

Investigating Slug Flow Characteristics of a Pipeline-Riser System Using Olga Simulation Tool

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Abstract

Slug flow is a predominant flow regime in offshore oil and gas production. This work investigated the slugging phenomenon in a pipeline-riser system. The pipeline has a nominal diameter of 0.3714m and spans a horizontal distance of 7.7km laid on an uneven seabed with a 200m riser. The OLGA 2015 simulation tool was used to develop the model, as well as carry out transient simulation. The liquid holdup, pressure, fluid temperature and water volume fraction were discussed. Hydrodynamic and severe slugging was found to occur along the pipeline and at the riser-base respectively. The pressure and temperature plots showed cyclic pattern; consequently, the system would be susceptible to fatigue, thermal stresses and thermal stress corrosion cracking. Information obtained from the liquid holdup and water volume fraction plots reveal that there was a very high potential for water overflow at the separator. This was noted to impact negatively on efficient offshore oil and gas production, and on integrity of offshore assets.

Keywords: Slug flow, offshore, oil and gas production, fatigue

1. INTRODUCTION

It is an indisputable fact that Oil and Gas Industry remains the main stake of the global energy production. Oil and gas account for over 33% and 10% of global energy consumption respectively. Despite wide clamour, huge interest and rapid development of non-fossil fuel and renewable energy, it is predicted that they will remain the dominant energy source in several years to come.

Oil and Gas exploitation and production involves the lifting and transportation of hydrocarbons from the reservoir, via the wellbore and piping systems, to the topside or other end facilities. A typical well-pipeline riser system of a typical offshore oil and gas production system is shown in Fig. 1. This system consists of three inter-connected subsystems; namely; the production well system, the subsea pipeline system and the vertical riser system. The separation process of gas/oil water is done on the topside. A choke valve is placed before the separator at the topside to regulate the flow from the well.

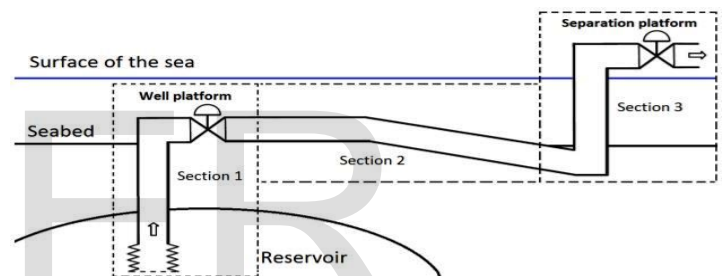


Fig. 1: A typical well-pipeline-riser system [5]

As subsea processing remains comparatively unexploited; multiphase fluids of most offshore production systems are not separated on the seabed, but on the topside platform. Transportation of multiphase flow poses a lot of flow assurance challenges, such as: wax deposition [1], hydrate formation [2], solid particle erosion [3], asphaltenes [4], slug formation [5], etc.

Slug flow is one of the most predominant flow regimes in multiphase flow; other flow regimes include stratified flow, wavy flow, annular flow, dispersed bubble flow and bubble flow. Slugging is an irregular multiphase flow characterized by a series of liquid plugs separated by a relatively large gas pockets; these liquids plugs whose length may vary from several meters to, sometimes, three or four times the riser length in severe cases [6]. Slug flow can be observed in many two-phase flow engineering applications; such as: flow in oil and gas pipelines [5] and other process industries [7]. The formation of the slug regime is transient in nature, passing from stratified to wavy flow, and then onto slug flow [8].

Slugging in oil and gas production poses a serious flow assurance concern for engineers and designers. The two main areas on which slug flow can cause difficulties to field operators are in the operability of the gas and liquid processing plant and in

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the mechanical integrity of the pipework upstream of the plant [9]. In most cases, the separator overflows, and liquid ends up in gas outlet, causing severe damage of processing facilities. Similarly, slugging can also cause disturbance to gas handling facilities, with compressors being forced in and out of cycle; while at bends, there will be changes in reaction forces as slug enters and leaves the bend. Pipeline slugging is very turbulent; the turbulence will tend to scrape off any corrosion protection in the pipeline, as well as, the protective scale; ensuring that the pipe is always exposed to the corrosive environment [10]. Hence, the integrity and reliability of the piping systems and end facilities are severely affected by slugging.

In some cases, a very high upstream pressure is required to push the slug through the system. Such high upstream pressure can reduce the flow rate of the well. In terrain-induced slugging, the liquid slug completely blocks the flow in the system. During this period, there is no production at all, until the pressure builds up to push out the liquid slug [5]. This results to a major instability in the system.

The problem of slugging is not new in the industry; several efforts have been made to mitigate/eliminate its occurrence. However, slug prediction and simulation still poses a serious challenge to the industry. More studies are ongoing for better understanding of the phase transition associated with slugging; as well as, more robust models are being developed for liquid holdup in liquid slug and elongated bubble. However, this work focuses on the application of OLGA Simulation tool to model, simulate and predict slug occurrence in a generic pipeline-riser system.

1.1 SLUG MODELING AND PREDICTION

Slug flow and its associated problems have long being explored since 1970s. Several researches and experiments have been carried out to investigate its occurrence, prediction and elimination strategies in oil and gas production.

