European Journal of Mechanical Engineering Research, 12(1),20-41, 2025

Print ISSN: 2055-6551(Print)

Online ISSN: 2055-656X(Online)

Website: https://www.eajournals.org/

Publication of the European Centre for Research Training and Development-UK

Flow Simulation and Experimental Validation of Crude Oil Hydrate Plugging in Pipelines using PIPESIM

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doi: https://doi.org/10.37745/ejmer.2014/vol12n12041 Published July 06, 2025

Citation: Tamzor L.A., Shadrack M.U., Briggs T.A. (2025) Flow Simulation and Experimental Validation of Crude Oil Hydrate Plugging in Pipelines using PIPESIM, *European Journal of Mechanical Engineering Research*, 12(1),20-41

Abstract: *This research attempts to improve upon the performance efficiency of crude oil pipelines in an oil field in south-south, Nigeria, comprising of flow lines 1, 2 and 3 of lengths (9874.6, 9265 and 12313) meters respectively. All with uniform ID of 0.254m, coated with 0.042m thick polyethylene. The well heads inlet pressures are (69.96, 72.18 and 76.85) bars. Flow Lines (FLs) have flow rates of (845.42, 650.0315 and 792.66) stb/d respectively. Pressure drop of (6.8 10.73 and 12.5) bar were recorded accordingly on these flow lines, with a cumulative output value of 2288.12 STB/d. PIPESIM software was utilized to model and simulate the following (0.2035m, 0.254, and 0.305m) IDs as sensitivity parameters for maximum (5000stb/d), normal (3000stb/d) and minimum (1000stb/d) flow rate cases. Out of which 0.2035m with 0.0635m insulation thickness was selected, for satisfying the optimal criteria, such as maximum flow rate of 5000 stb/d, and EVR max of 0.35 ≤ 1 specified by API RP 14E. Hydrate formed at 16.51^{o}C and 68.94 bar on Flow Lines. Performing sensitivity analysis on (FL) 1 enhanced pressure drop by 27.04% and flow rate improved by 70.9%. Pressure dropped by 29.17% with a flow rate improvement of 50.45% on (FL) 2, while on (FL) 3 it dropped by 19.92% and flowrate improved by 75.9%. The optimal operational temperature was 28.22^{o}C. While, the Simulation validation with experimental results shows, that inlet pressure of 68.94785 bars, slowly dropped along the length of the pipeline to 64.62061 bars at 9875.52m; giving a difference of 4.32724 bar. Also, the experimental loop inlet pressure of 69.94785 bars gradually dropped to 65.91679 bars at 9875.52 m length, giving a pressure difference of 4.03106bar. The hydrate formation temperature in the loop was 17.4931 ^{o}C while that of simulation was 16.5112^{o}C given 0.9819^{o}C difference. The RMSE computed between the simulated and experimental pressures were 0.0523873, meaning 5.2% errors exist and that computed between the two predicted temperatures was 0.025995, accounting for 2.60% error. The R^2 value for simulation and the experiment are 0.9995 and 0.9737, indicating a stronger correlation.*

Keywords: PIPESIM, Hydrate, crude oil, flow optimization, flow assurance. experimental validation, simulation

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INTRODUCTION

Crude oil is a liquid fossil fuel commonly made up of hydrocarbons, found both in underground reservoirs, and special geological structures characterized by their formation geologic depth, cracks, crevices, pores of sedimentary rocks and also in tar sands near the earth's surface (Elena *et al.* 2020). Nigeria has a substantial reserve of paraffinic crude oils known for their good quality (low sulphur, high API gravity), with moderate to high contents of paraffinic waxes. Crude oil products are the first primary non-renewable energy source so; the analyses, design, operations as well as its transportation play a key role for both private and public sectors. Pipeline is primarily used for crude oil transportation; it is estimated that the crude oil reserves in Nigeria are conservatively put at approximately 37.1 billion barrels at the beginning of 2023 with an average productivity of about 2.5 million barrels per day (Wang *et al.*, 2019). The reserve locked up in Nigeria soil is enough to last about 200 years, fueling our industries, homes and for export (Abarasi, 2014). It is explored through drilling or strip mining in the case of tar sand and oil shale, once extracted is conveyed to refineries via super tankers, train, trucks or pipelines for refining into usable fuels for instance gasoline, propane, kerosene and jet fuel as well as plastic products and paints (Patel *et al.* 2022). Crude oil is syrupy at reservoir conditions and it is difficult to move due to some unfavorable components such as asphaltenes, heavy metals and sulphur making it, complex to produce, transport as well as refine (Papa et al., 2022)**.** Without prior reduction in the stickiness of crude oil, transportation via pipeline is difficult; this is because it gulps huge energy in form of intense pump power to overcome the high pressure drop met in the pipeline due to high resistance to flow at reservoir conditions (Abarasi, 2014). Consequently, operating the pipelines at their optimal capacities will drastically reduce the huge tonnage of pipeline materials as well as reduce the environmental risks associated with crisscrossing the Nigerian landscape with inefficiently operated Crude oil pipelines.

Flow assurance

The mixed nature of flow erupts severe flow assurance challenges in pipelines and results to blockage of pipeline culminating into loss of revenue (Sun and Yang, 2015). These problems most likely maybe related to flow instabilities, solids formation that may block the flow path, erosion, corrosion and hydrate plugs that can even result in pipeline ruptures, all of which cause safety concerns (Hughes, 2008; Mein, 2012). Operations with long subsea flowlines need special attention with respect to flow assurance problems, especially with respect to hydrate formation (Ozi, *et al*. 2020). Roger (2000) reported that since 1998 crude oil production have declined at about 11% due to flow assurance issues particularly in the North Sea oil fields. Huang *et al.* (2015) said frictional pressure drops over pipe sections due to wax settlement in pipe segments reduces the hydraulic diameter of the fluid flow path inside the pipe which reduces flow production output.

Raheek *et al*. (2020) said flow assurance in the oil and gas production process, is a successful, nonstop, safe and economical flow of oil and gas stream from the oil wells to the end user or sales point, covering thermal investigation of pipelines, in keeping with the required temperature of the pipeline. Accurately calculating the pressure loss of oil pipelines is favorable to formulating the pumping schedules, which guarantees a better operation of the pipeline system and better economic efficiency, achieving the aims of cost saving, energy saving, and supporting the process of carbon neutrality (Zhou *et al.*2021; Zhou *et al.* 2019)

Flow optimization

Flow optimization focuses on enhancing the efficiency and effectiveness of fluid movement in systems such as pipelines, networks, or processes. This entails analyzing and adjusting parameters to reduce resistance, decrease energy consumption, and improve overall performance (Bekibayev *et al.* 2022). It is anticipated that optimization will notably lower the design and operational costs involved with oil field products networks. Within the context of gas or crude oil pipeline optimization, the primary objective is to maximize a specific economic metric while conforming to the performance equations that describe the system's physical behavior and any established constraints (Arya, 2022). Enhanced flow assurance improves downtime, prevents blockages and optimizes flow efficiency and extends flow life (Ozi, *et al*. 2020).

