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(RESEARCH ARTICLE)

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Effects of ethylene glycol on hydrate formation in subsea pipelines

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Abstract

This study evaluated the effect of Mono-Ethylene Glycol (MEG) on hydrate formation conditions in subsea pipelines for a typical gas deepwater field in Nigeria, using a flow assurance simulator 'PIPESIM'. At the turndown, normal and maximum conditions, the production rates were 1640, 2460, and 3280 sm^3/day, respectively. The wellhead temperature varies between 50-55^{o}C, and the inlet pressure at the wellhead is 25 bara. The outlet pressure at the topside facility must be 11 bara and above to achieve flow. From available flowline internal diameters of 0.24, 0.29, and 0.34m, a simulation was run to determine a suitable internal diameter which will not lead to erosion due to the velocity. In deciding the hydrate formation temperature, the wellhead pressure of 25 bara was utilized to run the estimation. Also, in determining the minimum MEG volume required to achieve flow above a hydrate appearance temperature of 30 °C, a simulation was run at MEG volumes of 0, 10, 20 and 30 wt%. From the simulations, hydrates were observed to form at a temperature of 11.4 °C, at the minimum MEG volume of 30wt%. The 30wt% MEG suppressed the hydrates to a temperature of 8.9 °C. A slug volume of 8.5m3 was observed to be adequate to ensure fluid transport to the topside. This work's outcomes and findings also suggest a flowline inner diameter of 0.29m, an overall heat transfer coefficient of 0.81W/m^{2o}C, and an optimum flow rate of 3280 sm^3/day to avoid temperature drop to be optimum for flow assurance.

Keywords: Flow assurance; Hydrate formation; Mono-ethylene Glycol; PIPESIM

1. Introduction

In the oil and gas industry, hydrates represent an important safety and economic responsibility. Formation of hydrates in natural gas pipelines can form a plug, which can pose safety and operational hazards [1]. The risk of hydrate formation increases with the production of formation water [2]. Casualties occur when plugs break unexpectedly. According to Ng and Robinson, (1985) [3], the research on hydrate inhibitors began as a result of the flow assurance issue of natural gas pipelines. In order to prevent formation of hydrates in pipelines, over half-a-billion dollars is spent annually by the energy industry on measures such as methanol injection [4]. Ethylene glycols can be primarily utilized as thermodynamic hydrate inhibitors to absorb water associated with natural gas, during the production and transport of hydrocarbons [5-6]. Ionic salts can also be utilized for ultra-deepwater projects or mixed with an organic inhibitor (e.g. Mono-ethylene glycol) to boost hydrate inhibition efficiency [7]. Mono-ethylene glycol (MEG) is increasingly preferred over other inhibitors such as methanol because it has a better hydrate suppression performance, with lower gas phase losses, and more operational and environmental friendliness [8, 9]. Carroll (2014) [10] suggested Ammonia as an inhibitor for hydrate formation but considering the large quantity required for operation (i.e. production and transportation of hydrocarbon), the regeneration of MEG is the most reliable and economical method of recycling the used MEG to clean contamination with minimum loss [6, 11, 12]. Now, its usage in Nigeria deepwater fields has not been

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reported despite its proven records in other fields around the globe. With Nigeria having several offshore fields [13], it becomes even of a more concern to get the flow assurance right due to the unfavourable operating conditions offshore.

This work focuses on the multiphase simulation of the subsea flowline of a typical gas field to analyze and be able to predict and manage hydrate deposition and other flow assurance challenges prevalent in subsea operations. The subsea flowline being simulated is designed such that recovered hydrocarbons can be transported from a deepwater manifold to a topside facility. The scope of this study covered only the investigation of the effect of MEG and fluid/flow parameters (of the typical gas field) on hydrate formation conditions using PIPESIM software as a tool for simulation. The software, PIPESIM, was used to simulate the effects of key parameters including MEG on hydrate deposition. PIPESIM simulates multiphase flow starting from the reservoir through the wellhead to the platform.

2. Material and methods

In the case study used for this work, the multiphase fluids flow through 10 km flowlines to a 200 m riser, which connects to the platform (see Figure 1 please).

