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(Research Article)

Flow assurance analysis in Front End Engineering Design (FEED) of Subsea Flowline and Riser

Ipalibo Senibo George *, Charles U. Orji and Ibiba E. Douglas

Centre of Excellence in Marine and Offshore Engineering, Rivers State University, Port Harcourt, Nigeria.

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Abstract

Innovative subsea production systems (SPS) are required for deep-water oil and gas exploration in order to transport multiphase fluids—a complex mixture of water, gas, and oil—across long distances under challenging conditions. Significant technological challenges confront these systems, such as flow assurance, which ensures continuous fluid flow through pipelines, flowlines, and wells. Flow assurance issues can significantly impact production and incur costly downtime. This paper emphasizes the critical role of flow assurance analysis during the crucial Front-End Engineering Design (FEED) stage of SPS development. By utilizing industry-standard simulation tools like PIPESIM™, engineers can proactively identify and mitigate potential flow assurance problems that could hinder productivity. These analyses are crucial as FEED decisions significantly impact project cost-effectiveness. To illustrate the practical application of flow assurance principles, the paper presents a case study of a subsea architecture design for a specific manifold system. Considering operator requirements, flow assurance simulations were employed to guide critical decisions regarding material selection and optimal sizing of risers and flowlines. This demonstrates how flow assurance considerations during FEED directly influence cost-effective and optimized SPS design.

Keywords: Flow-Assurance; Subsea; FEED; PIPESIM; Multiphase

1. Introduction

The global decline of easily accessible oil reserves has driven the Exploration and Production (E&P) industry to set its sights on more remote and challenging environments. This shift necessitates the development of technologies to extract unconventional hydrocarbons like oil sands, heavy oil, and Arctic oil, alongside deepwater reserves according to Efthymiou [1]. However, these ventures present significant technological hurdles, particularly regarding safe and sustainable production in harsh conditions.

The subsea environment, arguably the most remote and uncharted on Earth, presents unique challenges for monitoring and intervention. Valbuena [10] opines that as oil and gas companies push into deeper waters, conventional subsea production systems struggle to maintain performance and operational integrity, jeopardizing project viability and exposing stakeholders to increased risk. This necessitates a paradigm shift, where reliability becomes a core principle from the outset - conceptualization, design, and execution - not just during operation. This is especially crucial considering the growing prevalence of electronic equipment in subsea applications. Any failure within these systems, and their associated instrumentation, can lead to significant production losses, environmental issues, and costly downtime.

Subsea production typically involves transporting multiphase fluids (a mixture of oil, gas, and water) over long distances to processing facilities.

* Corresponding author: Ipalibo Senibo George

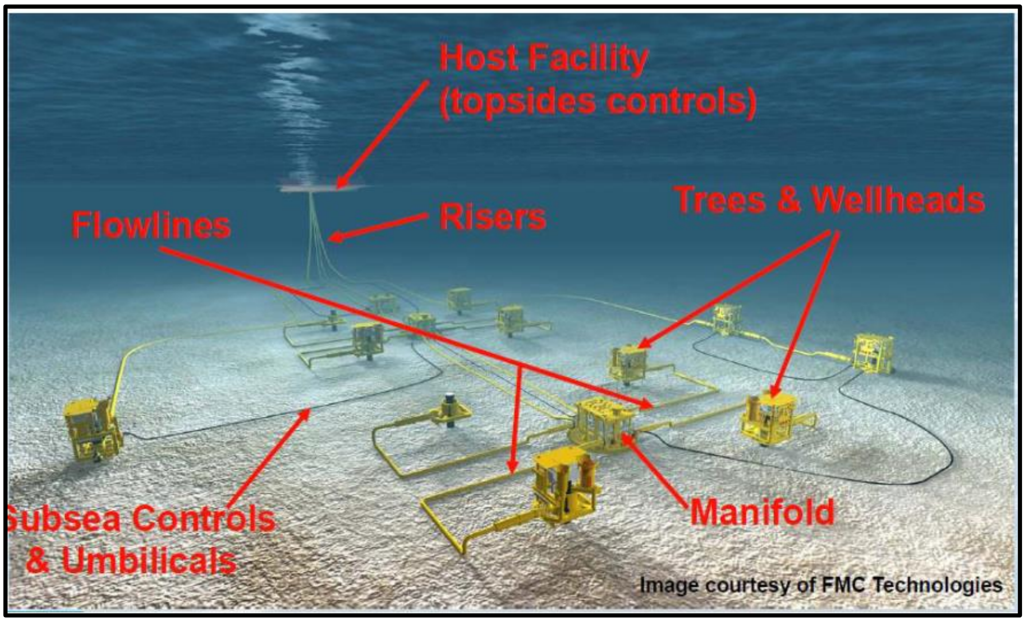

Figure 1 Typical Subsea Architecture

Hence, this demands effective flow management to ensure optimal productivity, especially considering the high costs associated with Front-End Engineering Design (FEED) and subsea infrastructure [11]. Beyond the challenges inherent in conventional production systems, subsea production faces additional hurdles related to multiphase flow. Rapidly changing pressure, temperature, and production profiles can lead to issues like wax build-up, scale formation, and hydrate formation within subsea pipelines [10, 12]. Flow assurance, a critical discipline for subsea engineers, studies these complex multiphase flow phenomena to develop solutions that guarantee efficient flow management [13]. As such, establishing a robust flow-management framework requires meticulous analysis, planning, and computational modelling (see Figure 1).

