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Modeling and Simulation of the Temperature Profile along Offshore Pipeline of an Oil and Gas Flow: Effect of Insulation materials

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Abstract:- In offshore area, flowing parameters such as temperature and pressure must be controlled in order to guarantee a safety and economical transportation of fluid along pipeline. This can be achieved by using numerical simulations. In this paper, a mathematical model for predicting temperature and pressure profile along offshore pipeline during oil and gas transportation is presented. The model obtained from general formulation of pressure and temperature equations during two-phase flow is discretized and solved iteratively using a Matlab code. The numerical simulations results, shows a good agreement with a relative error of 1.16% on a field data obtained from literature. Further, effect of three insulation layers consisting of calcium silicate, black aerogel and polyurethane foam along with different insulation material thickness ranges between 0.0254 m and 0.0635 m, as well as different oil flowrates, on the temperature profile are analyzed. Required insulation material, insulation thickness and minimum inlet temperature for maintaining a minimum flow temperature of 313.15°k at any point in the offshore pipeline are determined. Results shows that an inlet temperature of 343.15°k with a thickness of 0.0635 m of black aerogel satisfied the requirement. It is shown that, the proposed model has predicted the temperature distribution very well.

Keywords:- *Temperature Profile, Offshore Pipeline, Numerical Simulation, Insulation Material, Two Phase Flow.*

I. INTRODUCTION

During transportation of oil and gas inside offshore pipeline, the fluid inside pipeline losses heat because of the temperature difference between the cooler surrounding and the warmer fluids. Consequently, if the fluids temperature drop below the wax appearance temperature or the hydrate appearance temperature, wax and hydrates deposition will occur which may lead to a reduction of the effective flow area of pipe and if serious, blockage may occur [1]. Pipeline blockage significantly influence the economical operation and financial benefit of the oil and gas industry. With today's low oil price and high rig rate, the industry is struggling with cost reduction [2]. Therefore, it is very important to carefully manage the thermal design of offshore pipeline in order to control the heat loss and thus, to prevent additional loss resulting from maintenance operations related to the flow assurance issues. Temperature distribution is therefore of great importance in any design process of oil and gas transportation.

In the open literature, many authors have been interested in the topic of temperature modeling and simulation inside offshore pipelines and wellbores for single and multiphase flow as it is shown in [1, 2, 4-11] among others. From these studies, it comes out that:

- temperature and pressure are dependent;
- the temperature profile model obtained for multiphase flow is different from that of single-phase flow because of complexity of the dynamical behavior of the multiphase;
- fluids properties are determined using black oil or component model as presented in [5, 12, 15];
- pressure profile is modeled using homogeneous or separated phase model [11-145].
- single-phase temperature distribution can e determined using analytical or numerical solution.

Temperature profile investigation in offshore pipeline is mostly to find out the thermal management strategy appropriate to limit some of the flow assurance issues such as wax and hydrate formation and deposition. Insulation materials revealed to be one the various thermal strategy that can be used in order to maintain the flow temperature at any point in the pipeline above wax and hydrate formation region. As shown in [18], at temperature around 288, 15°k, wax will start to form inside the pipeline and at temperature below 313, 15°k, combine with high-pressure gas hydrates will occur. Therefore, it is also important to select the appropriate insulation material and required thickness that will be able to keep the flowing temperature to above 313.15°k. Recently, [3,16-18] among others, have investigated the effect of several insulation materials and several thickness on the temperature profile under steady and transient state condition in order to select and to determine the require thickness of insulation necessary to guarantee a continuous flowing of the fluid inside pipeline. However, most of these studies focuses on the case of single-phase flow and do not considered the pressure drop calculation.

In this study, are objectives are to model under steady state, the temperature profile during oil and gas flow in offshore pipeline and to determine by numerical simulation:

- the effect of oil flow rate change on the temperature profile,
- the effect of several insulation materials and several insulation thickness on the temperature profile
- the optimum operating condition that is, the appropriate insulation material and thickness necessary to meet the requirement temperature of 313.15°k at any point in the pipeline.

II. METHODOLOGY

A. Pipeline Geometry

The pipeline geometry considered in this study is the same as that presented in [1] for the example 1 case. Figure 1 below is a representation of the vertical section of the considered offshore pipeline.