Figure 1 The Flow model

The data available for this work include operating temperature varying between 50-55^{o}C, well head pressure of 25bara, internal diameters of 0.24m, 0.29m and 0.34m, rate of undulations- 0, horizontal distance of 10,000m, flow rates of 1640, 2460, and 3280 sm^3/day, pipe wall thickness of 0.013m, pipe roughness of 0.025mm, pipeline thermal conductivity of 45 W/m ^{0}C, minimum outlet pressure of 11 bara, optimum pipeline outer diameter of 500mm, ambient temperature of 5^{0}C, hydrate appearance temperature of 26^{0}C and riser elevation of 200m.

The basic tasks in the work are sizing the flow line and pressure-distance profile analysis for the given flow rates, determining that the selected line internal diameter (ID) does not cause Erosional Velocity, estimating the hydrate formation temperature and determining the Overall Heat Transfer Coefficient (OHTC), U for the line. Other tasks are establishing the minimum volume of MEG to keep the fluids above hydrate appearance temperature and prevent hydrate deposition, validating the suitability of the slug catcher capacity for the first stage separator and confirming the probability of severe slugging.

To size the flow line and pressure-distance profile analysis for the given flow rates, the available flowline sizes, that is, for the subsea pipeline and the riser will be utilized. This only applied to the pipeline diameter and does not affect any other layer. An appropriate ID for the flowlines, required to maintain the delivery pressure above 11 bara must be determined and must do so for all production scenarios (maximum, normal and minimum).

To determine that the selected line ID does not cause Erosional Velocity, the Erosional Velocity maximum needs to be estimated using API RP 14E formula (API recommended practice for design and installation of offshore production platform piping systems);

$$V_m^* = 1.22 * \frac{C}{\sqrt{\rho_m}} \text{ .... } (1)$$

Where; $_m{}^*$ is Erosional Velocity maximum (m/s), C = 100,
ρ_m = mixture density (kg/m^3) and is provided in PIPESIM output file.

In order to confirm that a flowline does not have issues with erosion, the maximum erosional velocity ratio, EVR must be less than one (1).

2.1. Estimation of hydrate formation temperature and determination of OHTC

This involves iterations with charts at a constant pressure of 25 bara, changing temperatures and estimating K values for the hydrocarbon componentsC_1, C_2, C_3, IC_4 and nC_4 [14]. The hydrate formation temperature is the temperature that results to:

$$\Sum(^y/_K) = 1 \text{ .... } (2)$$

Where; y is the vapour mole fractions of the hydrocarbon components obtained from PIPESIM.

These hydrocarbon components, that is: C_1, C_2, C_3, IC_4 and nC_4 have infinite K values. The hydrate formation temperature and Hydrate Appearance Temperature will be weighed against each other and the greater of the two will be utilized as the minimum outlet temperature. A safety margin of 4°C will be added to the hydrate appearance temperature making it 30°C. The overall heat transfer coefficient is obtained through the Equation (3):

$$U = \frac{(m * C_{pn})}{A} * In \left[\frac{(T_1 - t_1)}{(T_2 - t_1)}\right] \text{ .... } .(3)$$

Where; m is the mixture mass flow rate (kg/s),
C_{pn} is the mixture specific heat capacity (J/kg-°C),
A is external flowline area (m^2),
T_1 is inlet temperature of the pipe/flowline (°C),
$T_2$is outlet temperature of the pipe/flowline (°C),
t_1 is surrounding flowline temperature, that is, seabed temperature (°C).
C_{pn} and A are obtained from the following equations:

$$C_{pn} = (C_{pl} * H_l) + (C_{pg} * (1 - H_l)) \text{ .... } (4)$$

$$A = \pi D_o L \text{ .... } (5)$$

$$D_o = D_i + 2(t) \text{ .... } (6)$$

Where; C_{pg} is the gas specific heat capacity (J Kg^{-1}°C^{-1}), C_{pl} is the liquid specific heat capacity (J Kg^{-1}°C^{-1}), H_l is liquid holdup, D_o is flowline outer diameter, D_i is inner diameter of flowline, t is flowline wall thickness, L is length of the flowline. m, H_l, C_{pg}, and C_{pl} are obtained from the PIPESIM output file.

