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Designing a Subsea Pipeline System Using PIPESIM Software

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Abstract. Offshore oil and gas production accounts for about 30 percent of the world oil and gas. Transporting produced oil and gas from offshore to onshore facilities is a challenging task for many oil and gas companies due to the hostile environment that offshore has. This paper aims to use PIPESIM software to design a subsea pipeline system that ensures the flow of oil and gas from wellhead to platform. Pipeline diameter, erosion check, hydrate formation determination, insulation, slugging and pressure drop were determined.

Keywords: Subsea, PIPESIM software, Flow assurance.

1. Introduction

Oil and gas production from offshore plays an important role in the world's energy supply [1]. In order to efficiently manage the production of oil and/or gas from the reservoir to wellbore and eventually to surface facilities, a number of flow assurance tasks must be done [2]. Flow assurance tasks are performed by using software called PIPESIM, developed by Schlumberger Company [3].

This software will be used to apply different aspects of flow assurance such as multiphase flow in flow lines, riser and subsea pipelines; pressure and temperature profiles, hydration and wax formation, slugging, erosion and heat transfer coefficients analysis. Objectives of the study case include:

- Selection of suitable pipeline diameter.
- Erosion check of the selected pipe diameter.
- Hydrate formation determination using K method and other methods.
- Insulation configurations.
- Terrains induced and sever slugging using Scott, Shoham and Brill method.
- Pressure drop related to the increase in water cut and whether lift gas is needed.
- Discussing operational modes regarding pipeline architecture.

Today, companies and researchers use PIPESIM software to identify flow assurance problems that may accrue during the process of transporting oil and/or gas from the manifold to the platform. Such problems include choosing the wrong pipeline diameter, hydrate formation, and slugging [2][4]. Previous and similar work were done on flow assurance using PIPESIM software titled : Subsea Pipeline Design For Natural Gas Transportation: A Case Study Of Côte D'ivoire's Gazelle Field in 2018 [5] and Flow Assurance in Subsea Pipeline Design - A Case Study of Ghana's Jubilee and TEN Fields in 2019 [6]. Both research papers use PIPESIM to perform different tasks of flow assurance on two different fields.

What this paper has in common with the above mentioned papers is the use of PIPESIM software which is very common in oil and gas research papers. However, the case study of this paper and data are genuinely different. The importance of this paper is to help engineers to understand how PIPESIM software can be used to choose the right pipeline diameter that will transport hydrocarbons with no problems as described above.

2. Base Data

Base data used to carry out this study are shown in table 1. In addition Fig. 1 shows the schematic layout of the case study.

Table 1. Base data required to carry out the given tasks.

Boundary conditions	Data	Components	Mole %
Fluid inlet pressure at wellhead	24.1 bar	Methane (C1)	36.50
Minimum arrival pressure at the processing platform	10.3 bar	Ethane (C2)	4.40
Fluid inlet temperature at wellhead	50 °C	Propane (C3)	2.60
Ambient sea temperature	4°C	Isobutane (IC4)	0.63
Minimum arrival temperature at the processing platform	tba	Butane (NC4	0.13
Was appearance temperature	25 °C	Isopentane (IC5)	0.67
Total flow rate of four wells	3280 sm3/day	Pentane (NC5)	0.83
Maximum turndown	820 sm3/day	Hexane (NC6)	2.70
Pipe sizes available	241 mm,292mm and 343 mm	C7+	51.54

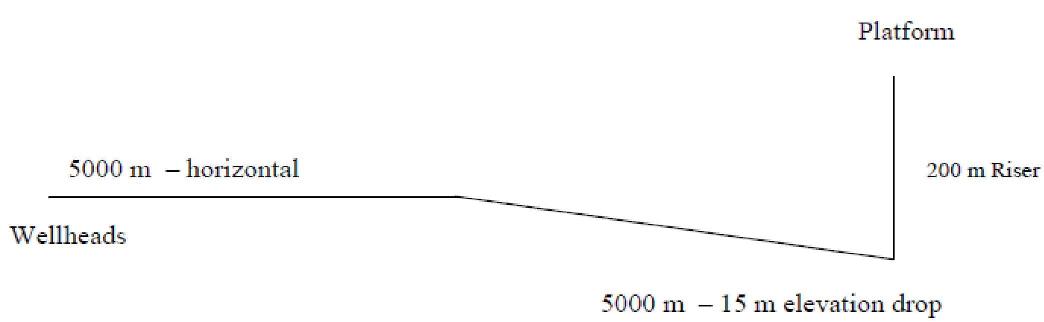

Fig.2. Layout of proposed case study.

3. Flow Assurance Concepts

3.1. Erosion

Erosion is very serious problem in pipelines, risers, manifold and processing facilities [7] .In order to identify the point at which erosion occur, a critical value of velocity should be determined according to API RP 14E defined critical velocity. The critical velocity can be determined from the following empirical equation:

$$V_m^* = 1.22\, {}^{C}\!\big/\!{}_{\sqrt{\rho_m}} \quad (1)$$

Where:
V_m^* = maximum velocity (ft/s);
C= constant typically 100;
ρ_m= no-slip mixture density at operating temperature and pressure (lb/ft^3)

3.2. Hydrate Formation

Hydrate formation is also one of flow assurance problems that cause pipeline plugging and therefore decrease production and cost companies money to pig or inject inhibitors to solve hydrate formation problems [8] .K-value method (equation 2) is used to predict hydrate formation which then use k value to calculate hydrate temperature and pressure.

$$Kvs = \frac{y}{x} \quad (2,a)$$
$$\sum_{i=1}^{i=n} \frac{y}{Kvs} = 1 \quad (2,b)$$

Where: y= mole fraction of vapour; x=mole fraction of liquid.