Hydrates

Gas hydrates are non-stoichiometric crystal compounds in the form of ice which are primarily formed by small light gas molecules for example Methane (CH_4) and ethane (C_2H_6) carbon dioxide (CO_2), as entrapped particles captured in voids created by liquid particles known as carrier molecules at extreme pressure as well as low temperature levels (Hassan *et al.* 2019). Anytime a system of natural gas and water molecules exists at specific conditions, mostly when the pressure is high and temperature is low then, hydrate might likely form. However, at milder environmental conditions hydrate can still form, mostly when the concentrations of the guest molecules, for instance carbon-dioxide, methane are high in the surrounding or specific chemical interactions are involved. The process that leads to hydrate formation in pipelines comprises water vapor condensation, buildup of water at lowered sections of the pipeline, nucleation and growth of hydrate particles ultimately blocking the pipeline. Gas hydrates have enticed massive interest in scientific and practical studies because of the wide variety of potential applications. Hydrate is a key source of energy in the 21st century (Zuo et al., 2021). Hydrate can hoard gas almost about 170-times its volume Gudmundsson et al. (1994) therefore, can be used in gas storage and transportation and carbon sequestration. Hydrate is utilized for desalination since dissolved salt is left out as hydrate is formed because free water alone is involved in hydrate Xu and Li, (2014). By utilizing selective partitioning of different gases in the hydrate and gas phases, hydrate can be used for separation of gas Eslamimanesh *et al*. (2012b). Delahaye *et al.* (2008) reported that hydrate slurries are used as an effective cooling fluid in refrigeration applications. Nevertheless, hydrate

failed because it causes blockage which has an awful safety consequence and economic losses Sloan and Koh (2007). Furthermore, it can plug pipelines, risers, subsea well- heads and cause a well-control risk (Khamehchieta, 2020).These blockage issues lead to reduced production output, increased energy input, and increased pump power consumption. Hydrate plugs in pipelines poses threat to personnel and equipment (Sloan, 2008). Hydrate plugs can also cause rupture (Ninalowo and Tohidi (2024) and cause production downtime (Peters et al. 2022). Hydrate blockage on pipelines causes infrastructural damage to the facility (Arya, 2022). Blockage resulting from hydrate formation causes increased operating expenses Jai *et al.* (2021). Hydrate plugs in a deep-water gas pipeline in the Gulf of Mexico caused 5 days total shot down of facility and caused a production loss of about $ 20 million, remediation and repair cost of $ 2 million as well as an environmental management loss of $ 500,000 (Ke, *et al.* 2022). Hydrate remediation and emergency intervention as well as mechanical evacuation gulps millions of dollars per year (Onyegiri *et al.* 2020). Millions of Dollars could be lost by operators due to short term interruption by hydrate. Even a short-term interruption in production can cost the operator millions of dollars, sometimes hydrate obstructions in crude oil and gas transportation lines could result from chemical injection system failure, unplanned cessations at the host platforms, or insufficient Suppressant treatment at well start up (Ninalowo and Tohidi 2024). The best way of tackling hydrate-related flow assurance problems is prevention, but some operational conditions like offshore operations usually guarantees hydrates formation in pipelines, as shown in figure 1. This is attributed to the twin circumstances of high pressure and low temperature frequently encountered in offshore (Hong *et al.* 2006).

Properties and structure of Gas Hydrates

Studies on Hydrate require expanse knowledge about hydrate elements and configuration. When hydrate forms, H2O particles connects with hydrogen to produce polyhedral enclosures, containing the hydrate main cellular structure (Aregbe, 2014). Gas particles are stuck in the cavities with H_2O by van-der Waals forces, forming Gas clathrates Natural gas typically made of Methane gas when burnt in air produces water, CO2 and energy, shown in Equation (1)

$$CH_4 + O_2 \rightarrow CO_2 + H_2O + Energy \uparrow \quad (1)$$

This process generates energy that can be used for diverse purposes; $CO2$ is produced as more energy is given out. Figure 1 is the gas hydrate structure, displaying CH4 gas as the middle accommodator in green, while water molecule is in (pink) (Aregbe, 2014).

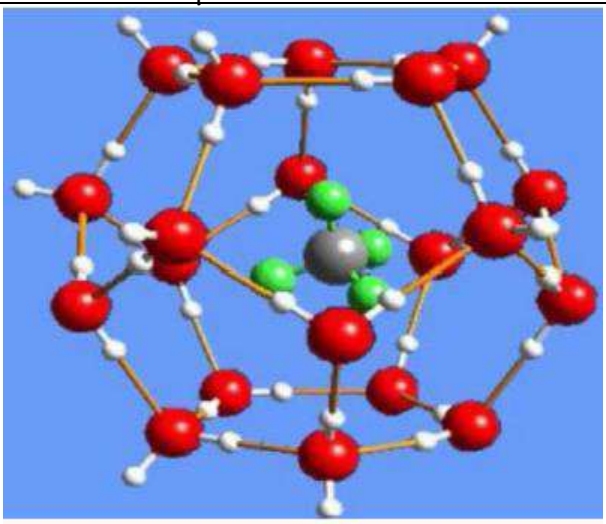

Figure 1: Cage-like gas hydrate structure (Aregbe, 2014).

Problems and economic losses caused by hydrate formation in pipelines

Hydrate formation in oil and gas pipelines is an unwanted situation which challenges the flow assurance plans as well as posing threat to the personnel and equipment (Sloan 2008). Hydrate plugs clusters to block tubing, flow lines and facilities, apart from blockage of pipeline another challenge hydrate poses is the movement of hydrate plugs in the pipeline at high velocity which can cause rupture in the pipeline (Ninalowo and Tohidi 2024). Hydrate formation in oil pipeline causes production downtime (Udayakantha et al 2022). The hydrate just released from the pipe wall along the length may migrate downstream and deposit at sagging sections of the pipeline to cause the blockage (Song et al. 2019).Hydrate blockage on pipelines causes infrastructural damage to the facility (Arya, 2022). Blockage resulting from hydrate formation causes increased operating expenses (Jai, et al 2021). Hydrate plugs in a deepwater gas pipeline in the Gulf of Mexico caused 5 days total shot down of facility and caused a production loss of about $ 20 million, remediation and repair cost of $ 2 million as well as an environmental management lost of $ 500,000 (Ke, et al., 2022). Hydrate remediation and emergency intervention as well as mechanical evacuation gulps millions of dollars per year (Onyegiri*et al.* 2020). Sometimes hydrate obstructions in crude oil and gas transportation lines could result from the failure of the chemical injection system, unplanned shutdowns at the host platforms, or insufficient inhibitor treatment during well start up (Ninalowo and Tohidi 2024). The cost of battling hydrates, working blockages, putting in place pipeline impairment as well as handling safety and environmental hazards can majorly impact on profitability of operators of the pipelines mostly in intricate and inaccessible environments, even a short-term interruption in production can cost the operator millions of dollars (Chen, et al. 2021).