In establishing the minimum volume of MEG to keep the fluids above hydrate appearance temperature and prevent hydrate deposition, simulations were carried out to determine the appropriate volume of MEG that will keep the fluids above the hydrate appearance temperature during the lifetime of the field. To do this, four sensitivity analysis were done at 0wt%, 10wt%, 20wt% and 30wt% of MEG respectively. The effect of the different volumes of MEG on the temperature profile of both the pipeline and riser were determined. The minimum MEG volume that keeps the output temperature of the flowlines above hydrate formation temperature is the minimum volume of the MEG.

Validating the suitability of the slug catcher capacity for the first stage separator and confirming the probability of severe slugging, the following correlation was used [15],

$$\ln(L_m) = -2.663 + 5.441\,[\ln(d)]^{0.5} + 0.059[\ln V_m] \text{.........................} (7)$$

Where; L_m = Average slug length in feet,
d = Line internal diameter (inches),
V_m = Mixture velocity (ft/sec).

$$V_m = V_{sl} + V_{sg} \text{ ....} (8)$$

V_{sl} and V_{sg} are the velocities of the liquid and gas phases respectively and are gotten from PIPESIM.

The average length of slug will be multiplied by the area of flowline in order to estimate the slug volume. If the calculated volume is less than the slug catcher capacity of the separator of 8.5m^3, the catcher capacity is appropriate, if not, it is not appropriate and requires further work. The conditions for severe slugging were evaluated too. The conditions include:

Topography: the flowline should have elevation drop on approaching the riser,

Flow Pattern: the flow must be stratified on getting to the riser. The flow pattern will be determined from PIPESIM. The severe slugging number is less than unity ($\prod_{ss} < 1$). The severe slugging number is estimated using Equation (9),

$$\prod_{ss} = \frac{(^{dP}/_{dt})_{pipe}}{(^{dP}/_{dt})_{riser}} = \frac{(^{Z_m * R * T}/_{M * G_g})}{(g * L_{pipe} * (1 - H_l) * G_l)} = \left(\frac{P * U_{sg}}{g * L_{pipe} * (1 - H_l) * \rho_l * U_{sl}}\right) \text{ ....} (9)$$

Where; P is inlet pressure, g is acceleration due to gravity, U_{sg} is gas superficial velocity (m/s), U_{sl} is liquid superficial velocities (m/s) and ρ_l is liquid density (kg/m^3). The parameters U_{sl}, U_{sg}, H_l, and ρ_l were obtained from PIPESIM.

3. Results and discussion

3.1. Flowline sizing

Figure 2 illustrates that the flowline sizes that will meet the output pressure needs are 0.29m (11.417in) and 0.34m (13.386in). The green line in Figure 2 shows that the 0.24m (9.4488in) flowline will not meet this when the field is operating at its maximum flow rate of 3280 Sm^3/day (20631sbb/day) as its outlet pressure is below 11 bara. This implies that the 0.24m flowline will be discarded in the remaining analysis.

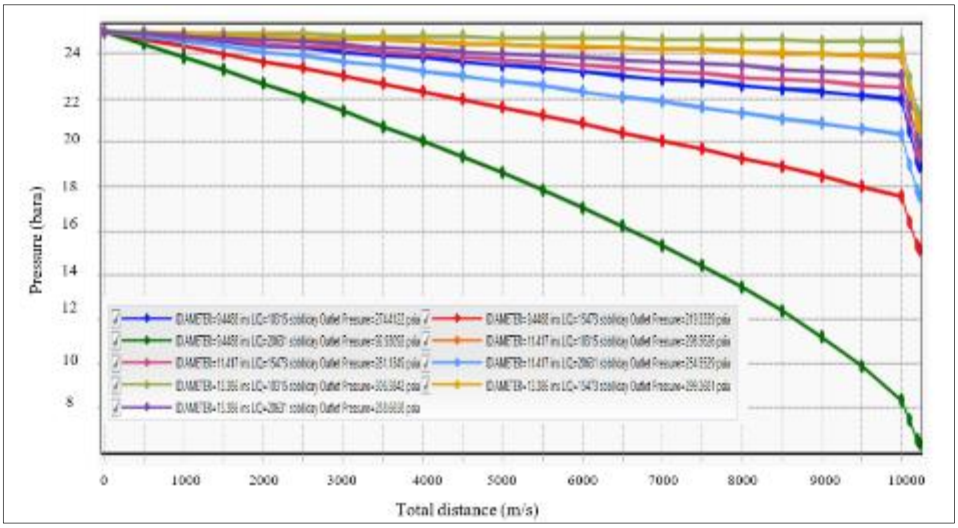

Figure 2 Output Pressure against Distance for all the flowline Diameters

3.2. Erosion Screening

Based on the erosional velocity ratio plot (Figure 3), line size of 0.24m has the highest erosional tendency when compared to line sizes of 0.29m and 0.34m whose ratios are much lesser. This makes them more suitable from erosional velocity perspective.