3.3. Heat Transfer Coefficients

Over all heat transfer coefficient (U) was determined to establish insulation level and maintain temperature of the flow inside pipeline [9]. The following equation was used:

$$\frac{1}{U} = \frac{rp}{rihi} + \frac{rp\ln(\frac{rp}{ri})}{kp} + \frac{rp\ln(\frac{r1}{rp})}{k1} + \frac{rp\ln(\frac{r2}{rp1})}{k2} + \frac{rp}{r2ha} \quad (3)$$

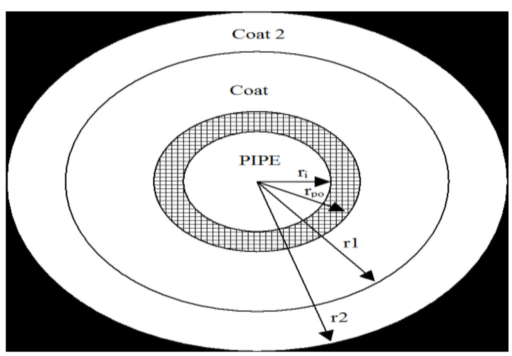

Fig. 1. Cross sectional area of pipe at which equation 3 is based on.

3.4. Terrain Induced Sever Slugging

- Scott, Shoham and Brill (SSB) correlation is used to determine the growth of slugging in pipelines [10]. The SSB correlation is defined as follows:

$$\ln(L_m) = -2.663 + 5.441[\ln(d)]^{0.5} + 0.059[\ln(V_m) \quad (4)$$

Where: L_m = mean slug length(ft); d =pipe diameter($inch$); V_m = mixture velocity (ft/sec) and it is defined as follows:

$$V_m = V_{sfg} + V_{sfl} \quad and \quad V_{slug} = L_m \times A$$

- Sever slugging is used to determine the degree of slugging in flow lines and risers [10].Sever slugging appears when sever slugging number (Πss) is less than 1.Sever slugging number is defined as follows:

$$\Pi ss = \frac{(\frac{dp}{dt})flowline}{(\frac{dp}{dt})riser} \qquad (5)$$

4. Methodology

4.1. Flow Model

The first step was to construct the model .This was done by adding a source followed by setting a boundary node then a node was added. Now, a flow line was connected between the source and the node .Then, a riser was connected vertically between the node and the boundary node. Finally a report was set at the top of the riser. Now, pressure and temperature of 24.1 bara and 50 C respectively were entered to the source (manifold) by double clicking on the source. In the same way the relevant data for the flow line and raiser were entered. The final model is shown in Fig. 3. Before processing any further with the tasks, Beggs and Brill revised correlation were used for both the vertical part and the horizontal part of the model.

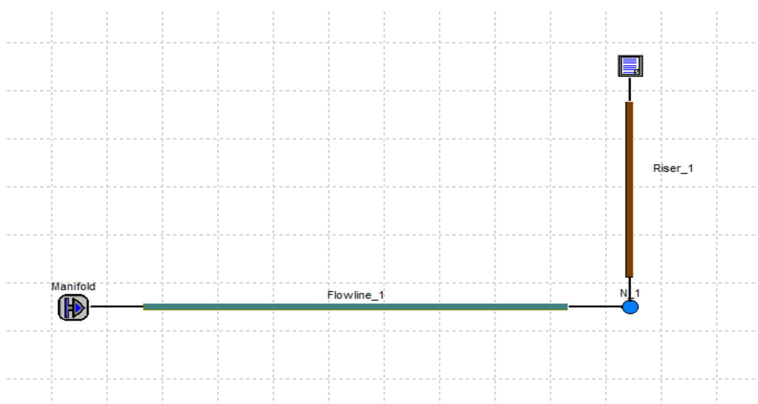

Fig.3. Completed flow model.

4.2. Compositional model

The compositional model Fig.4 was generated by entering the pure hydrocarbon components shown in table 1 above from the PIPESIM library and after adding all the components, the petroleum fraction C7+ was added by entering its values of boiling point, molecular weight and specific gravity. Then the C7+ moles were added to the pure hydrocarbon components. Initial water component was put zero.