Significance

The best way of tackling hydrate-related flow assurance problems is prevention (Ninalowo and Tohidi 2024). But some operational conditions like offshore operations usually guarantees hydrates formation in pipelines (Chen *et al*. 2021). This is attributed to the twin conditions of low temperature and high pressure frequently encountered offshore (Hong *et al*., 2006). One of the most practical ways of initiating gas hydrates dissociation is either depressurization or thermal dissociation (Okoli *et al*., 2024). Depressurization involves opening of valves to release pipeline pressure, while thermal dissociation involves application of heat. These are usually done simply to move the prevalent conditions outside the hydrates stability region through either decrease in pressure or increase in temperature. Although depressurization is usually preferred due to its associated low-cost, but it presents considerable hydrates reformation risks due to possibility of Joule-Thompson cooling (Eyankware *et al*., 2021). This unwanted cooling ends up worsening the hydrates problem and can even lead to formation of ice. The above demerits of the depressurization informed the choice of hydrates dissociation by thermal dissociation, as it is believed that sustained supply of heat would significantly decrease the chances of dissociated hydrates reforming. Other means are the use of optimization algorithms, machine learning algorithms and software (Arya, 2022).

Particle Swarm Algorithm (PSA) has least calculation time and has a higher converging time, it has more advantages in solution time and optimization efficiency, high computation efficiency as well as good in handling discrete variables over classical deterministic optimization Algorithms (Liu et al. 2020). Viscometry technique has inherent shortcomings and should not be used solely for flow assurance issue characterization except with other methods (Mahmoud et al. 2021) GPR model succeeds by its inherent flexibility in capturing complex nonlinear relationships and dependencies within a dataset (Aleem *et al.* 2024). Computational and numerical methods are good for their sustainable formation forecast of the hydrate scheme (Abbasi et al. 2022).Whereas, the use of software for simulation and artificial intelligence approaches are used due to their propensity to handle ambiguity and uncertain data sets effectively (Yin, et al., 2016).The use of software for the optimization of hydrate stems from the user-friendly environment which includes GUIs that makes it easier to apply as against manual coding that is experience with algorithms (Wang, et al. 2019). Software has built in thermodynamic models, hydrate phase equilibrium data bases contrary to external data integration and validation, which is time-consuming and error-prone as with algorithms (Sayani *et al.* 2021).

METHODOLOGY

Hydrate formation in crude oil pipeline is a function of many factors however, the pressure and temperature of the crude oil transmision pipe was simulated to study the condition for which hydrate can form. First, the simulation was performed using a developed software called PIPESIM, which is designed for simulation of multiphase flow. Secondly, experimental data was used for the study of hydrate formation in transmission pipes to predict the pressure and temperature of the

crude oil along the pipes. The predicted pressures and temperatures were compared to ascertain the level of error between the two modelling approaches.

Hydrate formation Simulation

However, simulations have been used to study the effects of these variables on the formation of hydrate in pipes. According to Marfo et al. (2019), the basic parameters that are simultaneously simulated for a non-steady state flow and non-isothermal systems include the fluid velocity, pressure, temperature, or density. The simulation set up is as follows: This is a crude oil (gathering systems) transportation pipe line 1, 2 and 3, in south-south, Nigeria. The subsea flow lines 1, 2 and 3 are 9874.6m length, 9265m length and 12313m length. All of which have internal diameter of 0.254m and all coated with 0.042m thick polyethylene material.

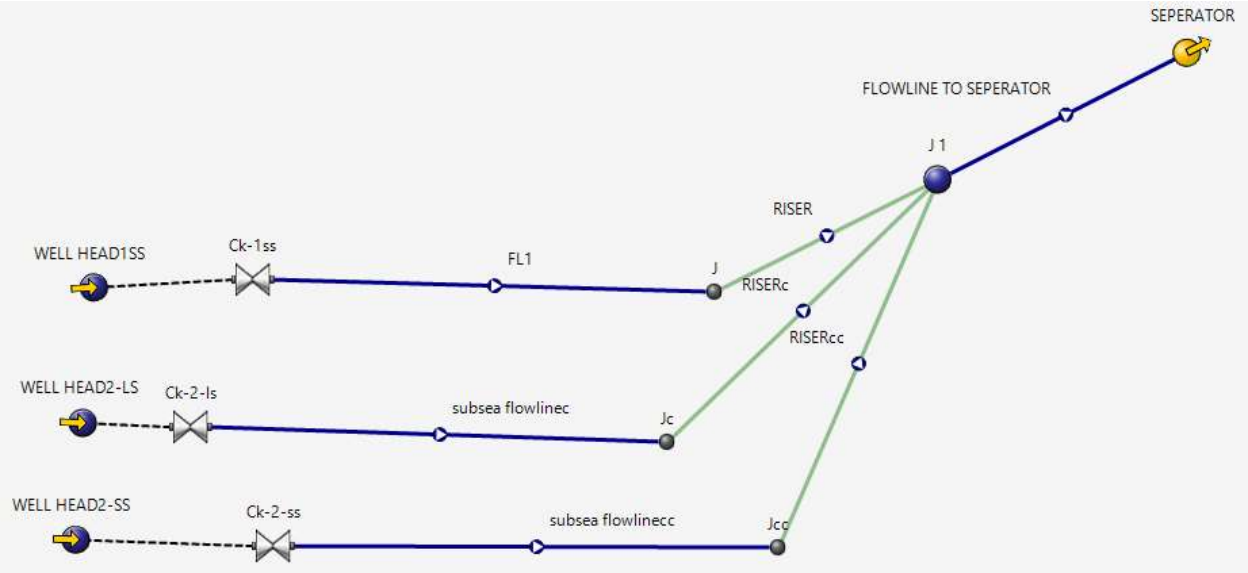

Figure 2: Physical model of the flowlines using PIPESIM-2017

Table 1: Fluid property and boundary condition table

Well Head				
Boundary condition:				
Fluid inlet pressure at well head			76.85 bar	
Fluid temperature at well head			29.86^0C	
design production rate			3000 STB/d	
Maximum rate			5000 STB/d	
Maximum turndown	when production drops		1000 STB/d	
minimum arrival pressure at processing platform			41.37bar	
Allowable pressure drop			4.99bar	
minimum arrival temperature at processing platform			21.1 ^{o}C	
PURE HYDROCARBON COMPONENTS:				
Component	Moles			
methane	73			
Ethane	5.2			
Propane	2.5			
isobutane	1			
Butane	1			
Isopentane	1			
Pentane	0.5			
Hexane	0.5			
Carbon dioxide	2.1			
Petroleum Fraction:				
Name	Boiling point (^{o}C)	Molecular weight	Specific Gravity	Moles
C7+	101.111	115	0.8285	8.2
Aqueous Component				
Component	Volume ratio (%bbl/bbl)			
Water	5			

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RESULTS AND DISCUSSIONS

Phase envelop development and determination of hydrate formation temperature (HFT) and pressure values.