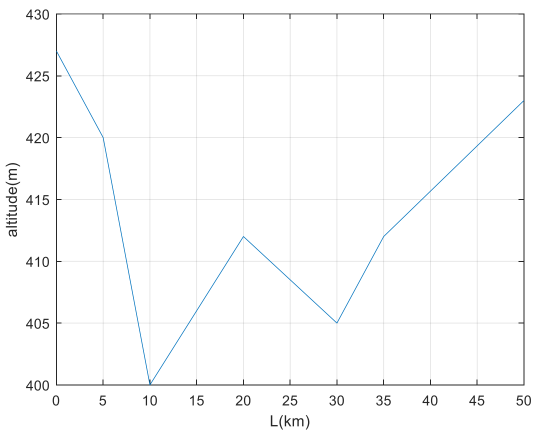

Fig. 1:- Vertical sectional profile of the pipeline [1].

Figure 2 below, show the cross sectional section of the pipeline covered with insulation.

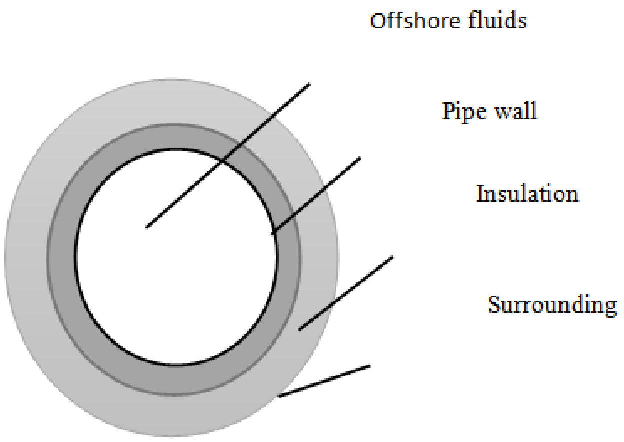

Fig. 2:- Pipeline with insulation material

The pipeline is consisting of a single metal carbon steel covered by coating insulation. The surrounding environment is seawater.

B. Fluids Properties

Fluids properties needs to be determined in order to perform the calculation of the pressure gradient along pipeline. These properties, which are local density, local viscosity, surface tension, local fluids flow rates, formation volume factors and the gas compressibility factor among others, depend on pressure and temperature and are determined using black oil model. In this work, we do not focused on fluids properties calculations but on the temperature calculation. The methodology of the determination of these fluids properties can be seen in the works done by [12], which provides in depth details equations needed for the calculations procedure using black oil model formulation.

C. Abbreviations and Acronyms

The pressure gradient dp/dL, where p is the pressure and L is the length along the pipeline is determined as:

$$\left(\frac{dP}{dL}\right) = \left(\frac{dP}{dL}\right)_f + \left(\frac{dP}{dL}\right)_h + \left(\frac{dP}{dL}\right)_{acc} \quad (1)$$

The first term on the right side of Equation (1), subscript “*f*”, is the pressure gradient corresponding to the friction. The second term with subscripts “h”, correspond to the gravity, and the last term with subscripts “acc”, is relative to the pressure loss due to the acceleration. In this work, the pressure gradient is approximated by using Dukler and Taitel correlation [4] in which, void fraction is determined based on drift-flux model using correlations from [11,23].

$$\left(\frac{dP}{dL}\right) = \frac{f_{tp}\rho_m V_m^2}{2D} + \rho_m g \sin(\theta) \quad (2)$$

where: P is the pressure given in $\mathrm{P_a}$; L is the length of the pipeline in m; ρ_m is the mixture local density in $\mathrm{k_g/m^3}$; v_m is the mixture velocity in $\mathrm{m/s}$; D is the pipeline outer diameter in m; g is the gravitational acceleration given in $\mathrm{m/s^2}$ and θ is the inclinasion of the pipeline expressed in degrees. In equation (2), two necessary variables are to determine:

- f_{tp} is the two phase friction factor determined as in [4].
- ρ_m, which is calculated here using equation (3) below:

$$\rho_m = \rho_L\left(\frac{\lambda^2}{1-\alpha}\right) + \rho_g\left(\frac{(1-\lambda)^2}{\alpha}\right) \quad (3)$$

with, ρ_g, density of the gas, $\mathrm{k_g/m^3}$; ρ_L liquid density, $\mathrm{k_g/m^3}$; α is the void fraction of the gas phase given by drift flux correlation of Woldesemayat. For more details see [12, 26].