The transportation of natural gas from offshore wells to onshore processing plants presents a distinct set of challenges and unlike oil pipelines, gas pipelines are more susceptible to temperature and pressure variations, which can alter the physiochemical properties of the gas being transported according to Sloan [14]. This in our opinion, necessitates additional considerations for ensuring efficient and safe gas transportation. The complex environmental conditions encountered in deepwater environments, characterized by strong currents, waves, varying temperatures, and uneven seabed profiles (bathymetry), further complicate flow assurance considerations [10, 11]. Suffice it to say, that these factors, along with the operator's primary objective of achieving uninterrupted, cost-effective, and environmentally sound production, significantly influence subsea architecture and facility selection (see Figure 1).

Flow assurance encompasses a broad spectrum of disciplines within subsea production engineering [13]. It is primarily concerned with guaranteeing uninterrupted and efficient flow of hydrocarbons from the reservoir to the processing facility [2]. Several key aspects contribute to this overarching objective, including: hydrate management, wax management, scale management, slugging & flow regimes and erosion & corrosion. A review of literature reveals that a vast array of techniques and tools have been developed to address flow assurance challenges over the years and these include: chemical injection, thermal insulation, pipeline heating, pigging and material selection, to mention few [3, 4].

Therefore, flow assurance analysis and considerations are crucial during the conceptual design stage and FEED phase of subsea production systems (SPS) [5]. Proactive identification of potential threats to productivity and performance allows for the exploration of mitigation measures and solutions, ultimately avoiding costly downtime [6]. However, a key challenge lies in balancing capital expenditure (CAPEX) associated with implementing robust flow assurance solutions against operating expenditure (OPEX) or running costs [3, 7].

This research aims to demonstrate the effectiveness of industry-standard simulation tools in performing multidisciplinary engineering analyses during the FEED stage. The focus will be on predicting and mitigating potential flow assurance challenges in a long subsea tieback system located in the Gulf of Guinea, West Africa, operating under multiphase flow conditions.

2. Material and methods

2.1. Materials

In order to achieve the design analysis/considerations and performance evaluation to be done in this research work, the following are required:

2.1.1. Input data

Field data is essential to facilitate design of pipeline-riser system and to execute design and productivity analyses and according to Parthasarathy and Mai [15], it can be gotten from an assets SCADA system or Distributed Control System (DCS). The types of data required include; fluid properties data, production field development plan (FDP) for the deep offshore location, flowline and riser geometry, information about the flowline burial and met-ocean data to mention few.

Case Study

Field Development Plan (FDP) for a new gas condensate discovery is designed to operate four (4) producing wells gathered by a subsea manifold and subsequently flowing through a subsea tieback from manifold, up a riser, to an existing platform. The platform is to be equipped with facilities to separate oil and gas, with the oil pumped to shore and the gas compressed and transported. The fluid composition data is presented on table 1 below, with which the phase envelope is calculated for and plotted using multi-flash package in PIPESIM.

Table 1 Fluid Components for Gas Condensate

Component	Main Fluid (Mol%)	Injection Fluid (Mol%)
Methane	67.5	
Ethane	5	
Propane	2.5	
Isobutane	1	
Butane	1	
Isopentane	1	
Pentane	0.5	
Hexane	0.5	
Water	10	
Carbon Dioxide	2.5	
C7+ (Pet Fractions)	8.5	
Methanol		100
TOTAL	100	100

The Operator's desired production rate, as per design, is 14,000 STB/day for the base case but considerations are to be made for upward surging of the throughput up until a maximum allowable case of 16,000 STB/day (i.e., approximately 14%) – should the wells exceed design rate and a minimum allowable case of 8000 STB/day to be able to handle ***Turn-down Scenario***. For a fact, the ability to handle production exceeding the base design-rate of 14,000 STB/day (up to 16,000 STB/day) offers an opportunity to capitalize on higher well-productivity or favourable reservoir-conditions, as the case maybe, as it ultimately translates to increased revenue for the Operator. This is not however without its shortfalls, because facility design to handle such a wide range (14%) in production-rate, necessitates ensuring that all wellbore equipment, surface processing facilities, and transportation infrastructure are adequately sized and designed to accommodate this flexibility. Narahara et al. [16] in their optimization study on Agbami No.1 Discovery well in the Gulf of Guinea, suggest that reasonable care should be taken when performing a coupled reservoir-facility network model design, to avoid over-designing facility capabilities as it can lead to significant upfront capital expenditure (CAPEX)