The fluid manager in PIPESIM 2017, hydrocarbon components was flashed at 29 ^{o}C and the phase envelop for the fluid composition was generated as shown in figure 3. The hydrate formation temperature of 16.51^{o}C and pressure of 68.94 bars was. This result is similar to the result obtained in the studies conducted by (Davitashvili, 2021) that correlated gas hydrate formation temperature with the hydrate formation pressure. It also corroborate the work done by (Onyegiri, et al., 2020)

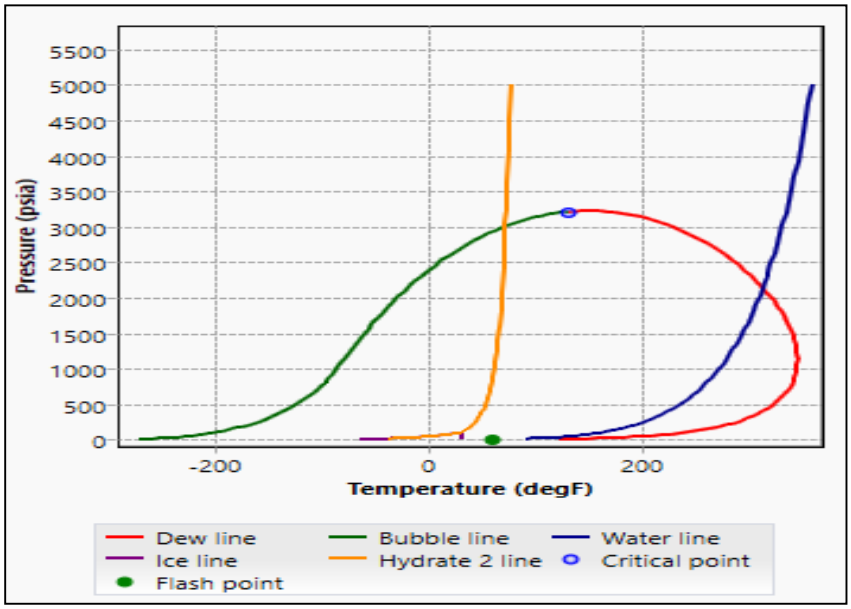

Figure 3. Phase envelop generated from compositional fluid in PIPESIM

Pipe size selection and Prediction that it does not cause Erosional velocity

According to the API RP 14E criteria (Schlumberger, 2024) that the maximum erosional velocity ratio(V_{emx}) should be ≤ 1, thus equations (2) and (3) for the determination of the erosional velocity value.

$$V_{emx} = 1.22 \times \frac{C}{\sqrt{\rho_m}} \quad (2)$$

$$\rho_{\boldsymbol{m}} = \frac{12409 \times S_{gl} \times P + 2.7 \times S_{gg} \times P}{198.7 \times P + R \times T \times Z} \quad (3)$$

where,

V_{emx} = Maximum Erosional Velocity (fract,); C =100; ρ_m = Mixture density (kg/m^3) provided in PIPESIM output file; P = Operating Pressure (bar); S_{gl} = Liquid specific gravity at standard condition (-); S_{gg} = Gas Specific Gravity (-); R = Gas Universal Constant; T= Operating temperature (^{o}C); Z= Gas Compressibility Factor (-)

The following sensitivity parameters 0.2035m, 0.254 and 0.305m were utilized in performing the simulation processes of pipeline and riser sizing against the respective production cases of maximum, normal and minimum flow rates. This task was undertaken to select the appropriate pipe size that will deliver at a maximum flow rate of 5000 STB/d, required outlet pressure above hydrate formation pressure and maximum erosional velocity ratio of 0.35 met the criteria of (EVR max $\leq$ 1) specified by API RP 14E. PIPESIM, simulation results showed that 0.2035m, 0.254m and 0.305m line sizes met the required criteria, as presented in figure 4 and Table 2. However, flow line 0.2035m was selected, because of other considerations, such as the cost implications and other economic conditions. This result corroborates with the erosional velocity values obtained in the work done by Onyegiri, et al., (2020). The graph of figure 4 shows that pressure drop increases as flow rate gets bigger. The observed trend in the pipeline selection is similar to what is presented in the work done by Ozi, et al., (2020)

Table 2: Maximum erosional velocity ratio for the respective flow rates and all the flow line sizes

Flow rate (STB/d)	0.203(m)- ID EVR max	0.254(m) -ID EVR max	0.305(m)- ID EVR max
1000	0.07	0.04	0.03
3000	0.21	0.13	0.09
5000	0.35	0.22	0.15

Determination of suitable insulation thickness to prevent hydrate formation on the selected flow line

For the flow line to be out of hydrate formation region, the graph must fall within the negative region of hydrate sub-cooling region. Thus, a suitable insulation thickness was proposed for the flowlines by simulating the appropriate thickness that will keep the fluids flow above the HFT during the service life of the wells using the heat transfer coefficient, U value of U = 1.136W/.m^{2}K) The proposed sensitivity thicknesses were 0.0127m, 0.0254m, 0.0381m, and 0.0635m. The results

of the simulation of these proposed thicknesses in PIPESIM are presented as figures 5a and 5b, 5c, and 5d respectively.