$$\alpha = \frac{V_{sg}}{C_d V_m + V_d} \quad (4)$$

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where, V_{sg} is the superficial velocity of the gas phase, m/s; V_m is the mixture velocity, m/s; C_d is the profile parameter and V_d is the drift velocity. These two parameters are calculated as presented in [12] by:

$$C_d = \frac{V_{sg}}{V_m}\left[1 + \left(\frac{V_{sl}}{V_{sg}}\right)^{\left(\frac{\rho_g}{\rho_L}\right)^{0.1}}\right] \quad (5)$$

$$V_d = 2.9\left[\frac{g.D.\sigma(1+\cos\theta)(\rho_L-\rho_g)}{\rho_L^2}\right]^{0.25}(1.22 + 1.22\sin\theta)^{\frac{P_{atm}}{P}} \quad (6)$$

In equation (6), σ, N/m, is the surface tension calculated as presented in the work of [27]. P_{atm}, is the atmospheric pressure, in Pa.

From equation (2), λ is the liquid input fraction and is calculated as follow:

$$\lambda = \frac{Q_{o\ sc}B_o + Q_{w\ sc}B_w}{Q_{o\ sc}B_o + Q_{w\ sc}B_w + (Q_{g\ sc} - Q_{o\ sc}R_s)B_g} \quad (7)$$

where, $Q_{o\ sc}$ and $Q_{w\ sc}$ are oil and water flowrate respectively at standard condition given in m^3/s. Black oil parameters which are: B_w, m³/m³; B_g, m³/m³; B_o, m³/m³; R_s, Sm³/Sm³ are calculated as presented in the work of Andreolli [12].

D. Temperature Model

From the general equation describing the temperature profile along pipeline considering that the kinetic energy is negligible [19] we have:

$$\frac{\partial(T_m)}{\partial t} - \eta_m\frac{\partial P}{\partial t} = -v_m\frac{\partial(T_m)}{\partial L} - \frac{U_o\pi D(T_m - T_e)}{A_p\rho_m Cp_m} + v_m\eta_m\frac{\partial P}{\partial L} - v_m\frac{g\sin(\theta)}{C_{p_m}} \quad (8)$$

where, T_m is the average temperature of the fluid given in °k, A_p is the pipe cross-sectional area m^2, t is the time given in s, C_{p_m} is the mixture specific heat capacity in $J/k_g{}^\circ k$, η_m is the mixture Joule Thomson coefficient, $^\circ k/Pa$, U_o is the overall heat transfer coefficient in $\frac{W}{m^2}{}^\circ k$, T_e is the environment temperature in °k.

In steady state conditions, equation (8) becomes:

$$\frac{dT_m}{dL} = -\frac{U_o\pi D(T_m - T_e)}{C_{p_m}w_m} + \eta_m\frac{dP}{dL} - \frac{g\sin(\theta)}{C_{p_m}} \quad (9)$$

where:

w_m is the mixture mass flow rate in k_g/s, given by:

$$w_m = \rho_m V_m A_p \quad (10)$$

Cp_m, is the average specific heat capacity of the multiphase flow calculated using equations (11) and (12) below as in [28]:

$$Cp_m = Cp_g\alpha\frac{\rho_g}{\rho_m} + Cp_L(1-\alpha)\frac{\rho_L}{\rho_m} \quad (11)$$

$$Cp_L = \left(\frac{Q_o}{Q_o+Q_w}\right)Cp_o + \left(\frac{Q_w}{Q_o+Q_w}\right)Cp_w \quad (12)$$

Where, Cp_g and Cp_L are the specific heat capacity of the gas and liquid respectively. Cp_m, Cp_g and Cp_L are expressed in $J/(kg.{}^\circ k)$. Q_o and Q_w are respectively the local flowrates of the oil and water given by $Q_o = Q_{o\ sc}B_o$, m^3/s and $Q_w = WOR.Q_{o\ sc}.B_w$, m^3/s are the oil and water local flowrate respectively.