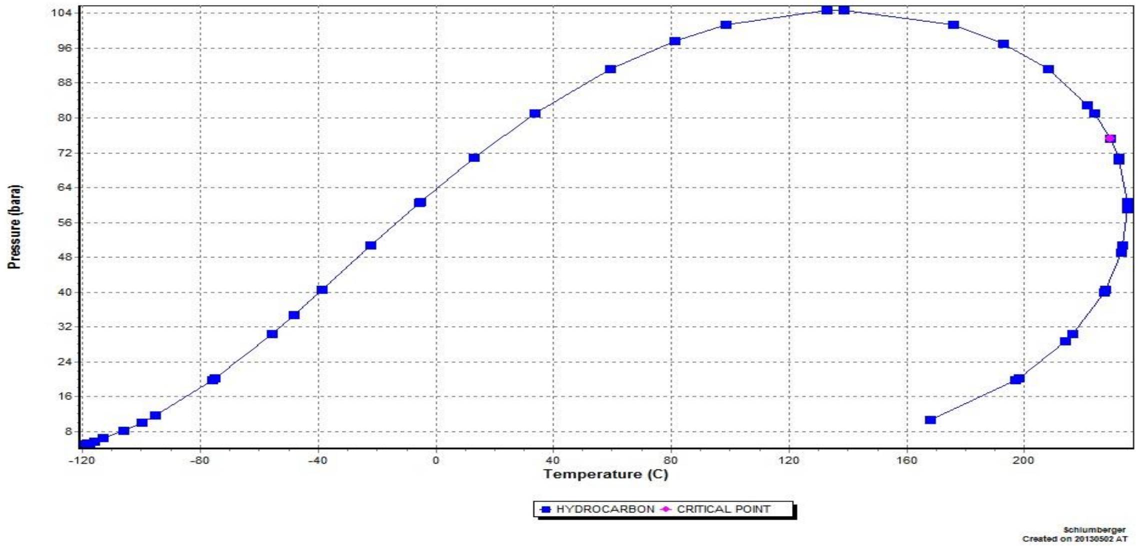

Fig.4. PT phase envelope diagram.

4.3. Pipeline Diameter Selection

Three pipeline diameters 241 mm, 292 mm, and 343 mm were tested to select the most suitable pipe diameter that would transport the condensate from the manifold to the platform without problems. This is done by selecting operation/system analysis and then outlet pressure was selected .After that the flow rates 820,1640,2460 and 3280 sm3/d were entered in the x-axis and the three diameters were entered for both the flow line and the riser. The sensitivity variable was selected as change in step with Var 1 then the model was run. Fig. 5 shown in the result section was generated to select the suitable diameter .In addition, pressure versus total distance graphs (Fig. 6 for the 292 mm and fig.11 the 241 mm in Appendix A) were generated to confirm our diameter selection as a function of distance.

4.4. Erosion Check

API RP 14E erosional check was performed by PIPESIM and by using an empirical equation 1 to confirm the best diameter size that would satisfy erosional criteria .This was done by selecting operations/system analysis and then the model was run to generate erosional velocity ratio maximum versus liquid rates as shown in Fig. 7. Also, equation 1 was used to get an empirical maximum allowable erosion velocity values for the three diameter sizes for comparison purpose.

4.5. Hydrate Formation /Insulation Level Establishment

- First k -values were obtained at different pressures and temperatures for the four different flow rates (table 7 Appendix C) .These data were used to determine hydrate formation conditions. Then, from operations, pressure/temperature profile, pressure versus total distance was selected and the model was run. Then pressure versus temperature diagram was generated to use its data to generate Fig. 8.

- The same steps were repeated as above but this time an insulation level was introduced to the 292 mm diameter pipe. However, this time U value was iterated to yielded U value that was close to 1 W/m^2 K.

4.6. Insulation Configuration Establishment

The insulation was determined by calculating pipe wall thinness insulation based on theoretical analysis (equation 3) and form PIPESIM. Calculations are shown in table 8 and 9 Appendix D.

4.7. Terrain induced /server slugging

Terrain induced value was conducted by using Scott, Shoham and Brill correlation from equation 4 and sever slugging from equation 5 .Then, PIPESIM sever slugging value was generated for comparisons purposes . Detailed calculations are shown in table 10, 11 and 12 Appendix E.

4.8. End of Field Life 90% Water cut

This task was done by changing water content from 0 % to 90% from setup/compositional (local default) then, from compositions, pressure/temperature profile and then model was run. A pressure vs total distance graph was generated as shown in Fig. 10.

5. Results and Discussion

5.1. Pipeline Diameter Selection/ Erosion conformation

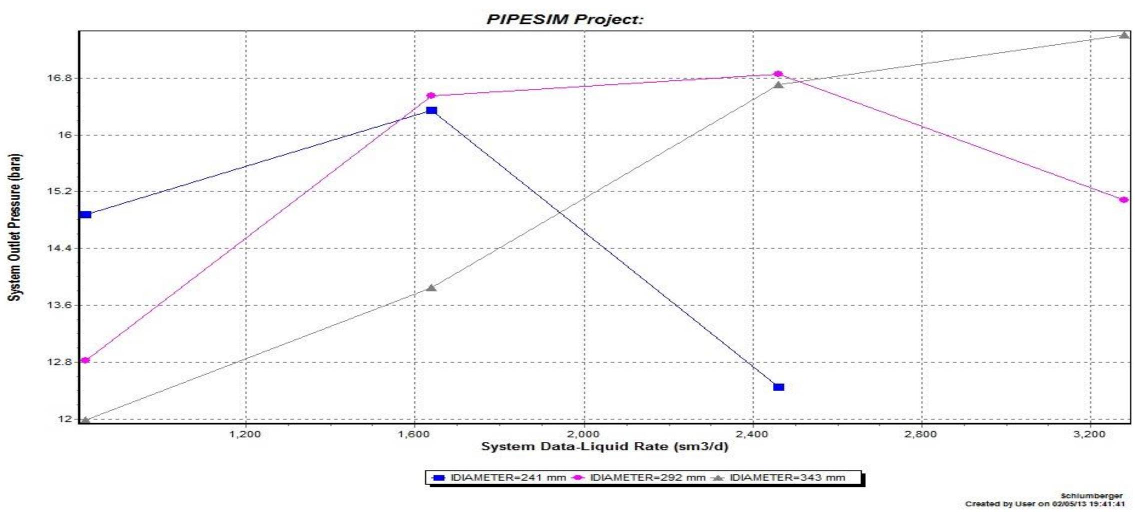

Fig.5. Pipe sizes selection as a function of system outlet pressure versus liquid flow rate.