From the design specification of the subsea production system (SPS), the arrival pressure at the platform must not drop below 400 psia. Also, the flowline and riser sizes available for selection have been presented on Table 2 below:

Table 2 Flowline and Riser sizes available for selection

Design Cases	Inner Diameter (in)	Wall thickness (in)	Corresponding Flow Rate (STB/day)
Minimum Size	7.981	0.322	8,000
Base Case	10.02	0.365	14,000
Maximum Size	12	0.375	16,000

It was specified that the flowline and riser sizes must be uniform for all scenarios (i.e., if 7.981" is selected for the flowline inner diameter, the riser must also have an ID of 7.981") and the ***erosional velocity limit*** must not be exceeded. However, this specification has failed to take into consideration the fact that flowlines typically experience higher pressure drops due to frictional losses compared to risers [3, 5]. Also, the erosional velocity limit adds another layer of complexity [3] and meeting this constraint at the design flow rate (14,000 STB/day) may force the selection of a larger diameter pipe than what would be strictly necessary for pressure management [17].

As part of the Flow Assurance (FA) consideration analysis, it is a requirement to determine the relationship between flowline/riser diameter and flow problems bearing in mind that the bigger the flowline and riser, the higher the cost [8, 9], so the objective would be to select the optimum diameter sizes that would satisfy the target throughput rate and specified boundaries.

2.1.2. Flowline and Riser Architecture/Geometry

PIPESIM model requires flowline-riser geometry as input, often based on real seabed profile (bathymetry). In this 9.656km case study, a horizontal flowline is modelled (Table 3) but seabed unevenness (bathymetry) is ignored, assuming a flat seabed.

Table 3 Flowline geometry and discretization

Horizontal distance (ft)	Measured distance (ft)	Depth Mean Sea Level (ft)
0	0	1600
1584	1584	1600
3168	3168	1600
4752	4752	1600
6336	6336	1600
7920	7920	1600
9504	9504	1600
11088	11088	1600
12672	12672	1600
14256	14256	1600
15840	15840	1600
17424	17424	1600
19008	19008	1600
20592	20592	1600
22176	22176	1600
23760	23760	1600

25344	25344	1600
26928	26928	1600
28512	28512	1600
30096	30096	1600
31680	31680	1600

Presented on table 4 below is information on the pipe and ground conductivity and the depth of burial of the flowline, as well as thermal information on the pipe insulation material. For the base case, the pipeline is not buried at all and the burial depth is 0 inches.

Table 4 Pipe insulation material details

Flowline Thermal Data		
Parameter	Value	Unit
Pipe Conductivity	45	W/m.K
Ground Conductivity	1.84937	W/m.K
Pipe Burial Depth	0	in
Pipe Coating Details		
Parameter	Value	Unit
Insulation Material Thermal Conductivity	0.2595	W/m.K
Overall Outside Diameter	11.25	in

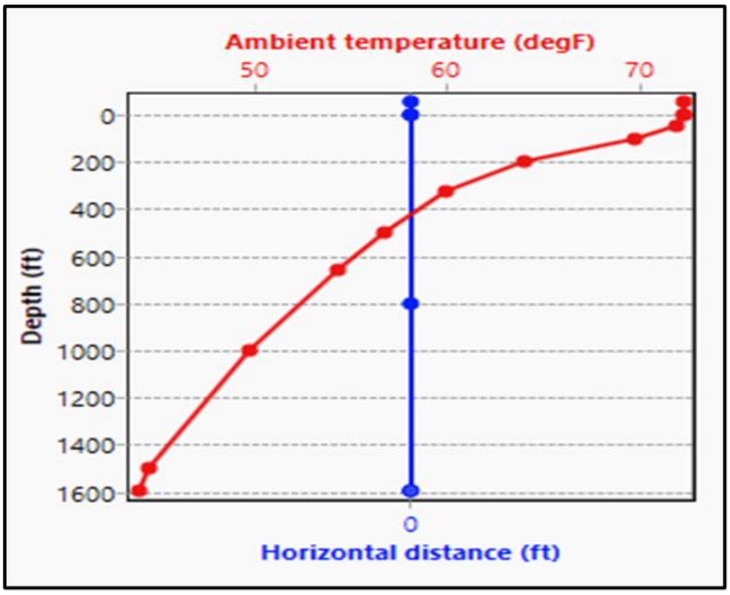

Figure 2 Riser Geometry and Ambient Temperature Profile

For the flexible riser, it stems from the riser-base (represented as a junction) up to the platform which is 60 ft above the MSL. Figure 2 is a graphical representation of the horizontal distance of 1600 ft from the sea bed and the temperature profile from sea bed to Air Surface for West Africa region (i.e., Gulf of Guinea).