η_m, is the average Joule-Thomson, coefficient calculated using equation (13) through equation (16) as shown below,

$$\eta_m = -\left(\frac{w_g Cp_g\eta_g + w_L Cp_L\eta_L}{w_m Cp_m}\right) \quad (13)$$

$$\eta_g = \left(\frac{1}{\rho_g C_{p_g}}\right)\left[\frac{T_m}{Z}\left(\frac{dZ}{dT}\right)_p\right] \quad (14)$$

$$\eta_L = \frac{1}{\rho_L\, Cp_L}(T_m\beta - 1) \quad (15)$$

$$\beta = \frac{WOR}{1+WOR}\frac{\partial B_w}{\partial T} + \frac{1}{1+WOR}\frac{\partial B_o}{\partial T} \quad (16)$$

where, η_g and η_l are respectively the Joule Thomson coefficients of the liquid and the gas given both in $^\circ k/Pa$. β, is the thermal expansion of the liquid phase, $1/{}^\circ k$. Z, is the gas compressibility factor determined by using new correlation presented in [29]. w_g and w_L are the mass flowrate of the gas and liquid phases respectively given in kg/s.

From equation (9), the overall heat transfer coefficient U_o is given by equation (17) below:

$$\frac{1}{U_o} = \left(\frac{r_{ins}}{r_i h_{in}} + r_{ins}\frac{\ln\left(\frac{r_o}{r_i}\right)}{k_{pipe}} + r_{ins}\frac{\ln\left(\frac{r_{ins}}{r_o}\right)}{k_{ins}} + \frac{r_{ins}}{h_o}\right) \quad (17)$$

where, k_{pipe} and k_{ins} represent the thermal conductivity of the metallic pipe and the insulation layer respectively, they are expressed in , $\mathrm{w/(°k.m)}$. r_{ins}, r_o and r_i are respectively the insulation material radius, the outer and the inner radius of the pipeline, all expressed in m.

The surrounding heat transfer coefficient h_o expressed in $\mathrm{w/(°k.m^2)}$, is calculated using equation (18) below:

$$h_o = \frac{K_o Nu_o}{D} \tag{18}$$

where, $Nu_o = 0.027\,.R_{eo}^{0.8} P_{ro}^{0.3}$, represent the Nusselt number; $Re_o = \frac{\rho_o V_o D}{\mu_o}$, is the outer Reynolds number of the seawater; ρ_o is the density of the seawater, $\mathrm{kg/m^3}$; V_o, is the seawater velocity, $\mathrm{m/s}$; μ_o is the viscosity of the seawater, in $\mathrm{Pa.s}$; $Pr_o = \frac{\mu_o Cp_o}{K_o}$, is the Prandtl number of the outer seawater; Cp_o is the specific heat capacity of the seawater, $\mathrm{J/(kg.°k)}$; K_o is the thermal conductivity of the seawater, $\mathrm{w/(°k.m)}$

The internal heat transfer coefficient expressed in $\mathrm{w/(°k.m^2)}$, is calculated according to [24] as follow:

$$h_{in} = \frac{K_{tp} Nu_{tp}}{D} \tag{19}$$

where:

K_{tp} expressed in $\mathrm{w/(°k.m)}$, is the mixture thermal conductivity of the two-phase flow given as

$$K_{tp} = \alpha k_g + (1-\alpha)k_L \tag{20}$$

With k_g and k_L representing each the thermal conductivity of the gas and liquid respectively, expressed both in $\mathrm{w/(°k.m)}$.

Nu_{tp}, the Nusselt number of the two-phase flow determined as follow:

If flow is laminar ($Re_T \leq 2000$), for long pipe, we have:

$$Nu_{tp} = 1.86\left[Re_T Pr_m \left(\frac{D}{L}\right)\right]^{\frac{1}{3}} \tag{21}$$

If flow is turbulent flow ($Re_T \geq 6000$), for long pipe we have:

$$Nu_{tp} = 0.023\,\mathrm{Re_T^{0.8} Pr_m^{0.33}}\left(1+\left(\frac{D}{L}\right)^{0.7}\right) \tag{22}$$

For transition flow regime ($2000 \leq Re_T \leq 6000$)

$$Nu_{tp} = Nu_{laminar}\left[\frac{Re_T}{6000}\right]^a \tag{23}$$

with, parameter a given by:

$$a = \frac{\ln\left(\frac{Nu_{turbulent}}{Nu_{laminar}}\right)}{\ln\left(\frac{Re_{max}}{Re_{min}}\right)} \tag{24}$$

The total Reynolds number Re_T is calculated as follow:

$$Re_T = \frac{\rho_L V_{sL} D}{\mu_L} + \frac{\rho_g V_{sg} D}{\mu_g} \tag{25}$$

The Prandtl number of the mixture is given by:

$$Pr_m = \frac{\mu_m Cp_m}{K_{tp}} \tag{26}$$

The heat exchange between the hot fluids inside pipeline and the cooler environment is given by:

$$q = U_o(T_m - T_e) \tag{27}$$

where, q is the heat flux given in $\mathrm{w/m^2}$.