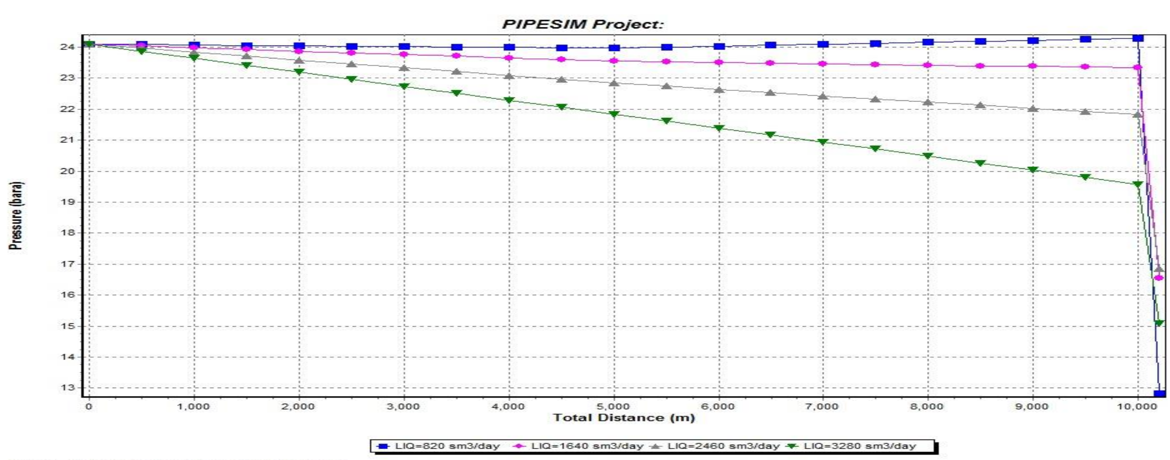

Fig.6. Pressure versus total distance at different flow rates using the 292 mm diameter pipe.

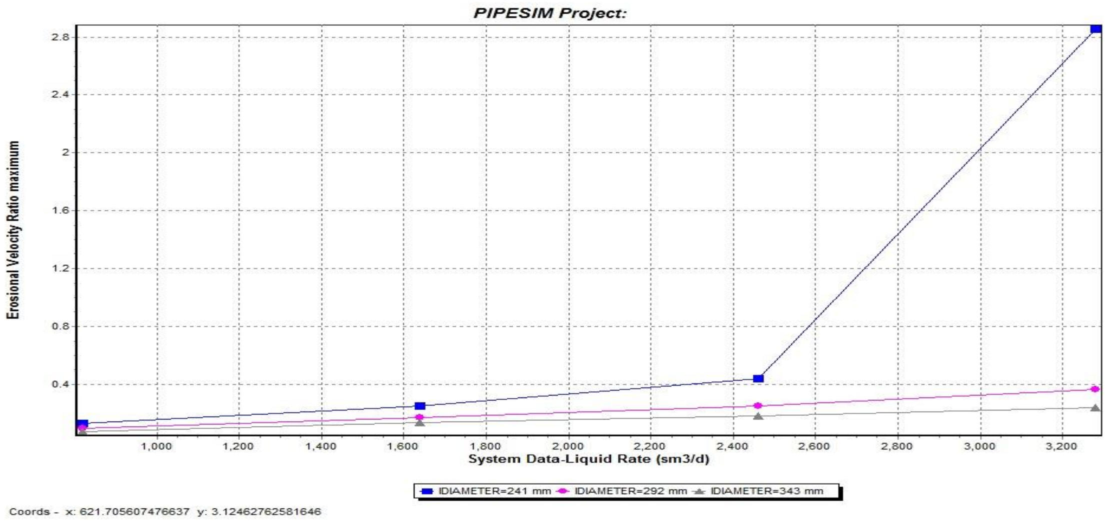

Fig.7. Erosional velocity ratio maximum versus liquid rates to confirm the most suitable pipe size.

Table 2. Final summery results for pipe size selection and erosion viewpoint.

Pipeline size (mm)	Result based on PIPESIM & Calculations
241	Not suitable
292	suitable
343	suitable
Final diameter selection based on economical point of view	292 mm

Table 3. Final summery result for the maximum velocity obtained by PPIESIM and by calculations.

Q (sm3/day)	$\rho_{m(\text{No-slip})}$ (kg/m3)	Calculated,Vm (ft/m)	Vm PIPESIM (ft/m)
820	95.75	12.467	12.50
1640	123.645	10.971	11.00
2460	117.5154	11.254	11.25
3280	101.6515	12.100	12.10

As can be seen from Fig.5, the following points are obtained:

- For the pipeline with the smallest I.D of 241mm, it can be noticed that the pipe I.D will not allow the transportation of 32800 sm3/d of condensate from the manifold to the surface at the platform. This is simply because the pressure in the 241 mm pipeline is low and will only transport flow rate up to 2400 sm3/d as shown in the x-axis in Fig. 5.
- For the 292 mm pipeline diameter, it can be noticed that the flow rate of 3280 sm3/d will be achieved to transport the condensate from the manifold to the platform. This is true since the pressure is high enough to deliver the designed flow rate of 3280 sm3/d .This means that the 292 mm pipe size is suitable to transport the condensate.
- The 343 mm I.D pipe size is also suitable for the same reasons.