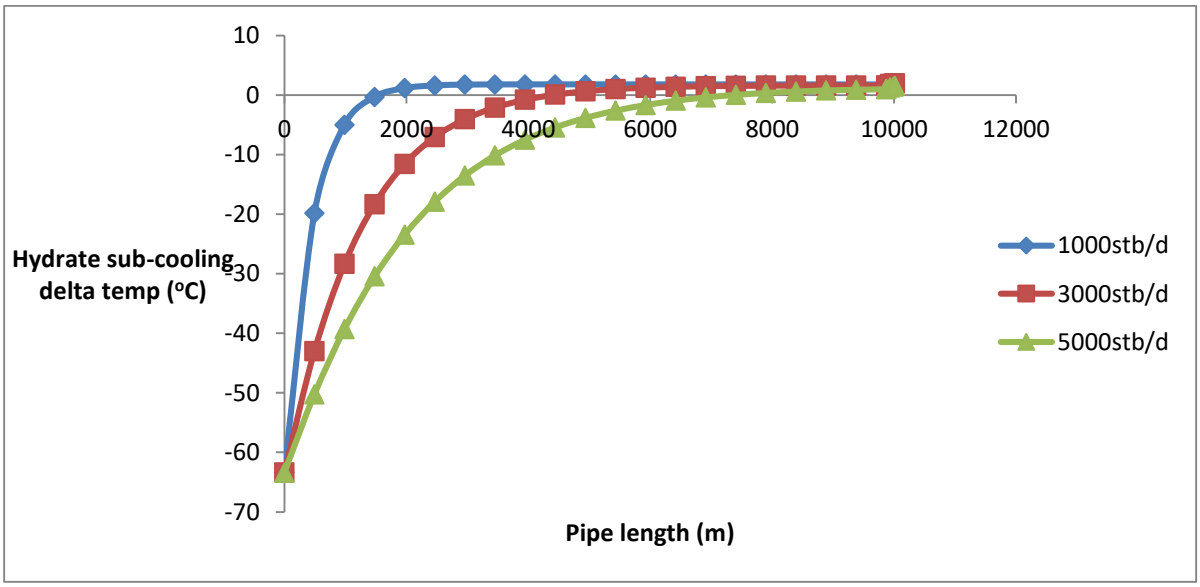

Figure 4: Flow line 0.2035m with insulation thickness of 0.0127m and thermal conductivity K= 0.3 (W/m. K)
All flow rates are still within hydrate region

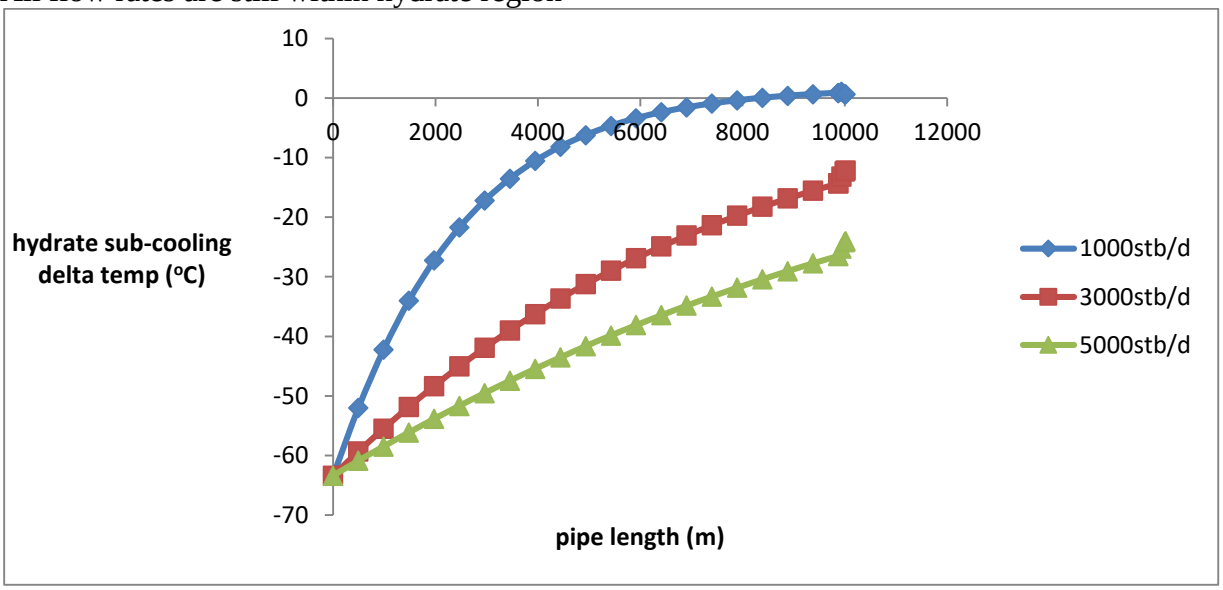

Figure 5: Flow line 0.2035m with insulation thickness of 0.0254m (polyethylene) material and thermal conductivity K= 0.3 (W/m. K)

Flow rates of 1000stb/d was still in the hydrate region, whereas 3000 stb/d and 5000stb/d were out of hydrate region

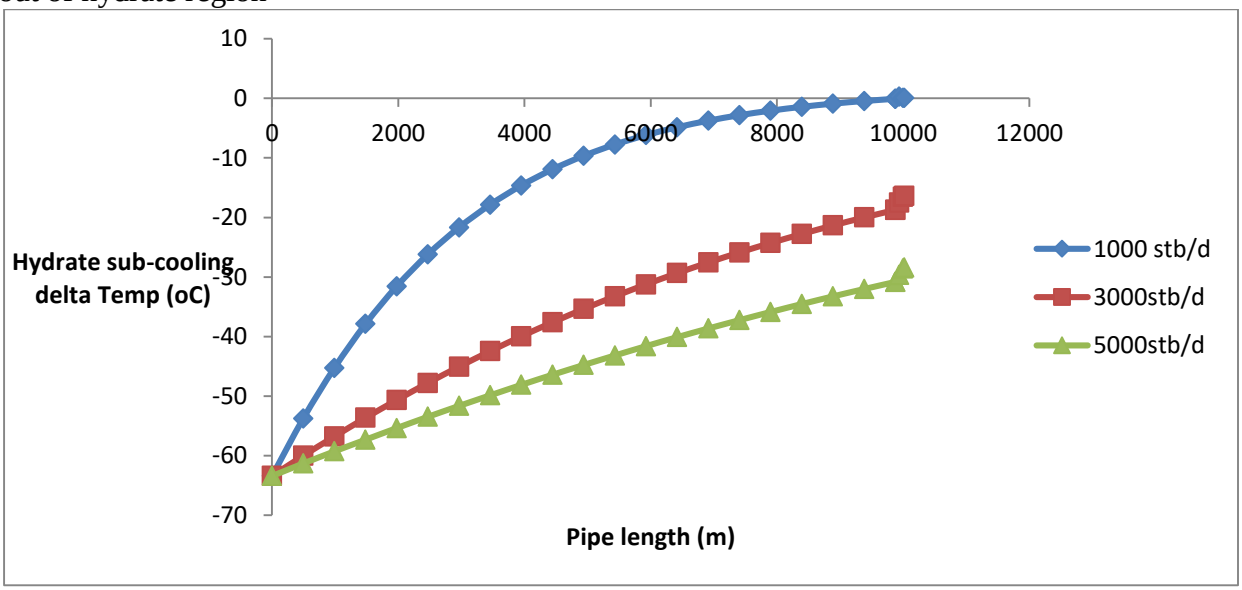

Figure 6: Flow line 0.2035m with insulation thickness of 0.0381m (polyethylene) material and thermal conductivity K= 0.3 (W/m. K)