Numerical Solution

The finite difference method was used to discretize the temperature model given by equation (9). All the equations in this study are solved simultaneously using Matlab software. Pipesim software is used for comparison purpose. Numerically, we divide the pipeline into sections, and each section was divided into cells and consider average value of temperature and pressure in the cells. The numerical solution obtained using finite difference method is therefore given by:

$$\frac{T_m(i+1)-T_m(i)}{\Delta x} = \left(\frac{T_e - T_m}{A} + \eta_m \frac{dP}{dL} - \frac{g\sin(\theta)}{C_{p_m}}\right)_i \tag{28}$$

In which, the parameter A is:

$$A_i = \left(\frac{C_{p_m} w_m}{U_o \pi D}\right)_i \tag{29}$$

The temperature model presented above is first validated by using it to produce the same work done by [1]. The difference done here by this research is the methodology approach for the determination of the pressure gradient, the calculation of the Z-factor, the calculation of the liquid holdup and the determination of the of the joule Thomson coefficient of gas, liquid and thus, for the mixture. The operating parameters used is the same as those presented in table .1 of reference [1].

III. RESULTS AND DISCUSSIONS

In order to analyze the accuracy of the temperature model proposed in this study, the obtained results are to be compared with the results from, UPTP model and measured value (MV) as presented in [1] for the;

Case 1 example.

For that, the same operating parameters and the same pipeline geometry parameters as in [1] have been used in our Matlab computer program. By using this field data, we computed the pressure and temperature profile along the offshore pipeline. Fig. 3 and 4 represents the pressure and temperature profile of the oil and gas flow through offshore pipeline obtained using the proposed model.

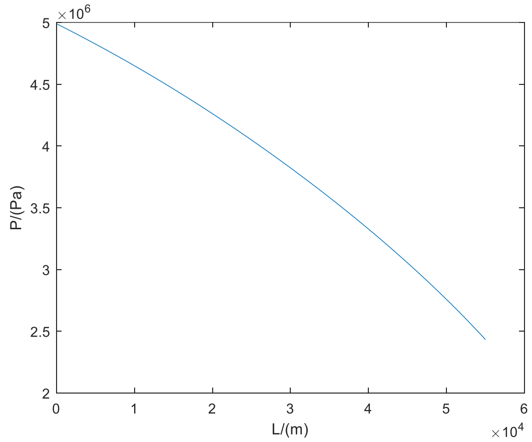

Fig. 3:- Pressure profile of oil and gas flow along offshore pipeline obtained using proposed model.

In fig.3, we observed that the pressure decreases along the offshore pipeline from 5×10^6Pato 2.4327×10^6Pa. Pressure drop is not linear because of the presence of more than phase.

Methods	Inlet pressure/ (MPa)	Endpoint pressure/ (MPa)	Pressure drop /(MPa)	REPD
Model	5	2.4327	2.5673	1.26%
MV	5	2.4	2.6	

Table 1:- Pressure comparison and validation [1].

Table.1 above shows the pressure drop comparison between results from our model and that obtained by measurement.

It comes out that the predicted pressure model matches with the measured value with a relative pressure drop (REPD) of 1.26%.

In fig.4, it is shown the comparison between the temperature profile of the oil and gas flow from our model and that from pipesim model. It can be seen, the temperature decreases along the pipeline for the both model from 323.15°k to an end point value of 278.2861°k for pipesim and 277.9934°k for our model. It is shown that our model prediction matches with the pipesim prediction with a relative error of 0.6%.