From the above discussion and as shown in table 2, the 241 mm will not be selected for the explained reasons. Now, two options are available either the 292 mm or 343 mm. Both diameters will fulfil the required pressure to transport the designed flow rate. However, the 292 mm is identified to be the suitable pipeline diameter to transport the designed flow rate of 32800 (sm3/d) because it is cheaper from economical point of view.

Comparing results from Fig. 7. It is clear that the 241 mm diameter failed the erosional velocity test as it is max erosional velocity higher than 1.On the other hand, both 292 mm and 343 mm passed the test as their values are less than 1.Table 3 was generated to compare the maximum velocity for both PIESIM values and calculated values. It can be noticed that both PIPESIM and the theoretically calculated values show similar results for the 4 flowrates .However, this indicates that theoretical calculations can be used to get very close values as those calculated by PIPESIN software. Since the 292 mm diameter passed the erosional test and is cheaper compared to the 343mm, all the following tasks will be conducted with 292 mm diameter.

5.2. Hydrate formation/insulation levels

Table 4. Final hydrate temperatures and hydrate pressures results (No insulation).

T (℃)	P (Bara)
5	9.75
10	17.75
15	36.75

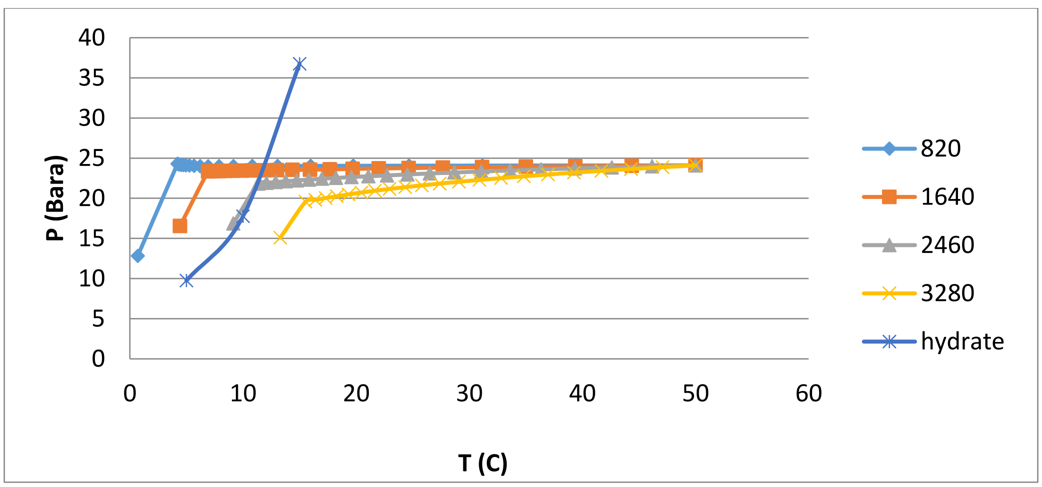

Fig.8. PT hydrate formation before insulating the 292mm which is the selected diameter.

Table 5. Final summery results for the insulation configurations task.

K1	Theoretical,t_{in}(m)	Theoretical U (w/M2.^{0}C)	PIPESIM, t_{in}(m)	PIPESIM U (w/M2.^{0}C)	Insulation material
0.02	0.0263	0.819	0.025	0.859	single layer Polyurethane

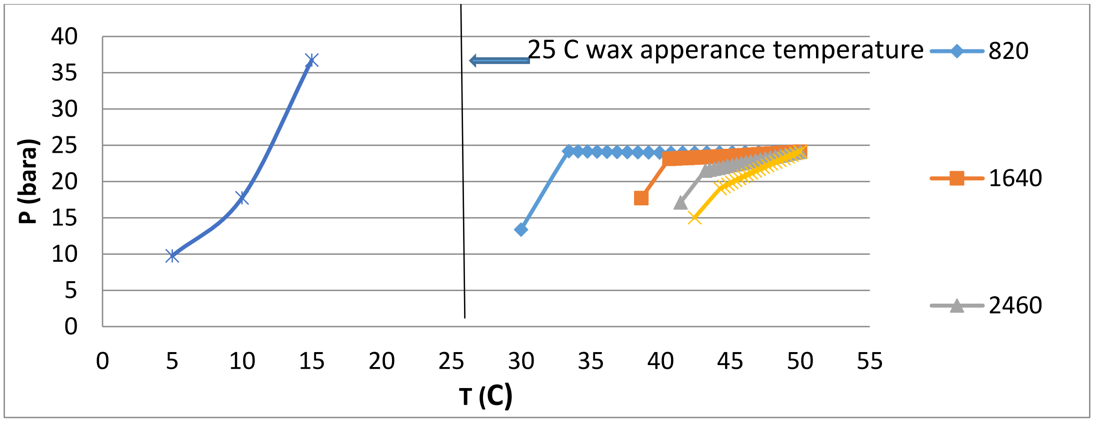

Fig.9. PT hydrate formation after insulating the 292mm pipeline diameter.

