a difference of 4.432724 barg pressure change between inlet and the outlet points. Similarly, the predicted pressure at 9875.52 m length by the model is 64.91679 barg. This represents a difference of 4.03106 barg pressure change between inlet and the outlet points. The RMSE computed between the two predicted pressures along the various positions of pipe was 0.15923, and this implied that 15.92% error exist between the pressures predicted by the model and software. Despite the differences in the predicted pressures, there is indication that the lowpressureconditions can lead to formation of hydrate particles. This so because hydrates are more likely to form and grow when there is a lower pressure drop (Zuo et al., 2021). In addition, the fluid pressure predicted by the PIPESIM along the pipe is higher compared to the values predicted by the computed model.This disparity could be attributed to the coding of the model developed for the PIPESIM, which may have otherparameters or solution technique. This is justified by the work of Khamehchieta (2020), which also reported different levels of prediction using two modelswith different configurations.

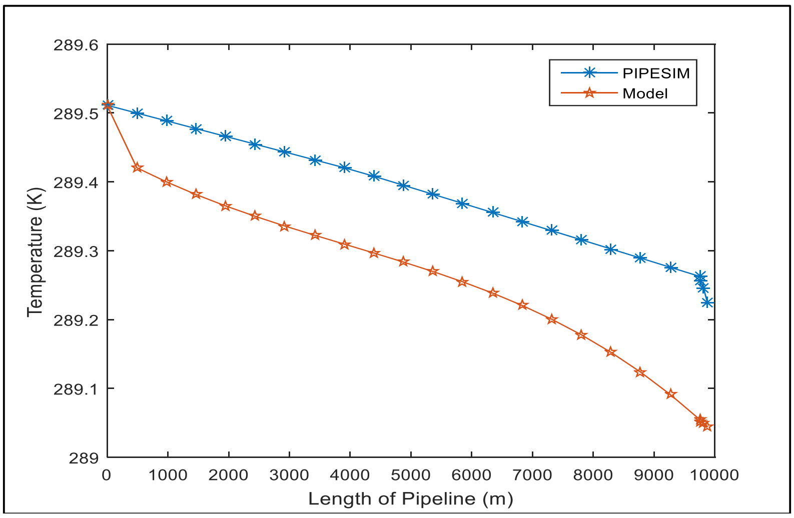

Figure 2: Comparison of temperature profile generated from PIPESIM and the model

Figure 2 shows the temperature distribution along the length of pipe, generated from the simulation with PIPESIM software and the manually computed model. The results presented in Table 1 for predicted temperature indicated that temperature varied along the length of the pipeline, but the range of variation is relatively small. The initial temperature condition of the system, which was 289.511 K, decreased gradually along the length of the pipeline. Thus, at the end of pipe (9875.52 m length), the fluid temperature predicted by the PIPESIM software was 289.225 K, while the by the developed model predicted 289.045 K. The RMSE computed between the two predicted temperatures along the various positions of pipe was 0.025995, which accounted for about 2.60% error. Therefore, from the Figure 2, it can be seen that fluid temperature predicted by the PIPESIM at any position in the pipe is higher than the temperatures predicted by the manually computed model. The differences between the predicted temperature values is expected because the code used in developing the PIPSIM for application to fluid mechanics analysis may not be the same as the model expressed in thecomputational fluid dynamic model (CFD) used in this study. However, on general perspective, it can be concluded that use of PIPESIM or the model to analyze temperature distribution along a pipe transporting crude oil in subsea will give a reliable prediction. This agreed with findings of previous studies on hydrate temperature prediction (Naseer & Brandstatter, 2011; Khamehchieta., 2020).

However, the decrease in fluid temperature experienced along the length of the pipe was due to heat transfer through convection from the outer surface, which caused the fluid to cool rapidly until it reaches the temperature of the surrounding seawater (Naseer & Brandstatter, 2011). This particular region presents favourable conditions for the formation and growth of hydrate particles, as the fluid temperature remains low (Jung et al., 2012). Naseer & Brandstatter (2011) also established that fluid temperature along a pipe transporting crude oil may considerably decreased, particularly near the pipe entrance and thereafter, converged gradually throughout along the length of pipeline.