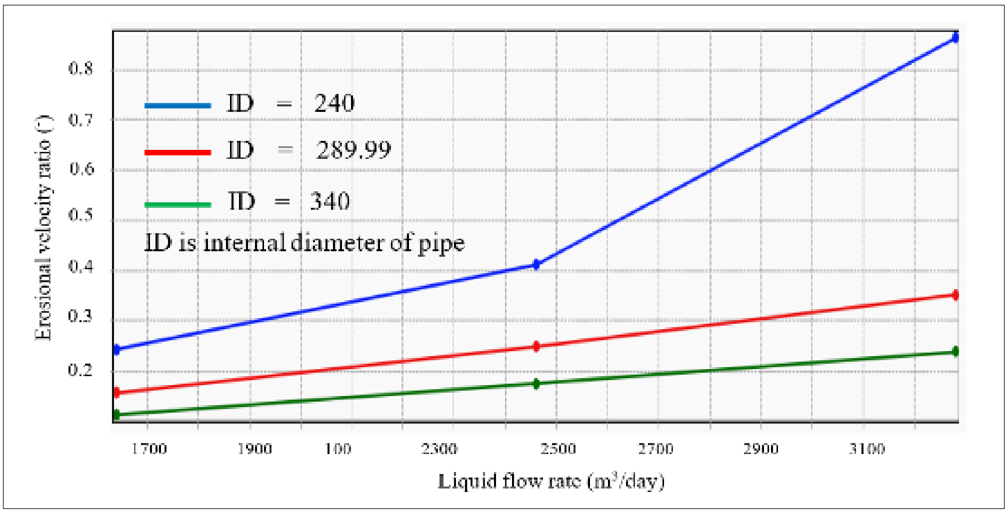

Figure 3 Erosional velocity ratio maximum against the different flow rates

3.3. Hydrate Formation Temperature (HFT)

It is known that with a lower overall heat transfer coefficient, lower temperature drop in the flowline is expected. From the Katz chart, hydrate formation temperature of 11.4^{o}C was estimated and using a pressure of 25bara, a value of U = 2.60079W/m^{2o}C was estimated with PIPESIM, these values met the hydrate formation conditions for the gas compositions. The hydrate appearance temperature of 30^{o}C was used as the temperature for estimating U, which gave a value of 0.81W/m^{2o}C. A safety factor of 4^{o}C was added to the hydrate appearance temperature of 30^{o}C keep the flowline out of the hydrate deposition zones.

3.4. Determination of the Minimum Volume of MEG

First, simulation was performed to ascertain the temperature profile for 0 wt% MEG for the flowline only. This was followed by those of 10%, 20% and 30% respectively for both the flowline and the riser. The temperature profile with distance for 0 wt% MEG is shown in Figure 4. The temperature profile along the flowline and the riser for 10 wt% MEG are presented in Figures 5 and 6, those of 20 wt% are presented in Figures 7 and 8 while for 30 wt%, the temperature profiles along the flowline and the riser are shown in Figures 9 and 10 respectively.