All these parameters, were inputted into the software to design the base-case model for the initial simulation, to generate results to facilitate parametric/sensitivity analysis. The PIPESIM model from source (manifold) to sink (platform) is presented in Figure 3 below.

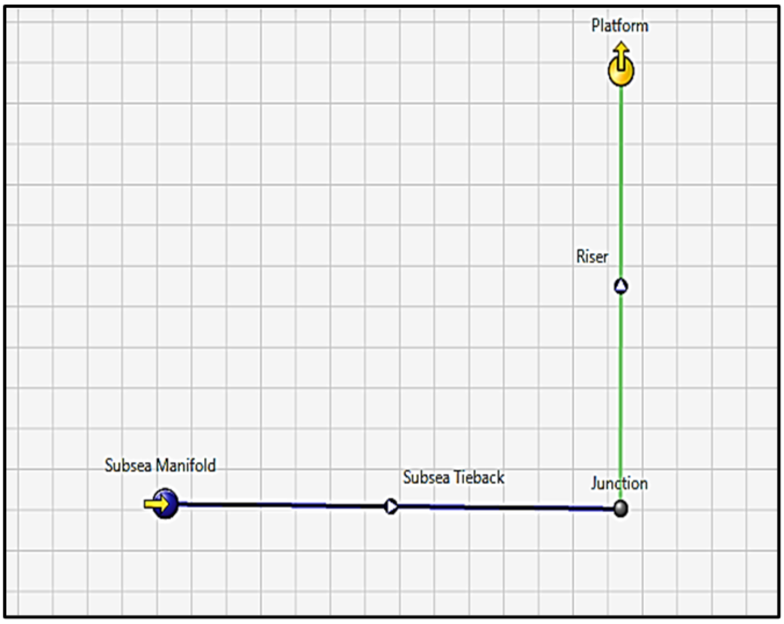

Figure 3 PIPESIM Model for Long Subsea Tieback

For flow assurance, PIPESIM™ steady-state multiphase flow simulator offers workflows and the simulator is frequently used to identify situations that require more detailed transient simulation than OLGA™ multiphase flow simulator. Such situations may include; shut-in, start-up, ramp-up, terrain-induced slugging, severe slugging, slug-tracking, hydrate kinetics and wellbore clean-up.

2.2. Method/Workflow

The initial riser design, created in the simulator using gathered data, serves as the baseline model. Two variations of this model are then simulated, reflecting the two mitigation techniques under investigation. Finally, the simulations are analysed to compare performance across all cases using relevant charts and graphs

2.2.1. Simulation Initialisation

To initiate simulations, PIPESIM requires initial pressure (P), temperature (T), and flow rate (Q) at the source (subsea manifold collecting from 4 wells in Field X). The program calculates unknown delivery parameters at the platform (sink) using a Pressure Traverse algorithm.

Table 5 Boundary Condition definition for Simulation Initialisation

Name	**Type**	**Pressure (P) (psia)**	**Flowrate type**	**Flowrate (Q)**	**Flowrate unit**	**Temperature (deg F)**
Subsea Manifold	Source	1500	Liquid	14000	STB/d	176
Platform	Sink		Liquid	N/A	STB/d	

The values of BC used to initialize the simulation is provided in table 5 above. Prior to production system sensitivity analyses, PVT calculations (including the plotting of a phase envelope) were ‘flashed’ by the aid of the Multi-flash package in PIPESIM.

2.2.2. PVT Calculations for Characterisation of the Reservoir Fluid

PVT properties are required for most reservoir, production, and surface processing calculations. Inaccurate estimation of PVT properties can lead to significant errors in calculation results [18]. Compositional PVT models track the surface production of hydrocarbon components. The partitioning of each hydrocarbon component between reservoir gas and oil phases is handled with the use of equilibrium constants (K values).

Equilibrium constants are functions of pressure, temperature, and composition. However, the most accurate source of K values is tuned EOS models – *which in this case is the **Peng Robinson (PR) model***. Nevertheless, we must take into account the fact that the tuning process for an EOS model requires careful experimental data selection and rigorous parameter adjustment to ensure accuracy for a specific system [18].