From table 4, pressures and temperatures were used to construct wax appearance line 25 ^{0}C below which hydrate will form. In the first scenario (no insulation) the risk of hydrate formation is clearly shown in Fig. 8. This is because hydrate tends to form at lower temperature < 25 ^{0}C and higher pressure. In order to prevent or manage hydrate formation, insulation level was established by calculating U values (Appendix C).Comparing U values in table 5, it was found that theoretical calculated U values is close but smaller than that obtained U value by PIESIM 0.819 (w/m^2.^{0}C) <0.859 (w/m^2.^{0}C) . Note it is advisable that a temperature of +5^{0}C should be taken as safety above the 25^{0}C.

In order to reduce the risk of formation and select OHTC, the thickness of insulation was calculated and compared with PIPESIM insulation thickness .The results present in table 5 show that the calculated insulation thickness of 0.026 m is very close to the PIPESIM insulation thickness of 0.025 m .This thickness of insulation is suitable since it gives good coating results to reduce hydrate as shown in fig. 9.The type of coating that would satisfy our obtained insulation thickness is suggested to be single layer Polyurethane Foam .

5.3. Terrain induced /server slugging

Table 6. Final summery of terrain and sever slugging results.

Q (m^3/day)	Lm(m)	Vm (m^3)	Calculated $\prod_{ss}$	PIPESIM $\prod_{ss}$
3280	123.142	8.120	0.191	0.199
820	113.869	7.622	0.202	0.243

From table 6,comparing sever slugging number from PIPESIM output data and the calculated sever slugging number in Appendix E, it is clear that slugging will appear since both PIPESIM and the SSB method calculated sever slugging number are less than 1.This indicates that slugging will occur in the pipeline and riser. The reasons leading to slugging are; the slight 15 m elevation drop over a long 5000 m pipeline preceding to the riser; and fluid might be flowing in "stratified" or "segregated" flow regime.

5.4. End of Field Life 90% Water cut

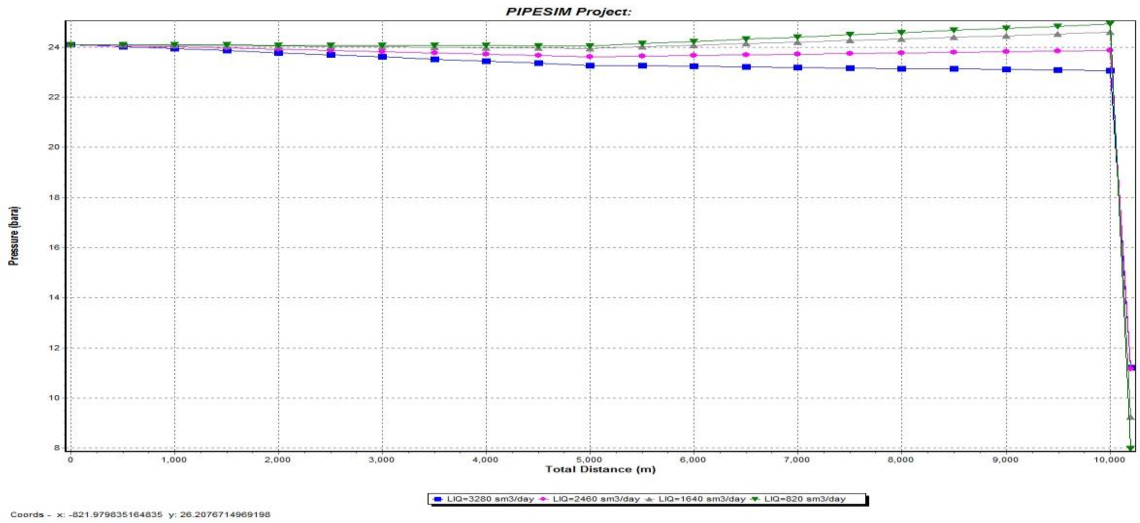

Fig.10. Pressure versus total distance at 90% watercut.

Due to the fact that water cut increases with decreasing field life, Fig. 10 was plotted to study pressure drop behaviour when 90% of water is produced at 4 flow rates 820 (sm3/d), 1640 (sm3/d), 2460 (sm3/d) and 3280(sm3/d).It can be noticed from Fig. 10 that both flow rates 820 (sm3/d) and 1640 (sm3/d) are below the minimum topside delivering pressure of 10.3 (bara).This will impact fluid flow for both flow rates at which fluid will not be delivered to the topside facilities. On the other hand, flow rates 2460 (sm3/d) and 3280(sm3/d) are both just above the minimum topside delivering pressure of 10.3(bara). Although, flow rate of 3280 (sm3/d) pressure drop is above the minimum, it is not good enough to deliver fluids without causing fluid flow problems such as increase liquid hold-up in the riser, which gives an increase hydrostatic pressure head. For the stated reasons, gas lift will be need at later filed life.