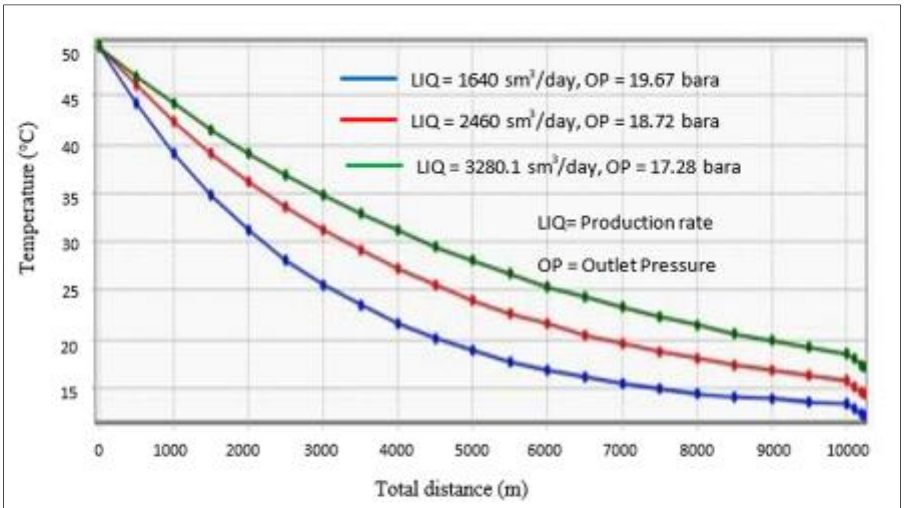

Figure 4 Temperature profile across the flowline for 0wt% MEG in the pipeline

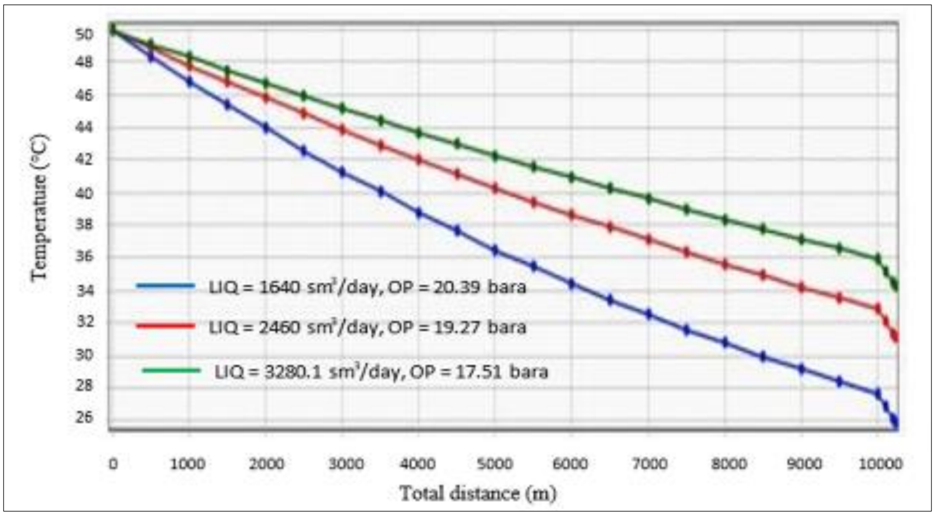

Figure 5 Temperature profile along the flowline with MEG (at 10wt %)

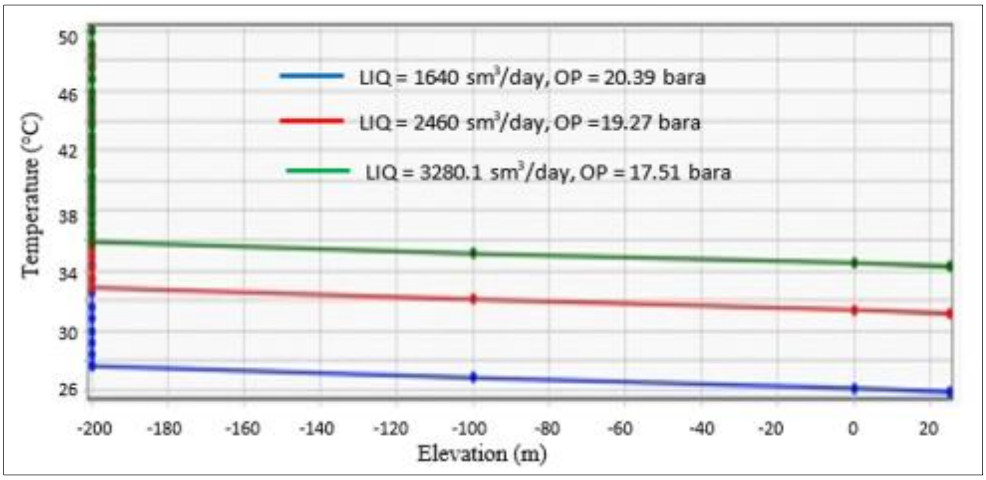

Figure 6 Temperature profile along the riser with MEG (at 10wt %)