Flow rates of 1000stb/d was still in the hydrate region, whereas 3000 stb/d and 5000stb/d were out of hydrate region

The result showed that, 0.0635m insulation thickness, and thermal conductivity value K= 0.3 (W/m. K) and U value of U = 1.136W/.m^{2}K) eventually, brought all the flow rates out of hydrate region as shown in figure 5b, this corroborates with the insulation thickness and thermal conductivity as used in the work by Onyegiri, et al., (2020)

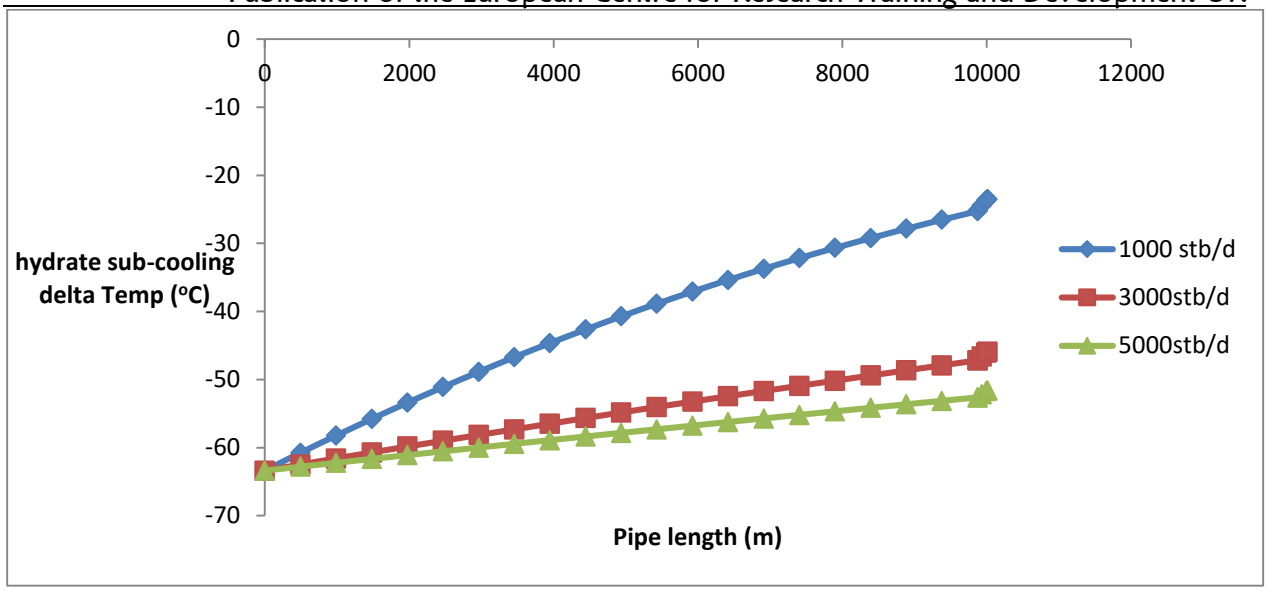

Figure 7: Flow line 0.2035m with insulation thickness of 0.0635m (polyethylene) material and thermal conductivity K= 0.3 (W/m. K). All flow rates were out of hydrate region

Table 3: Experimental hydrate formation temperature values and simulated temperature values

Pipe length (m)	Simulated temp (oC)	experiment temp (oC)
0	16.5112	17.4931
488.67	16.4999	17.4549
975.36	16.4887	17.4188
1463.04	16.4773	17.3845
1950.72	16.466	17.3522
2438.4	16.4547	17.3217
2926.08	16.4433	17.2932
3413.76	16.4319	17.2665
3901.44	16.4205	17.2418
4389.12	16.4081	17.2189
4876.8	16.395	17.198
5364.48	16.3819	17.179
5852.16	16.3687	17.1618
6339.84	16.3555	17.1466

6827.52	16.3423	17.1333
7315.2	16.3291	17.1218
7802.88	16.3158	17.1123
8290.56	16.3026	17.1047
8778.24	16.2893	17.099
9265.92	16.276	17.0952
9753.6	16.2626	17.0932
9753.6	16.256	17.0932
9814.56	16.2454	17.0931
9875.52	16.2252	17.0931

The results obtained from the experiment and PIPESIM simulations were compared using the root mean-square error (RMSE) stated in equation (4).

$$RMSE = \sqrt{\sum_{i=1}^{n} \frac{(PIPESIM_{simu} - Exp_{simu})^2}{n}} \quad (4)$$

where
$PIPESIM_{simu}$ is the predicted pressure or temperature using PIPESIM simulation
Exp_{simu} is the predicted pressure or temperature from experiment
n is the number of positions along the pipe

To obtain the percentage error or deviation between the two predicted values, the calculated RMSE value was multiplied by 100%.

Table 4. Experimental data used for PIPESIM simulation

Input experimental parameter	Value
Flow loop inlet pressure, P	1,014.68Psi (69.94785bar)
Flow loop temperature, T	290.6431K (17.4931ºC)
Design production rate	5000 STB/d
Pipe inner diameter	0.2035 m
Wall thickness	0.0081 m
Horizontal distance, L	12000 m
Speed of sound propagation in gas, C	300m/s
Fluid density	828.5 kg/m^3
Fluid velocity	0.228 m/s
Specific heat capacity	2.1 kJ/ kg. K