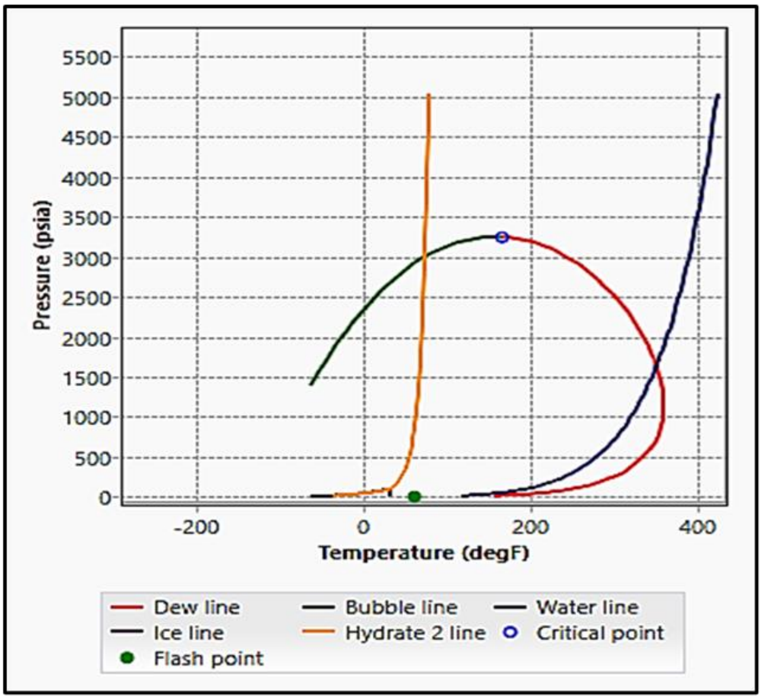

Figure 4 Phase Envelope showing PVT Behaviour

Using this EOS model, the PVT values were calculated for or flashed with which the PT plot in Figure 4 above was made showing the phase envelope. This provides information on dew line, water line and hydrate line to mention few

3. Results and Discussion

3.1. Subsea Tieback and Riser Size Selection

The first step in the design consideration is to determine the optimum diameter of the tieback and riser that satisfies the arrival pressure requirement of above or equal to 400 psia stipulated by the operator for minimum and maximum cases flowrates of 8,000 and 16,000 bpd.

To perform this evaluation a sensitivity analysis was carried out as displayed below:

3.1.1. Sensitivity Analysis on Flowline and Riser Sizes for Size Selection

From the sensitivity analysis plot in Figure 5 below, we observe that for the recommended available pipeline and riser sizes (i.e., 7.981, 10.02 and 12 in) as displayed on Table 2 above, the outlet pressures were determined for the various cases of production flow-rate.

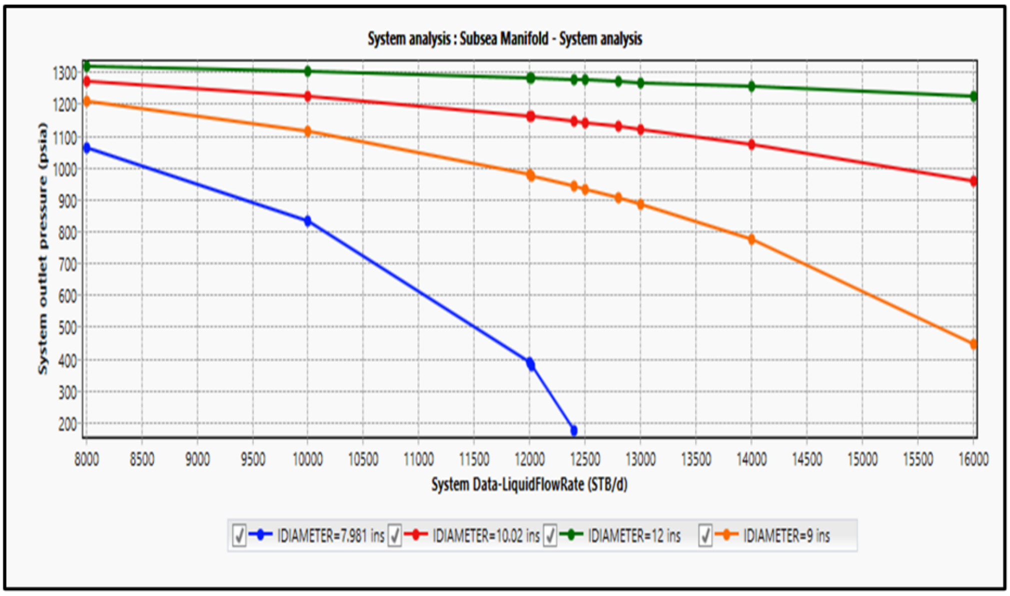

Figure 5 Sensitivity Analysis Plot for Size Selection

This plot shows that for 7.981" riser and pipeline, a system outlet pressure of about 1,080 psia is achievable for the worse/minimum-design case of 8,000 STB/day only and does not maintain the stipulated output pressure of 400 psia, defined by the operator, beyond a steady flow rate of 12,000 STB/day – which is well below the base case and maximum case scenarios of 14,000 STB/day and 16,000 STB/day respectively.

Similarly, the same system plot was generated for the 10.02 and 12" respectively as shown in Figure 5. These pipeline and riser sizes deliver outlet pressures at the platform over and beyond the stipulated 400 psia limit and as such, either of them can be suitable to be selected for the design from a technical standpoint but when we consider the economics, being that larger diameter pipelines/risers generally implies higher cost (i.e., CAPEX), the natural flowline/riser size selection would be the least of the duo and that is 10.02 inches.