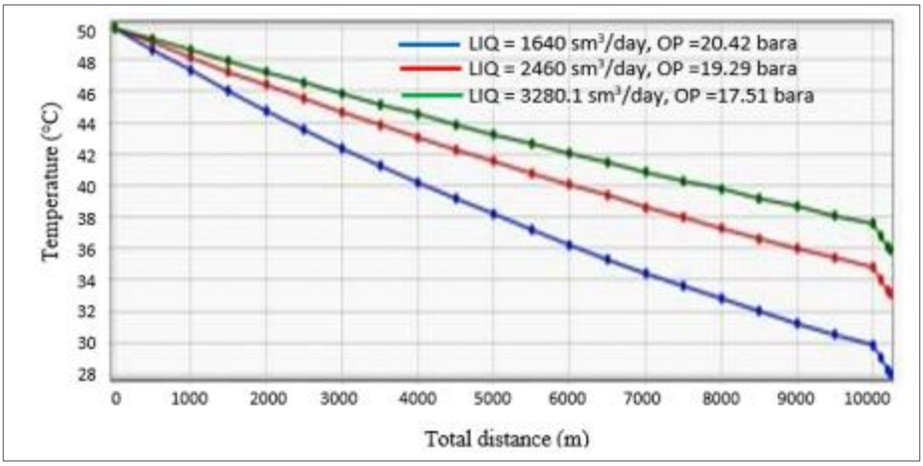

Figure 7 Temperature profile along the flowline with MEG (at 20wt %)

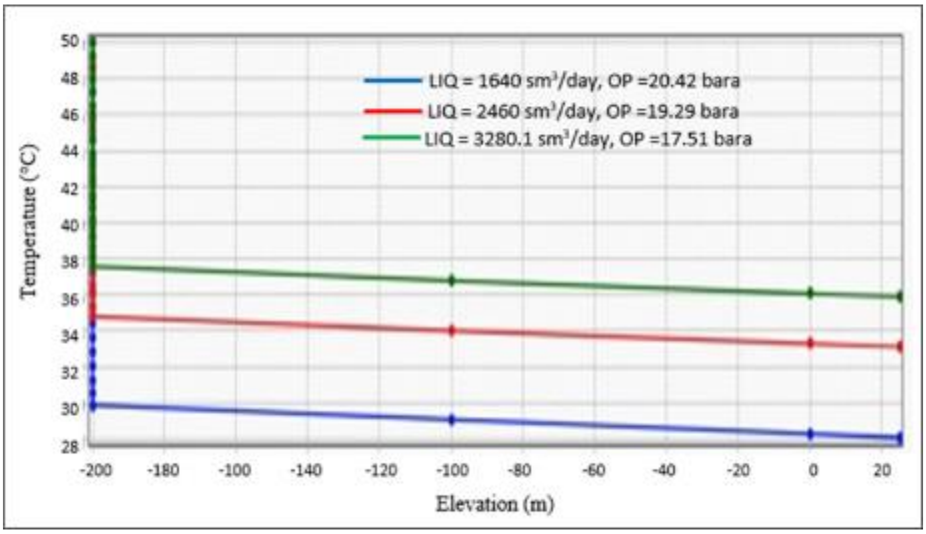

Figure 8 Temperature profile along the riser with MEG (at 20 wt%)