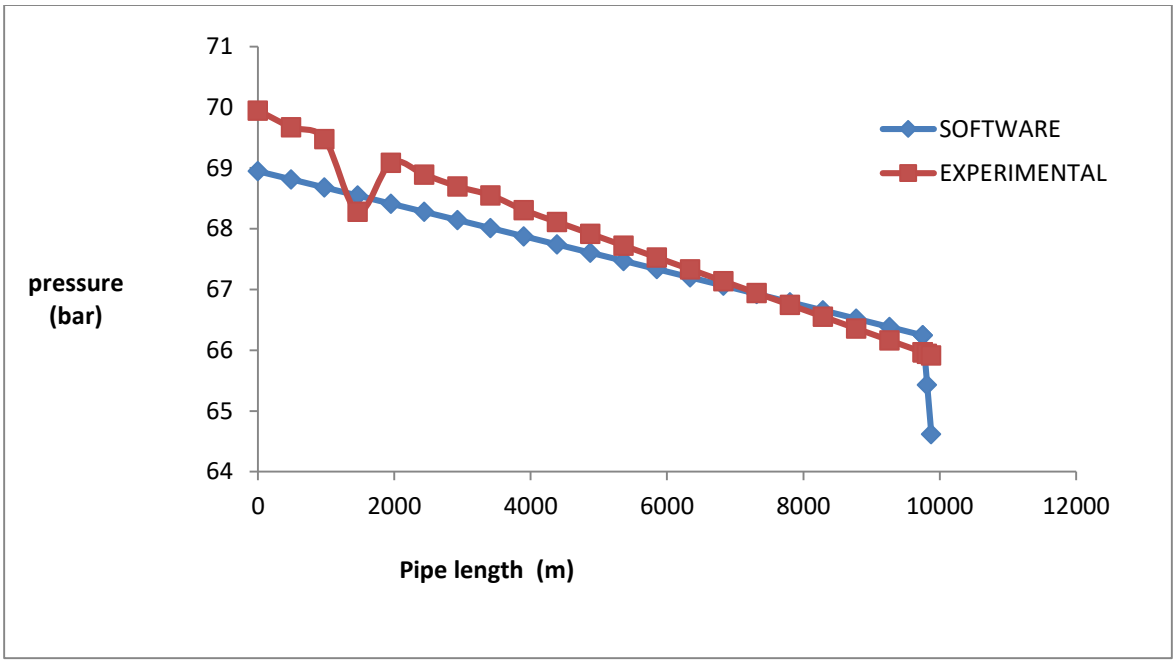

Figure 8: validation of simulation with experimental data (hydrate formation pressure)

From Figure 8 the pressure change is an indication of pressure drop, which occurred due to friction on the walls of the pipe and obstructions from developing impurities such as scales and particles with potentials to form hydrates. From figure 8, the simulation results 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 abrupt plunge in fluid pressure indicates that there is a likelihood of plugging which may finally result to blocking of the pipes (Arya, 2022) The original inlet pressure of the system was 68.95 bars however, the pressure of the flow gradually dropped along the length to 64.62 bar at 9875.52 m length, as predicted by the software. This means a 4.322bar pressure change between inlet and the outlet points. Also, the inlet pressure of the experimental system was at 69.95 bars and it dropped to 65.91bar at 9875.52 m. This means a difference of 4.031 bar pressure change between inlet and the outlet points. The RMSE computed between the two predicted pressures along the various positions on the pipe line was 0.0523873 and this implied that 5.2% errors exist between the pressures predicted from the experimental data and simulation. Regardless of the differences in the predicted pressures, there is sign that the low-pressure conditions can lead to formation of hydrate particles. This is so because hydrates are more likely to form and grow when there is a lower pressure drop (Onyegiri et al,. 2020). Furthermore, the fluid pressure predicted using the experimental data along the pipe line is higher compared to the values predicted from simulation. This disparity could be attributed to the impurities in flow path,

friction, calibration drift and also insulation imperfection in the experimental flow line. This corroborates the work of (Davitashvili, 2021). Khamehchieta. (2020), which also reported different levels of prediction using experiment and models with different configurations as shown in the figure 8

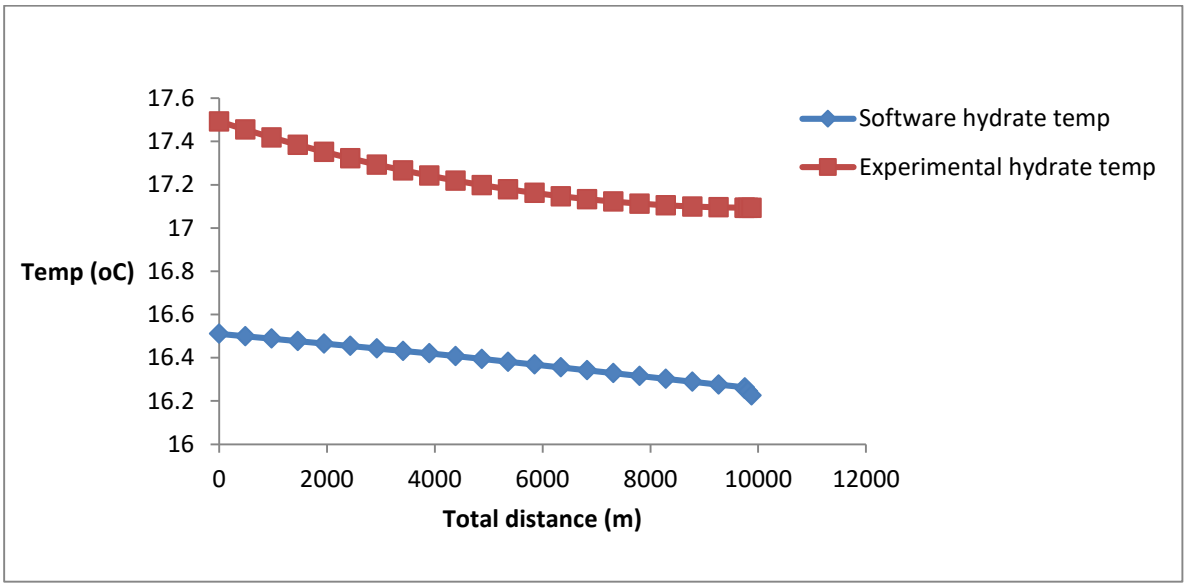

Figure 9: validation of simulation with experimental data (hydrate formation temperature)

Figure 9, shows the temperature profile along the length of pipe, generated from the simulation with PIPESIM software and the experiment. The results presented in Table 3 for predicted temperature indicates that temperature varied along the length of the pipeline, although, the variation is relatively small, it can be seen that fluid temperature predicted from experiment at any position in the pipe is higher than the temperatures predicted by simulation.

The initial temperature condition of the simulation, which was 16.5112 ^{o}C, reduced progressively along the length of the pipeline. as a result, at the end of pipe 9875.52 m length, the fluid temperature predicted by the simulation was 16.22 ^{o}C , while the temperature from the experimental was 17.49 ^{o}C, initially and dropped to 17.09^{o}C along the length of the pipe line at 9875.52m. The RMSE computed between the two predicted temperatures along the various positions of the pipe was 0.02575, which accounted for about 2.60% error. The differences between the predicted temperatures values are expected because the code used in developing the PIPESIM for application to fluid mechanics analysis may not be the same as the experimental conditions due to the fact that, there may have been impurities in flow path, friction, calibration drift and also insulation imperfection in the experimental flow line which induces delays and frictions. However, on general perspective, it can be concluded that use of simulation or

experiment 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).

Nevertheless, the reduction experienced in temperature along the length of the pipe was due to convective heat transfer from the outer surface, which caused the fluid to quickly cool until it reaches the temperature of the surrounding seawater (Naseer & Brandstatter, 2011). This very domain presents conducive conditions for the formation and growth of hydrate particles, as the fluid temperature remains low (Jung et al., 2012). Naseer & Brandstatter (2011) also predicted that fluid temperature along a pipe transporting crude oil may significantly decrease, mainly near the pipe entrance and afterward, congregate slowly throughout along the length of pipeline.