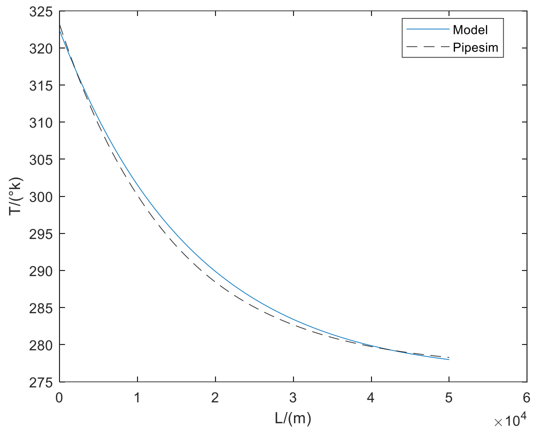

Fig. 4:- Temperature profile comparison between our model and pipesim model.

Table.2 below, presents comparison between the results of the temperature drop obtained from our model, pipesim model, UPTP model and measured value. In this table, the relative temperature drop (RETD) is calculated as follow:

$$RETD = \frac{Temperature\ drop\ predicted - Measured\ Value}{Temperature\ drop\ predicted} \times 100\%$$

It is shown in table.2 below that the result obtained from our model is in good agreement with results from others models and those of the measured value. These results indicates that the accuracy of the proposed model presented here is verified.

From fig.4 above, we also observed that the temperature decreases significantly after the first 1.5 km of flow. This is due to the rapid heat flux exchange between the warm fluid and the cooler environment as can be seen in fig.5 below.

Methods	Inlet temperature/ (°k)	Endpoint temperature/ (°k)	Temperature drop/(°k)	RETD
Model	323.15	277.9934	45.1566	1.68%
Pipesim	323.15	278.2861	44.8669	1.04%
UPTP	323.15	277.25	45.9	3.37%
MV	323.15	278.75	44.4	

Table 2:- Temperature drop validation (MV) as presented in [1]

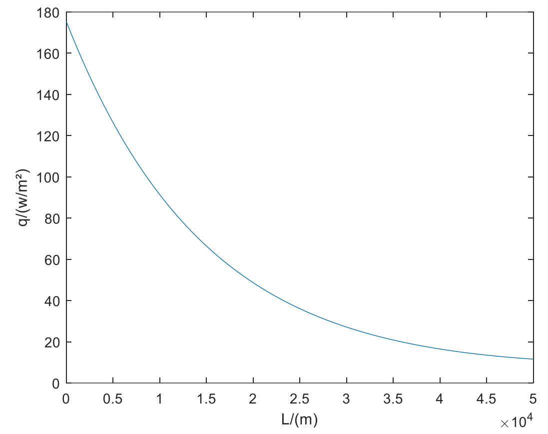

Fig. 5:- Heat flux exchange between the warm oil and gas flow and the seawater environment.

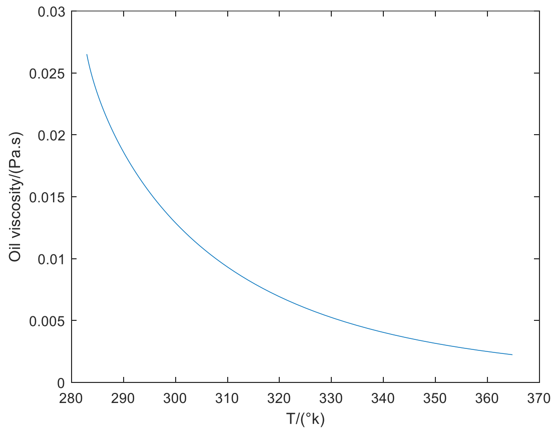

Fig. 6:- Variation of the oil viscosity with the temperature.

In fig.7 below, it is shown that the oil flowrate decreases as the temperature decreases.

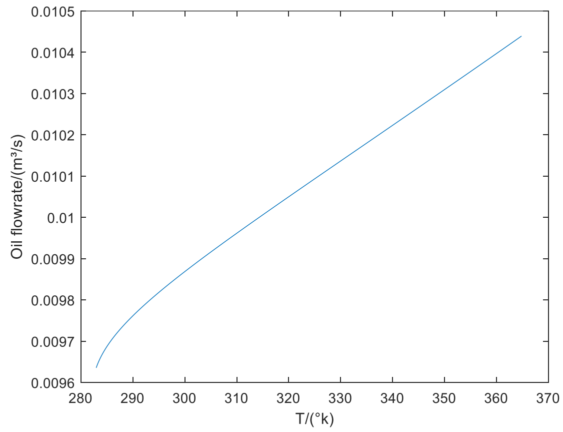

Fig. 7:- Variation of the oil flowrate with the temperature.