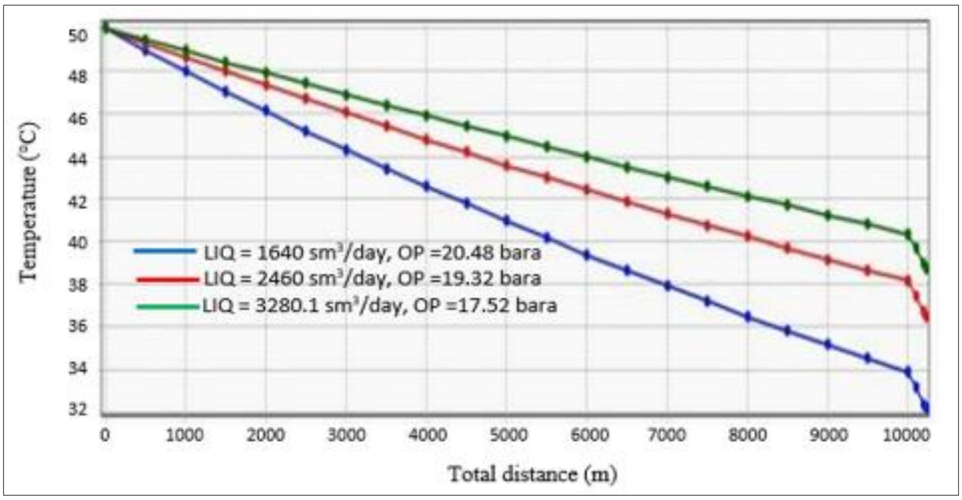

Figure 9 Temperature profile along the flowline with MEG (at 30wt %)

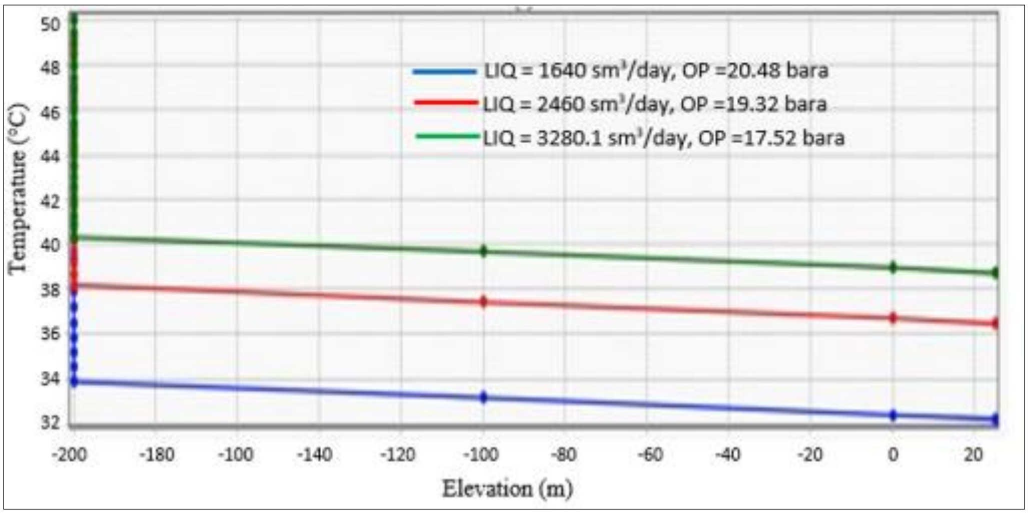

Figure 10 Temperature profile along the deepwater riser with MEG (at 30wt %)

Figure 4 depicts that without MEG, the hydrocarbon stream will fall below the hydrate appearance temperatures. Figure 5 shows that MEG at 10wt% volume is unable to keep the hydrocarbon stream above hydrate appearance temperature for the minimum flowrate. There is a slight drop below the hydrate appearance temperature at the riser base and in the riser. From Figure 6, it can be observed that the fluid reaches the platform at about 26°C which is the hydrate appearance temperature. This does not meet the safety margin criteria of 30°C. As a result, the volume of MEG was increased to 20wt% and simulation was carried out. Figure 7 shows the temperature profile along the pipeline for this MEG volume condition. Considering the 20wt% of MEG, it can be seen that this will not still be enough to meet the safe operation requirement of above 30°C. This is further proven by the plot for the temperature profile along the deepwater riser using 20wt% of MEG. This is shown in Figure 8.

From Figure 8, the output temperature at the topside facility is about 28°C which still does not meet the safe output temperature requirement of 30°C. Thus, a higher volume of MEG is considered. Considering MEG at a 30wt % volume, Figures 9 and 10 are obtained for temperature profiles along the pipeline and along the deepwater riser respectively. Figures 9 and 10 show that MEG at 30wt % volume is sufficient for safe operation above the hydrate appearance temperature, and safe operating temperature of 30°C. This is therefore chosen as the minimum volume of MEG for the typical gas field. The least flow rate of 1640 sm^3/day was also satisfied by this MEG volume since it is the flowrate with the highest tendency of causing excessive temperature loss.