5.4. Operational Mode

Other operational mode that should be considered before finalising the pipeline design includes:

- Sudden changes in flow rate at start up operations which can cause fluid to surge at the receiving connection. This increase in flow rate make liquid to sweep from the pipeline.
- Turndown: is another operation mode that should be take care of .This because as fluid flow increases in the pipeline, temperature tends to decrease and if the temperature decrease to below 25^0C WAT point, wax and hydrate is likely to form.
- Start-up: it is believed that when a well is not producing (closed), fluids will be separate due to gravity in the pipeline. This will make gas to flow to the top of the pipeline and start to build up and when well resumes production, the gas goes from high pressure to low pressure system and cause what is called “Joule Thomson cooling”. Then, the cooling temperature may result in hydrate formation.
- Shutdown: temperature of fluid inside pipeline will decrease to the ambient temperature when a pipeline stops .This is again not desired as wax and hydrate may form.
- Blow-down: blow down is cause by reduction in the pressure and should be addressed as it contributes to hydrate formation.

6. Conclusion

Above case study can be summarized as follows:

- The 292 mm is identified to be the suitable pipeline diameter to transport the designed flow rate of 32800 (sm3/d) because it is more economical than the 343 mm.
- Hydrate formation will appear before insulation establishment.
- Hydrate formation is managed by coating the pipeline with a thickness insulation of 0.026 m.
- It is recommended to use +5^{0}C as safety above the 25^{0}C.
- Sever slugging number is less than 1.Therefore, slugging will appear in the riser
- Pressure drop for the 3280 (sm3/d) flow rate is above the minimum. However, gas lift will be need at later filed life.

Conflict of Interest

This is to certify that the author declares no competing interest.

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Appendix

Appendix A:
Pipe diameter selection

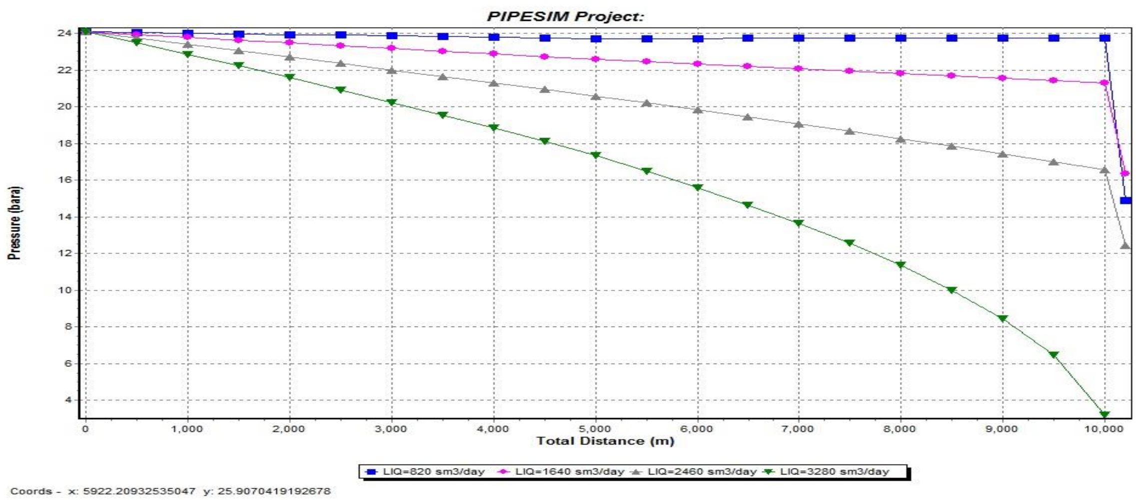

Fig. 11. Pressure versus total distance at different flow rates using the 241 mm diameter pipe.

Appendix B:
Erosion analysis calculations

Calculations involved in determining the maximum velocity (equation 1) that would satisfy erosion analysis according to API RP 14E are as follows:

Slip Liquid Holdup: $\lambda_L = 0.153$;
No-Slip gas Holdup: $\lambda_G = 1 - \lambda_L = 1 - 0.153 = 0.846$;
Liquid superficial velocity: $V_{SL} = 0.627$ m/s;
Gas superficial velocity: $V_{SG} = 3.470$ m/s
Liquid/gas mixture velocity: $V_M = V_{SL} + V_{SG} = 4.097$ m/s
Superficial velocities: (V_{SL} / V_M) = and (V_{SG} / V_M)
Density of Liquid, $\rho_L = 701.435$ Kg/m^3,
Density of Gas, $\rho_G = 11.73$ Kg/m^3
Now, No-Slip is: $\rho_m = \rho_L . V_{SL} + \rho_G V_{SG} = (0.153 \text{x} 701.435) + (0.847 \text{x} 11.73) = 117.44$ Kg/m^3
Inserting all obtained values in equation as follows:
$V_m^* = 1.22 * {}^{100}/_{\sqrt{117.44}}$ = 11.27 (ft/s).

Appendix C:

Hydrate formation & U value

Hydrate formation values used in plotting figure 8 (no insulation of the 292 mm diameter pipeline are represented in table x below.

Table 7. k -values obtained at different temperatures and pressures.