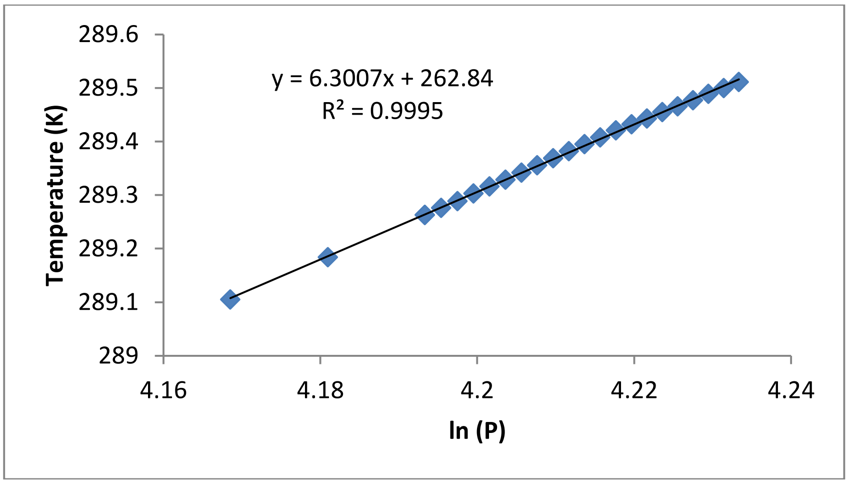

Figure 3: Correlation profile of gas pressure and temperature from PIPESIM model

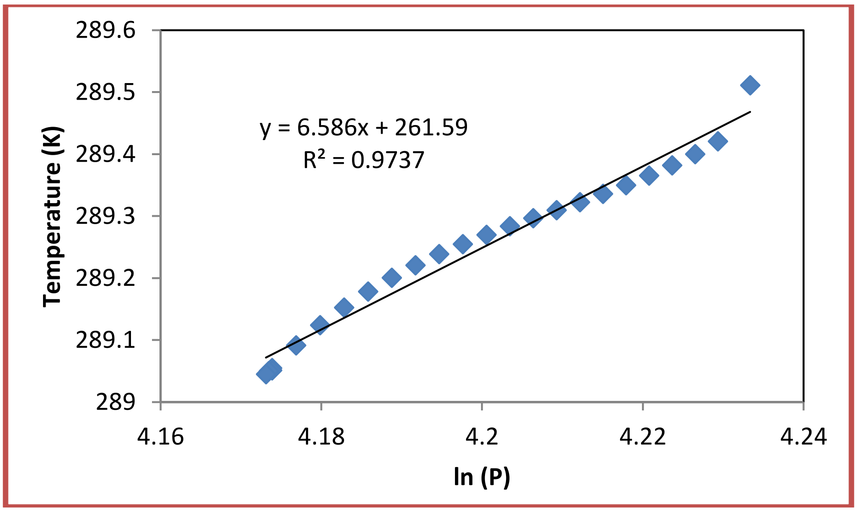

Figure 4: Correlation profile of gas pressure and temperature from the model

Figures 3 and 4 are the plots for correlation of pressure and temperature of fluid in the transmission pipe. The graph of Temperature (in Kelvin) against the natural logarithm of pressure (pressure in barg) generated from the PIPESIM and the model depicts a linear relationship. From the linear equations on the graph, it can be stated that there high correlation between the fluid temperature and the natural logarithm of pressure. Thus, the R^2 value for data generated from the PIPESIM and the model are 0.9995 and 0.9737, indicating that the correlation is stronger with value generated from the PIPESIM than values generated from the model.

However, the equations on the graphs implied that the fluid temperature can be predicted any known pressure along the flow line. Thus, for the PIPESIM, the predictive model can be expressed as $T = 6.3007\ln(P) + 262.84$ while that of the model can be expressed as $T = 6.586\ln(P) + 261.59$ In general, the gas temperature-pressure relation was well predicted by the model. This is in agreement with some other studies that correlated gas hydrate temperature with the natural logarithm of pressure (Naseer & Brandstatter, 2011; Davitashvili, 2021). Therefore, this model can be used to study the pressure and temperature of fluid correlation in the crude oil transmission pipe.

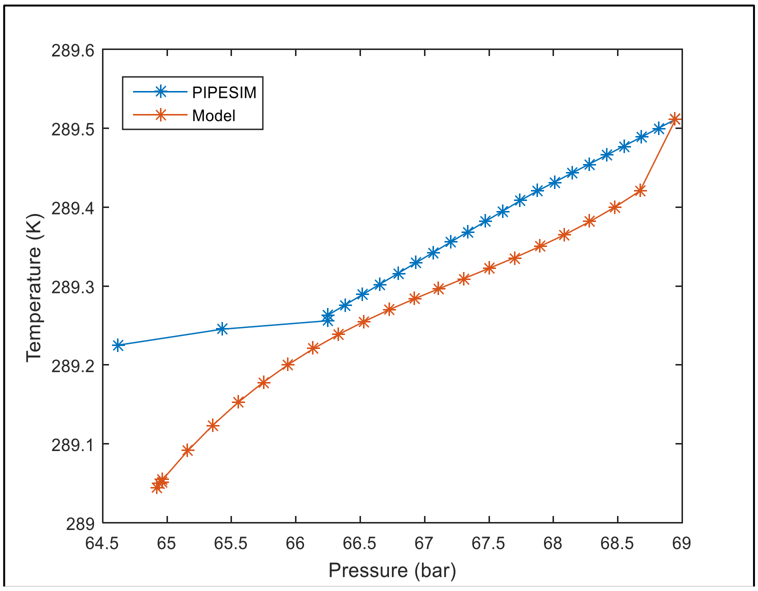

Figure 5: Correlation profile of gas pressure and temperature from the model

Figure 5 compares relationship between the fluid temperature and pressure along the transmission pipe, generated from the multiphase flow simulator (PIPESIM) and the model. The trends indicated in the figure shows that both techniques can be used to study the pressure and temperature at which hydrate can form in crude oil transmission pipelines. However, values generated by the PIPESIM seemed to be higher than those predicted by the model. Nevertheless, both techniques demonstrated that the formation of hydrates is more probable when the pressure drop is minimal. This observation was equally reported in previous studies, and it was stated that under these circumstances, the overall change in fluid pressure along the flow line is low, with low minimal changes in temperature willcreate favourable conditions for hydrates formation (Bergman et al., 2011; Cao et al., 2020; Davitashvili, 2021).

IV. Conclusion

This study compared the predicted pressure and temperature along crude oil transmission pipeline in subsea using PIPESIM software and fluid dynamic model. The findings revealed that the predicted pressure and temperature of fluid reduced along the pipeline. This indicates that there obstruction of flow in the pipeline, which is a sign of potential factors that can lead to hydrate formation. The finding also revealed that there is strong correlation between fluid temperature and the natural logarithm of the fluid pressure, but the pressure and temperature predicted by PIPESIM were higher than those predicted by the computational fluid dynamic model. Nevertheless, both models provided insights into the pressure and temperature conditions that can lead to the formation of hydrate in crude oil transmission pipelines. Furthermore, it is recommended that these models should be applied in real-time or experimental data to monitor crude oil flow line pressure and temperature in order to understand, predict and prevent hydrate formation region in subsea pipelines.

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