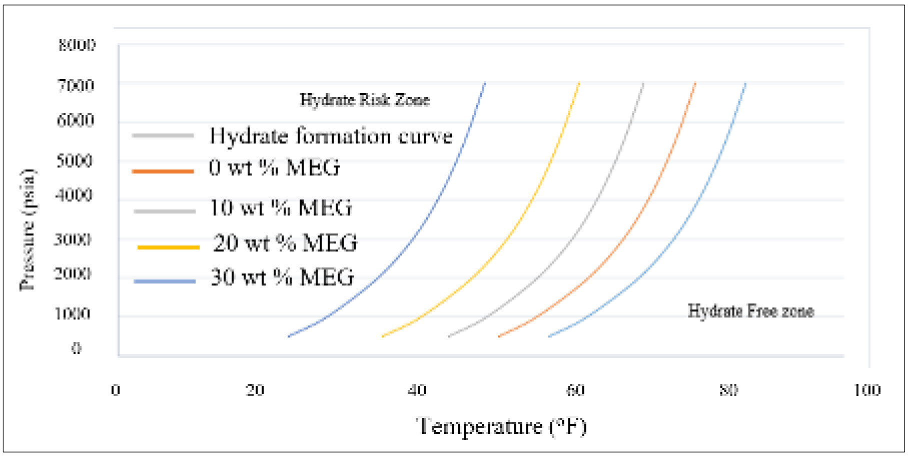

Figure 11 Hydrate Formation curve with varying MEG concentration

From the figure 11, while the field operates at a temperature of about 50-55 °C, hydrates will form at a temperature of about 30 °C (86°F). As the weight of MEG is increased, the hydrate formation curve shifts towards the left, thereby increasing the hydrate free zone. At 30 wt%, hydrates were suppressed to a temperature of about 8.9°C (48°F).

3.5. Terrain Induced Slug Prediction

This analysis was done with the correlation in Equation (7). It was utilized to calculate the length and volume of slug as shown in Table 1 and the tendency for severe slugging was ascertained.

Table 1 Length, volume and severe slugging number for the highest and lowest flow rates

Flow rates (sm^3/d)	Length of slug (m)	Volume of slug (m^3)	Severe slugging number
1640	153.68	7.01	0.19
3280	116	7.82	0.29

The mean slug lengths (m) and volumes (m^3), flow patterns upon reaching the riser and severe slugging numbers for flow rate of 3280sm^3/day are provided in Table 2.

Table 2 Average slug length, volume and slugging number for flow rate of 3280sm^3/day

Property	**Value**
Flow rate	3280sm^3/day
Slug length	135m
Slug volume	7.82 m^3
Flow pattern	Intermittent
Severe slugging number $\prod_{ss}$	0.24

From the Terrain induced slugging outcomes, as a result of the zero undulation assumption, terrain induced slugging cannot be experienced but there will be intermittent flow as ascertained from PIPESIM output file in the upstream section with stable flow in the downstream section.

Thus, the slug catcher of 8.5m^3 is adequate since it is greater than the mean slug volume for both minimum and maximum flow rates. Furthermore, since the severe slugging number for these flow rates are less than one, severe slugging will not occur.

4. Conclusion

The typical gas field fluid was successfully simulated to meet the constraints of delivery pressure, erosion screening, hydrate-free flow involving the selection of the minimum volume of MEG. Hydrate formation temperature for the gas field was computed using Katz model to be 11.4 ^{o}C while the Hydrate Appearance Temperature was found to be 26 ^{o}C. The appropriate MEG volume required to keep the fluid stream above 30^{o}C (considering a safety temperature range of 4 ^{o}C) was 30wt%, while suppressing the hydrates to a temperature of 8.9°C. The wellhead pressure of 25 bara was used in the Katz computation for hydrate formation temperature. A slug volume of 8.5m^3 was observed to be adequate to ensure the transport of fluid to the topside. The outcomes and findings of this work also suggests a flowline inner diameter of 0.29m, an overall heat transfer coefficient of 0.81W/m^2 ^{o}C, and an optimum flowrate of 3280 sm^3/day that will avoid temperature drop to be optimum for flow assurance.

Compliance with ethical standards

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Disclosure of conflict of interest

All authors would like to state that there is no conflict of interest pertaining to this research work.

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