3.1.2. Sensitivity Analysis on Maximum Erosional Velocity Ratio

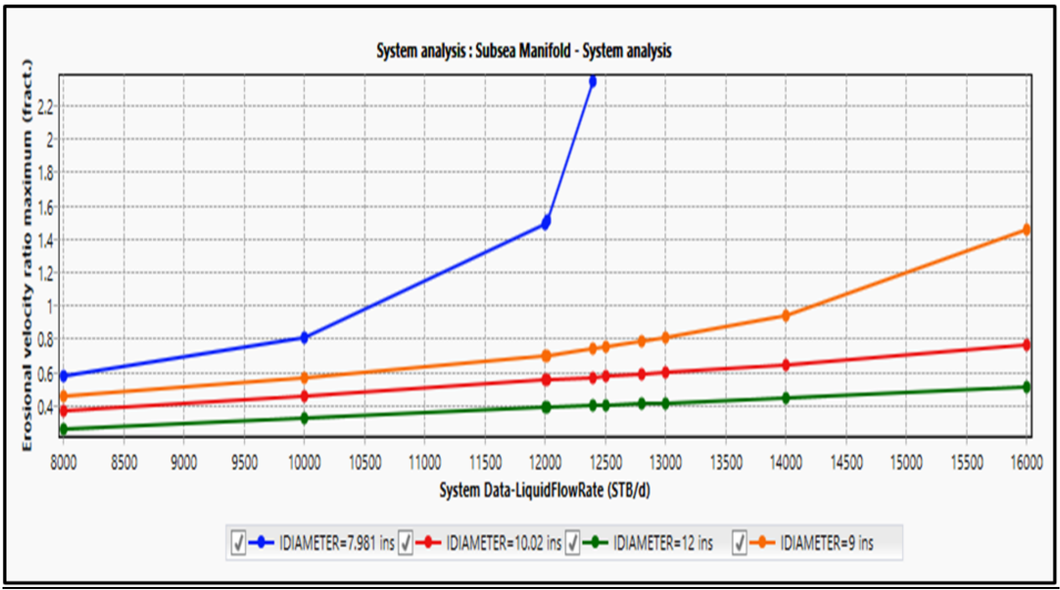

Figure 6 Maximum Erosional Velocity Ratio Sensitivity Plot

To further validate the size selection, a sensitivity analysis of the effect of flowline/riser ID on maximum erosional velocity ratio for the given design parameters is performed. From the plot on Figure 6 above, it can be observed that the minimum available ID size of 7.981" again performed poorly in contrast to the other sizes of 10.02" and 12" respectively.

Hence taking into consideration the cost for a larger diameter size selection and with this insight from the sensitivity analysis above, the flowline/riser size of 10.02” remained the most optimum selection from a techno-economic standpoint.

3.2. Predicting Hydrate Formation

Based on specification, the designed flowline has a roughness of 0.0018 inches and the thermal conductivity of the flowline material is 45 W/m.K – which is same for the Riser, though having a roughness of 0.00186 inches. The second phase of the analysis carried out in this research work, was to determine the possibility of hydrate formation for Gas condensate transport in the given long subsea tieback as part of FEED.

Hydrate forming molecules most commonly include methane, ethane, propane, carbon dioxide, and hydrogen-sulfide and from Table 1, we see that C1 – C3 are present in the fluid composition in substantial percentages and this gives the first insight into the likelihood of hydrate formation. Hydrates are sometimes formed downstream of a choke where fluid temperature can drop into the hydrate formation region due to the popular ***Joule-Thompson*** effect but since there is no choke in the design this is not a concern in this analysis.

3.2.1. Pressure-Temperature Profile Plot Analysis

For predicting the likelihood of hydrate formation, the worst-case scenario of 8,000 STB/day which is the turndown rate for the design is applied. By the aid of the simulator PIPESIM™, the flow assurance calculations related to hydrate analysis were done. For implementation of this design in the Gulf of Guinea, West Africa, it can be observed in Figure 7 annotated below that at $0^{o}F$ for the sub-cooling delta temperature, the long subsea tieback would enter the hydrate formation region at an approximate distance of 14,256 ft.

The corresponding pressure at this point, as can be seen on Figure 8 is approximately 1460 psia. The hydrate formation temperature increases with increasing pressure; therefore, the hydrate risk is greatest at higher pressures and lower temperatures.

Hence, we can deduce that at some point in the life of this project, the Operators would stand the risk of hydrate formation which would reduce production output, ultimately translating to financial implications associated with turn-around maintenance and other mitigative measures for hydrates (such as injection of chemical inhibitors) that increase the running cost or operating expenditure (i.e., OPEX).