@1000kpa&5ºC		@950kpa&5ºC		@1800kpa&10ºC		@1750kpa&10ºC		@3600kpa&15ºC		@3750kpa&15ºC	
K1	Y/k1	K2	Y/K2	K1	Y/K1	K2	Y/K2	K1	Y/k1	K2	Y/K2
2.7	0.295	2.8	0.284	2.15	0.371	2.25	0.354	1.65	0.483	1.6	0.498
0.98	0.094	0.92	0.100	0.65	0.142	0.9	0.102	0.95	0.097	0.9	0.102
0.125	0.386	0.13	0.372	0.135	0.358	0.155	0.312	0.19	0.254	0.17	0.284
0.049	0.191	0.05	0.187	0.056	0.167	0.06	0.156	0.09	0.104	0.07	0.134
0.049	0.034	0.05	0.033	0.056	0.030	0.06	0.025	0.09	0.018	0.07	0.024
Total	1.002		0.978	Total	1.069		0.953	Total	0.958		1.043
		0.99				1.01135				1.001047	
	Hydrate (P)	975	Kpa		Hydrate (P)	1775	Kpa		Hydrate (P)	3675	Kpa
	Hydrate (T)	5	ºC		Hydrate (T)	10	ºC		Hydrate (T)	15	ºC

Table 8. Detailed calculations to determine U value

Gas mass flowrate (mg)	3.152 (kg/s)
Gas hold up	0.866
Liquid mass flowrate (ml)	29.078 (kg/s)
Liquid hold up	0.1339
Mixture of mass flowrate:(λL mL+λg mg)	6.624 (kg/s)
Mixture heat capacity	2204.49 (J/kg/k)
Outer diameter: 0.292+2*0.0127	0.317 (m)
Total length of pipeline	10200 (m)
HHeat transfer area, Aref=∏*D*L	∏*0.317*10200=10170m^2
T1,T2 and t1 respectively	50 ºC,30 ºC and 4 ºC
Using equation (3) $U = \frac{6.625}{10170} * 2204.496 \left[\ln\left(\frac{50-4}{30-4}\right)\right] = 0.819\ w/m2k$	

Appendix D:
Pipe insulation calculations

Table 9. Detailed calculation to determine pipe radius and thickness.

Conductivity of liquid, kL	0.173 W/m.k
Conductivity of gas, kg	0.06055 W/m.k
λL	0.1339
λg	1-0.1339=0.866
No-slip mixture conductivity km=(λL*kL+λg*kg)	0.07561 W/m.k
A, constant	0.027
Reynolds number coefficient	0.8
Prandtl number coefficient	0.33
Reynolds number	18844.7
Prandtl number	1.87
Inside pipe Reynolds number	1528918
Seawater,ρw	1000 kg/m3
Reynolds number coefficient,a	0.56
Conductivity of seawater (outside), Ksw	0.6055 w/mk
Prandtl number	4.14
	0.185011 m

- Dittus-Boelter equation $hi = A\left(\frac{KM}{D}\right)\left(\frac{DV\rho}{\mu}\right)^{a}\left(\frac{Cp\mu}{k}\right)^{b}$

  0.027(0.07561/0.292)(1528918)0.8(1.87)0.33= **762.09 W/m²k**
- Radius insulation:
  (1/0.919) =
  (0.159/0.146*762.099)+(0.1587ln(0.1587/0.146)/60.55+(0.1587ln(r1/0.1587)/0.02+0.1587/(0.158ha)
  = **0.185011m**
- Insulation thickness,tnis = 0.185-0.158 **= 0.027m**

Appendix E:

❖ Terrain induced & sever slugging

Terrain induced at 3280 sm^3/d and 820 sm^3/d

Table 10. Details need to calculate mean slug volume and mean slug length at 3280 (sm^3/d)

D (in)	Fluid Mean Velocity (m/sec)	Vm(ft/s)	Lm(m)	Ln(Lm)	Area (m^2)	Volume (m^3)
11.496	4.7339	15.5313	123.142	6.001	0.066	8.12

Using equation 4 mean slug length is calculated as follows:
Mean slug volume = 123.142*0.066 = **8.12 m³**
Ln(Lm) = -2.663+5.441[ln(11.496)]$^{0.5}$ +0.059[ln(8.242)] = **123.142 m**

Table 11. Details need to calculate mean slug volume and mean slug length at 820 (sm^3/d)

D (in)	Fluid Mean Velocity (m/sec)	Vm(ft/s)	Lm(m)	Ln(Lm)	Area (m^2)	Volume (m^3)
11.496	1.255	4.12	5.923	113.869	0.066	7.62

Using equation 4 mean slug length is calculated as follows:
Mean slug volume = 113.869*0.066 = **7.62 m^3**
Ln(Lm) = -2.663+5.441[ln(11.496)]$^{0.5}$ +0.059[ln(7.621)] = **113.869 m**

Sever slugging at 3280 m^3/d and 820 m^3/d

Table 12. Sever slugging calculations.

g(m^2/s)	A(m^2)	Oil density	Water density	Q_{oil}	Q_{water}	Q_{gas}	P ave	L flowline
9.81	0.066932	684.7567	0	0.042466	0	0.274611	1,720,000	10,000

After calculating (dp/dt) for both the flowline and riser using table x and output data. Sever slugging was found as follows:
$(dt/dt)_{riser}$ = 4261.96(kg/m/s^3) and $(dp/dt)_{flowline}$ = **814.81(kg/m/s^3)**

$$\prod ss = 814.81/4261.96 = \mathbf{0.191}$$

In the same way sever slugging was calculated for 820 (sm^3/d) flow rate.
$(dt/dt)_{riser}$ = 1070.09(kg/m/s^3) and $(dp/dt)_{flowline}$ = **216.73(kg/m/s^3)**

$$\prod ss = 216.73/1070.09 = \mathbf{0.2025}$$