By considering the validation of the proposed model, sensibility runs are performed. We first analyzed the effect of three insulation materials, which are black aerogel, calcium silicate and polyurethane foam, with various thickness on the temperature profile. The following conditions were considered: the oil flowrate is maintained to 0.00955 m³/s, the inlet pressure is also fixed at 5MPa. The overall heat transfer coefficient is no longer set fix, but is determined using equation (17). Temperature profile is then calculated for each insulation and various thickness. Results are displayed in fig. 8, 9 and 10 below.

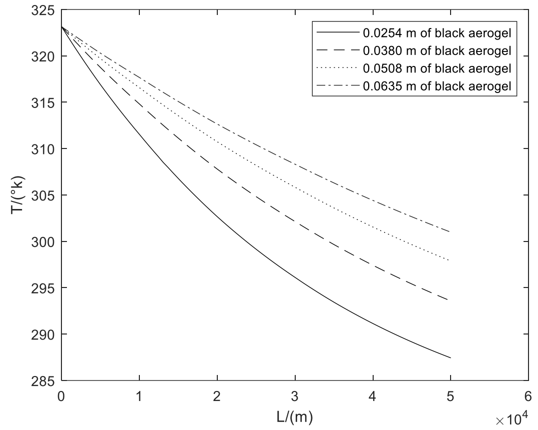

Fig. 8:- Effect of several thickness of black aerogel on the temperature profile of oil and gas flowing through offshore pipeline of 50 km.

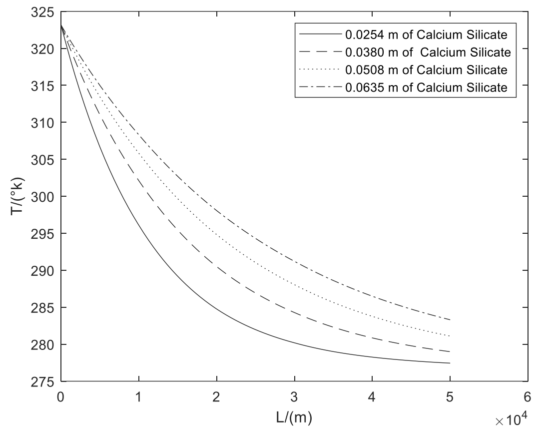

Fig. 9:- Effect of several thickness of calcium silicate on the temperature profile of oil and gas flowing through offshore pipeline of 50 km

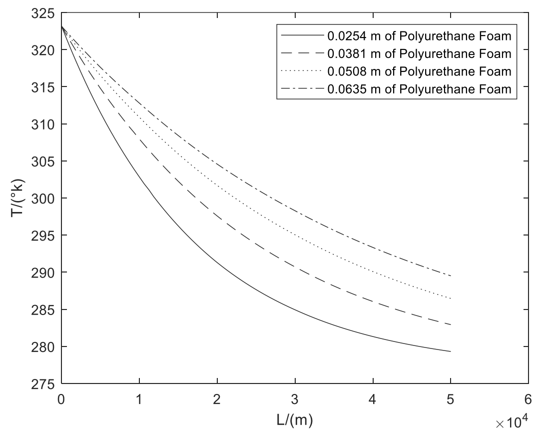

Fig. 10:- Effect of several thickness of polyurethane on the temperature profile of oil and gas flowing through offshore pipeline of 50 km.

It comes out from the figures above that, by increasing the insulation material thickness, the temperature drop decreases along the pipeline. It can also be observed that the black aerogel material provides the best insulation than the others materials because of it very low thermal conductivity. However, none of the insulation material type and the selected thickness is able to withstand the flow assurance requirement.

Effect of the oil flowrate was also investigated. Results showed that as oil flowrate increases, the temperature drop decreases. This is because, increasing oil flowrate, increases the Reynolds number, which influence the overall heat transfer coefficient. Flow becomes rapid and the heat flux diminishes. For the considered range of the oil flowrate, the required minimum of the temperature is not achieve.