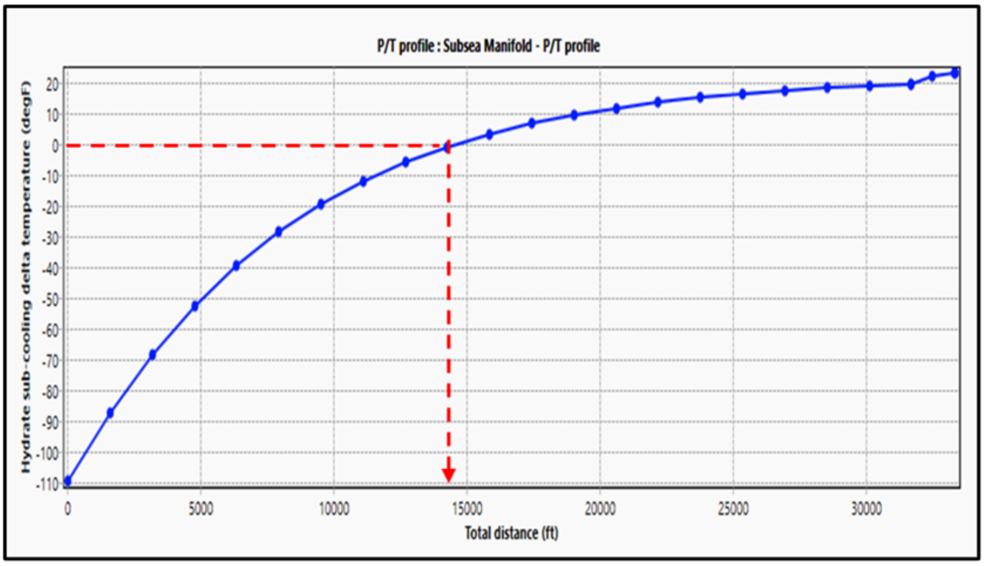

Figure 7 Predicting point of Hydrate formation on Long Subsea Tieback

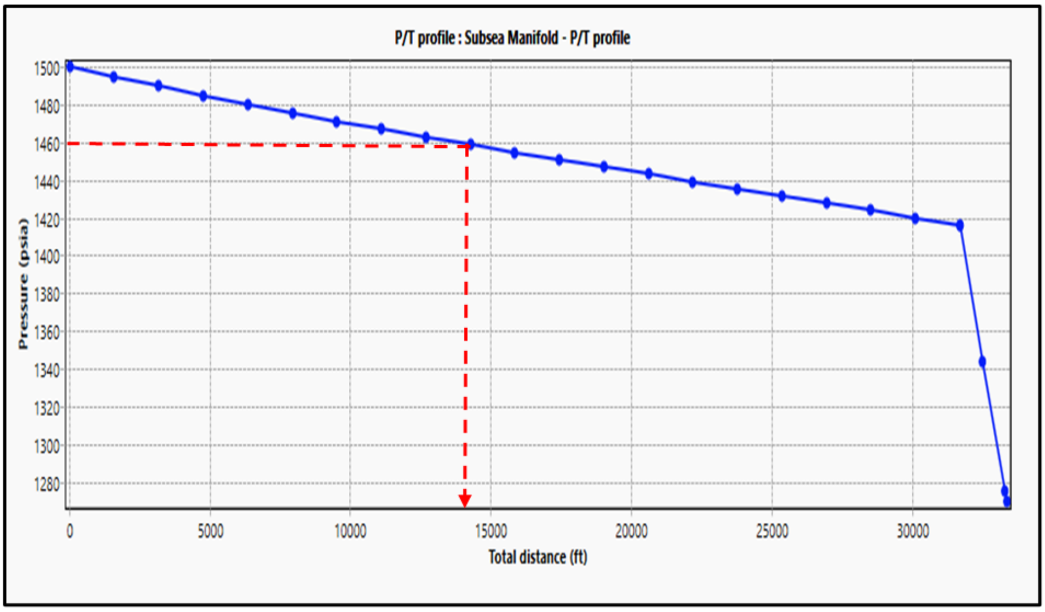

Figure 8 Predicting Hydrate formation Pressure

3.2.2. Phase Envelope Determination of Hydrate Formation

The phase envelope for the Gas Condensate being transported (i.e., Composition Fluid – CFluid) was regenerated and displayed on Figure 9, similar to Figure 4 above. But unlike the latter, a new line (PT profile) has been introduced into the envelope as a result of the preceding calculations and analysis done in 3.2.1.