Figures 10 and Figure 11 are the plots for correlation of pressure and temperature of fluid in the transmission pipe. The graph of Temperature (K) against the natural logarithm of pressure (bar) generated from the simulation and experiment illustrates a linear relationship. From the linear equations on the graph, it can be stated that there is high correlation between the fluid temperature and the natural logarithm of pressure. Thus, the R^2 value for data generated from the simulation and the experiment are 0.9995 and 0.9737, indicating that the correlation is stronger with the values generated from the simulation than values generated from the experimental data.
Generally, the fluid temperature-pressure relation was well predicted by the model. This agrees with the studies of Naseer & Brandstatter, (2011) and Davitashvili, (2021) that correlated gas hydrate temperature with the natural logarithm of pressure.

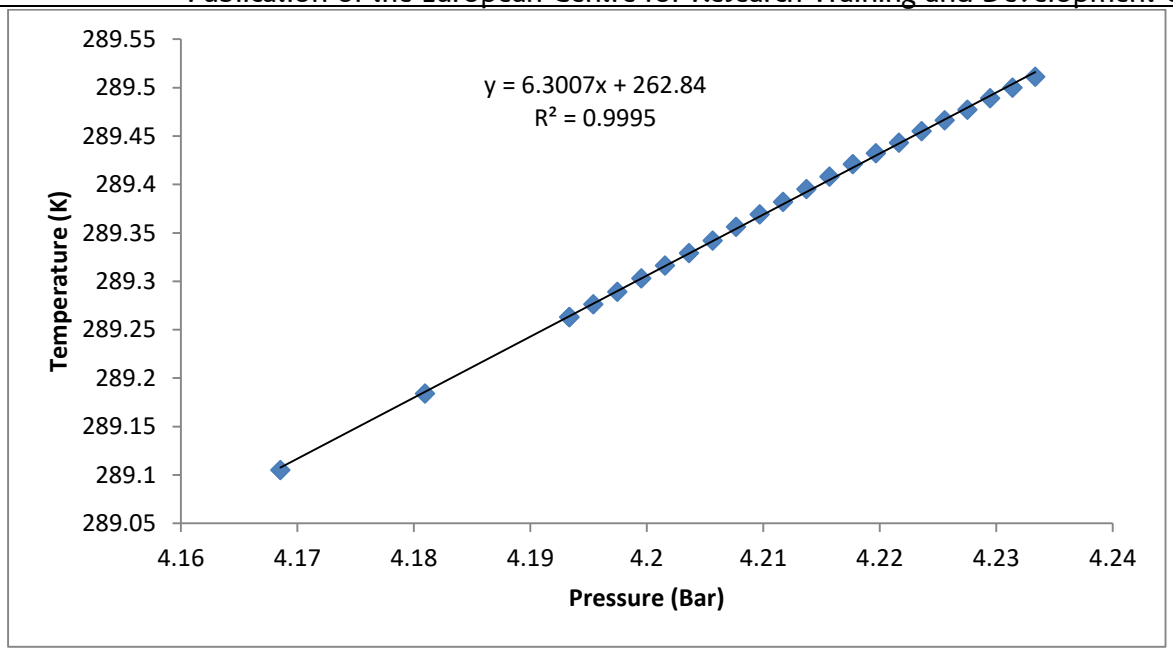

Figure 10: Correlation profile of fluid pressure and temperature from simulation

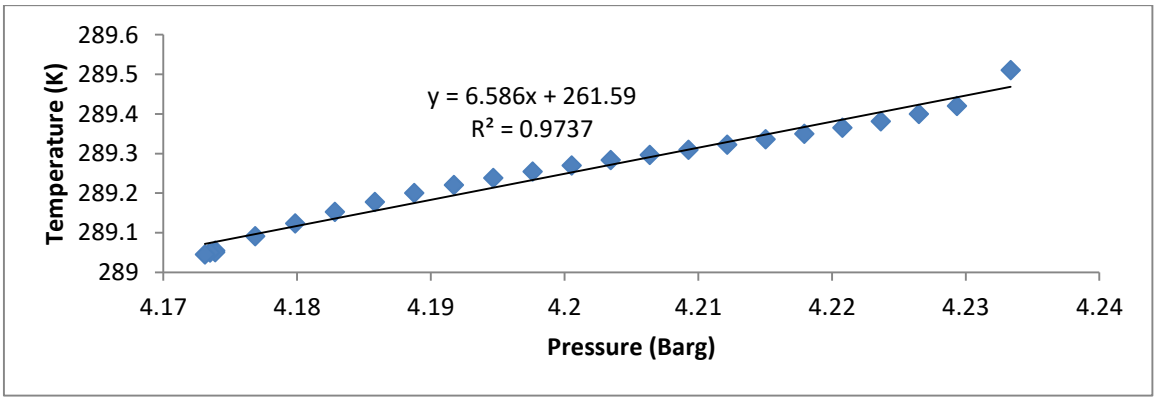

Figure 11: Correlation profile of pressure and temperature from the experiment

CONCLUSION

This study simulated pressure and temperature along crude oil transmission pipeline in subsea using PIPESIM software and experimental data. The findings revealed that pressure and temperature of fluid dropped as the flow continues along the length of the pipeline. This indicates that there is obstruction of flow in the pipeline, which is a sign of potential factors that could lead

to hydrate formation. At base condition the pressure drop on the three flow lines were recorded to be 6.8 bar, 4.8 bar and 5.5bar and flow rates of 845.421 stb/d, 650.0315 stb/d and 792.66stb/d respectively. After the simulation using the sensitivity parameters and analysis of the system, in PIPESIM the pressure drop on the pipelines were reduced to 4.93bar, 3.98 bar and 4.35 bar and flow rates increased correspondingly to 1445.321stb/d, 1312.56 stb/d and 1394.64 stb/d on the flow lines. This is a remarkable improvement on the flow lines accomplishing the minimum separator pressure above the HFT at 22.08 ^{o}C needed to deliver 5000 stb/d, summarily, this account for 39.12% pressure drop savings with 44% improvement in output flow rate of the entire system. Furthermore, the study compared the predicted pressure and temperature along crude oil transmission pipeline in subsea using PIPESIM software and experimental results. It was established that the inlet pressure of 68.94785 bars, slowly dropped along the length to 64.62061 bars at 9875.52m; giving a difference of 4.32724 bar. While, the experimental loop inlet pressure of 69.94785 bars gradually dropped to 65.91679 bars at 9875.52 m length, giving 4.03106 bar pressure difference. The hydrate formation temperature of the loop was 17.4931 ^{o}C while that of simulation was 16.5112^{o}C given 0.9819^{o}C difference. The RMSE computed between the simulated and experimental pressures were 0.0523873, meaning 5.2% errors exist. The RMSE computed between the two predicted temperatures was 0.025995, accounting for 2.60% error. The R^2 value for simulation and the experiment are 0.9995 and 0.9737, indicating a stronger correlation.

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