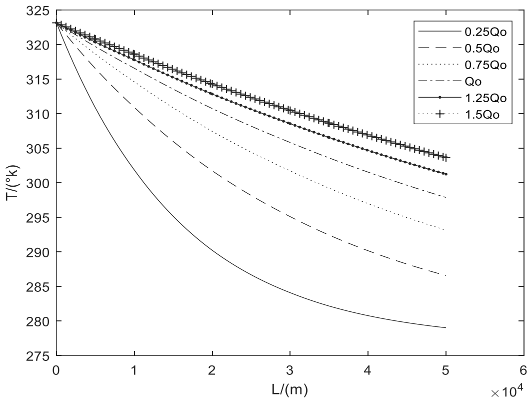

Fig. 11:- Variation of the oil flowrate with the temperature.

Further simulations have been carried out. The insulation material type used is the black aerogel because black aerogel provides better insulation than the others. The thickness selected are 0.0508 m and 0.0635 m, because the selected thickness have great impact on the temperature than the others as has been shown earlier. The oil flowrate is kept constant. The temperature profile for different inlet temperature and different insulation material thickness are calculated. Results are shown in fig.12 and 13 below. It is found that, from fig.12, the selected conditions is not suitable for maintaining the minimum temperature of 313.15°k while in fig.13, for an inlet temperature of 343.15°k with a thickness 0.0635 m, require minimum temperature in at any point in the pipeline is achieved.

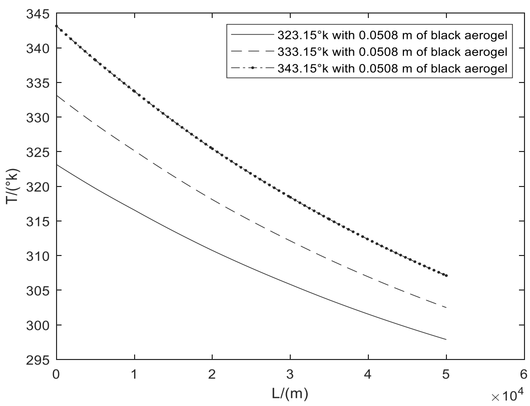

Fig. 12:- effect of different inlet temperature with 0.0508 m of black aerogel on the temperature profile of oil and gas flow in offshore pipeline

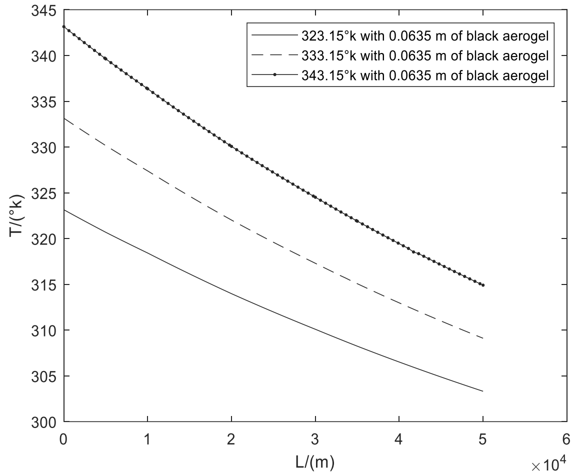

Fig. 13:- effect of different inlet temperature with 0.0635 m of black aerogel on the temperature profile of oil and gas flow in offshore pipeline.

The method presented in this study can be useful for the calculations of the temperature and pressure distribution along offshore pipeline as well as for thermal insulation management.

IV. CONCLUSION

In this paper, a mathematical model is proposed for predicting using numerical simulations, the temperature and pressure profile in long offshore pipeline of length 50 km during transportation of oil and gas. A drift flux model has been used to calculate the liquid holdup and the fluid properties where determined using black oil model. The overall heat transfer is modeled and incorporated in our computer program for sensitivity runs simulations. The results predicted by our model were compared against the results from measured value, UPTP model and pipesim model. Some of the significant points can be listed below:

- Good agreement is found between the predicted model results and field data, UPTP and pipesim models, which proves the accuracy of the model.
- When increasing the thickness of the insulation, the oil flowrate and the inlet temperature individually, the temperature drop decreases to a value below the require temperature at which no flow assurance issues such wax and hydrates formation can be observed.
- For an appropriate couple of inlet temperature and insulation thickness, obtained with a fix oil flowrate and a well-selected insulation material type, optimal operating condition that guarantee a continuous flow of the fluid inside offshore pipeline is achieved

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