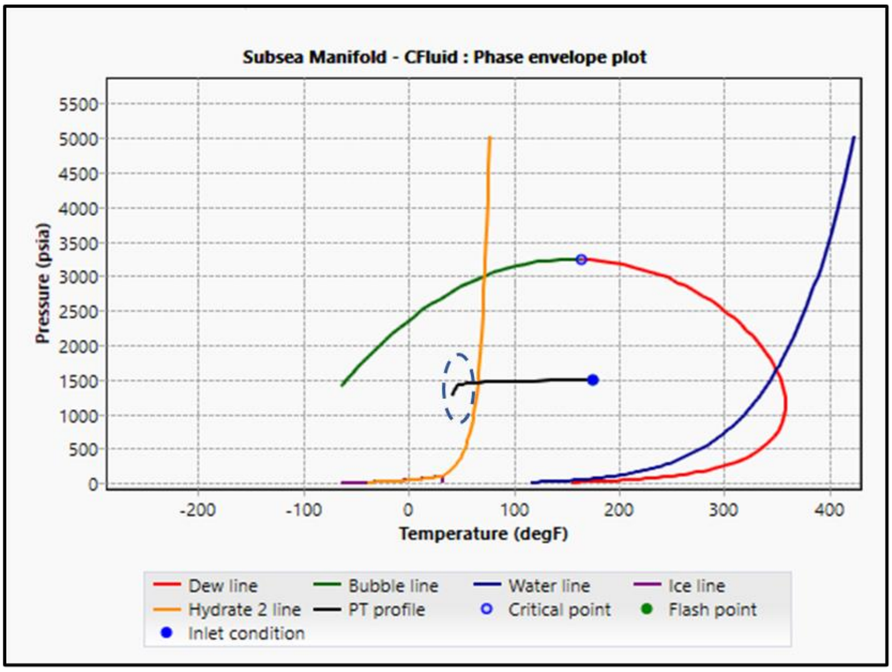

Figure 9 Validating Hydrate Formation Prediction with Modified Phase Envelope

This P/T profile line intersects the hydrate formation line as can be observed in Figure 9 above. The portion of the calculated P/T line circled out, indicates the portion of the system in the hydrate formation region. This further validates our deduction that for the turndown rate design scenario, representing a phase in the reservoir life when reservoir pressure declines alongside flowrate, there is a high risk of hydrates forming.

Going by this observation, we can further deduce that the pipe insulation coating thickness of 0.25” specified, is not optimal for all possible cases of the subsea systems reservoir and production operating conditions, as it affects the flowline and riser components. As such, to mitigate for this there is need to determine an optimum pipe coating thickness.

3.3. Investigating Slugging Behaviour

Severe slugging is a transient phenomenon in risers that can occur in a multiphase transport system consisting of a long subsea tieback followed by a riser [19]. PIPESIM simulator can predict to some degree the possibility of slug formation. It calculates an indicator number ratio between the pressure build-up rates of the gas phase and that of the liquid phase in a flowline followed by a vertical riser and makes a profile plot of this indication number for the various scenarios.

Table 6 Sensitivity of Severe Slugging Indicator for given flow rates

Severe Slugging Indicator	
Liquid Flow Rate (STB/day)	Indicator Number
8000	1.223
14000	1.493
16000	1.586

The values of indicator number give insight as to how likely the occurrence of slugging behaviour is in the system. Severe slugging is expected when the Severe Slugging Indicator number is equal to, or less than, 1. Table 6 shows the results of the calculations done using PIPESIM and we can observe that slugging occurrence is not really a concern within design limits of this field development plan – as none of the indication numbers were less-than/equal-to one.

The closest in our case study is the turndown rate of 8,000 STB/day which has an indication number of 1.223. This model can be used to determine the onset of severe slugging, but the model cannot predict how long the slugs will be and how fast slugs will be produced.

4. Conclusion

In this study, we have highlighted the critical role of flow assurance in deepwater oil and gas production, particularly for long subsea tiebacks transporting multiphase fluids. The high costs associated with Front-End Engineering Design (FEED) and subsea infrastructure necessitate efficient production to ensure project viability. Analysing potential challenges early in the design phase allows engineers to make informed decisions that optimize production efficiency, minimize CAPEX and OPEX, and ensure environmentally responsible operations.

A deep-dive reveals that flow-assurance addresses the challenges arising from rapidly changing operating conditions that can lead to wax build-up, scale formation, and hydrate formation within subsea pipelines and by studying these multiphase-flow phenomena, flow assurance engineers develop solutions to guarantee uninterrupted and environmentally sound hydrocarbon production – a key objective for any operator. This research demonstrated the effectiveness of industry-standard simulators like PIPESIM™ in performing multidisciplinary flow assurance analyses during FEED. The case study applied this approach to a subsea tieback system in the Gulf of Guinea, predicting potential flow assurance problems under multiphase-flow conditions. Furthermore, the study showcased the importance of flow assurance in material selection and optimal sizing of flowlines and risers during FEED.

The current design offers opportunities for further optimization such as: quantifying methanol injection for hydrate control and incorporating a fit-for-purpose slug catcher (considering riser angle and potential slugging. Again, while traditional methods like methanol injection are effective, future research should focus on more environmentally friendly solutions. Advancements in deepwater insulation materials and integrating flow assurance with digitalization for real-time monitoring and predictive maintenance hold promise for efficiency gains and cost reductions [7].

As the industry pushes boundaries, continuous advancements in flow assurance will be paramount for safe, sustainable, and economically viable production in deepwater environments.

Compliance with ethical standards

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Disclosure of Conflict of interest

No conflict of interest to be disclosed.

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