The Unit Cell concept was first extensively explored by Duckler and Hubbard [11]. They establish fundamental equations describing slug velocity from considering a mass balance over the film region and the slug. This concept, which is the most accepted approach, tends to reduce the intermittency to periodicity and assume fully-developed flow so that the complex structure can be simplified to an equivalent unit cell, consisting of a liquid slug and a long bubble [12]. Several advance studies based on this concept have been developed ([13], [14]). Particularly, Nicholson et al. noted equations for the prediction of slug translational velocity were insufficient; hence, a new concept, drift velocity, was defined to model their results [14]. Obvious drawbacks and limitations of this model include: loss of symmetry in vertical flow; influence of flow regimes, annular to stratified regime of the film; limitations on gas fraction and bubble motion prediction modelling. Schmidt et al. pre-

sented a simple hydrodynamic computer model [15]. This model simulates a complete severe-slugging cycle in a flow-line/riser system where the flowline is modelled by a gas buffer, with only a short flowline to the riser. However, the model fails to account for the influence of two-phase flow in the upstream pipeline; hence, limiting its applicability. Small scale tests were conducted for the prediction of severe slugging in offshore lines, and evaluation of the possibility of its reduction/elimination [6]. The results obtained revealed that liquid viscosity had no effect on the occurrence of severe slugging, but an increase in viscosity reduces the slug-arrival velocity; Riser-base supplementary gas lift reduces severe-slugging severity; however, unrealistically large amounts of extra gas are required for the complete removal of severe-slugging features. However, this work was carried out with limited range of liquid viscosities; if a broad range is experimented, results may reveal effects of liquid viscosities on severe slug occurrence. While working on British Petroleum (BP) Exploration, Hill and Wood developed a modified model for predicting slug frequency, slug length and maximum possible slug length prediction [9]. Based on extensive data obtained from Wytch Farm and Prudhoe Bay field, they developed a modified equation for the Slug frequency. The results showed better correlation when compared to the existing model. Another significant contribution to slug flow modelling was made by Taitel and Barnea [16]. Assuming a uniform film thickness and a simplified momentum balance equation, they carried out the calculation of pressure gradients in steady state slug flow in inclined pipes using liquid hold up. A steady-state two-fluid model was developed by De Henau and Raithby [17]. Strong correlations for air-water and air-oil slug flow in horizontal pipes were obtained over a limited range of experimental data. Meanwhile, Orell [18] advanced the works of Taitel and Barnea [16] to calculate pressure drop, taking into consideration the application of Reynolds number in friction factor calculation.

Further studies were carried out in Bagci and Al-shareef [19] to illustrate the slug flow in horizontal and inclined pipes. They developed a mathematical model and a computer program which was based on the sink/source concept at the pipeline connections. The effects of changes in film characteristics, superficial liquid velocity, inclination angle, pipeline diameters, and superficial gas velocity on slug flow characteristics were also investigated. Throneberry et.al [20] investigated the solid particle erosion phenomenon on slug flow. Conducting experiment using "Boom loop" and electrical resistance (ER) probes, they developed a mechanistic model for predicting erosion rates, which was consistent over the range of experimental testing. Ansari and Shokri [21] developed a numerical model of slug flow initiation in horizontal channels using a two-fluid model. Applying the governing equations of the two-fluid model, hyperbolic analysis of the two-fluid "Pres-

sure Free Model," and closure models, a numerical solution method that solved transient two-fluid equations using a class of high-resolution shock capturing methods was developed based on TVD Lax-Freidrichs (High order) method. A simplified dynamical model for severe slugging in pipeline-riser systems was developed by Jahanshahi and Skogestad [22]. They compared their results, together with other previous models such as: 'Storkaus model' [23], 'Di-Meglio model' [24], 'Kaasa model' [25], and 'Nydal model' [26] with the results from the OLGA Simulator. The result obtained showed the proposed model was able to maintain the main dynamics of the severe slugging flow regime. A methodology for calculation of a slug, two-phase flow hold-up in a horizontal pipe has been presented [8]. The proposed model was both tested extensively against experimentally collected data and verified with data for slug flow in horizontal pipes obtained from other sources. The developed model gave excellent results with less than 7% error, and was proven to be more accurate when compared to existing models. Kjølås et al. [18] simulated the hydrodynamic slug flow using the LedaFlow slug capturing model. The LedaFlow 1D model employed a three-fluid nine-field modelling approach to simulate the thermodynamics and hydrodynamics of the gas-oil-water flow in pipeline systems. The two-phase experiments which were conducted in 2003 at the Large Scale Loop at SINTEF Laboratory were analysed and compared with the LedaFlow model. The results obtained showed a good agreement between the LedaFlow Slug Capturing model and the experimental data (for GLR=10). Losi et al. [28] conducted a study on modelling and statistical analysis of high viscosity oil/air slug flow characteristics in a small diameter horizontal pipe. The study adopted a statistical approach which generated probability density functions for slug lengths. A new correlation was used to model their dependency on superficial gas velocity. The pressure drop obtained from the model showed good agreement with experimental data, providing information about the mechanics of the flow regime.

1.2 OLGA TRANSIENT SIMULATION TOOL

OLGA software is a dynamic multiphase simulator widely used in the Oil and Gas industry for transient simulation [29]. Coined as a short form for "Oil and Gas simulator, the modeling tool makes it possible to simulate fluid flow, ensuring improved efficiency and optimization of offshore oil and gas production. OLGA is used for modeling and simulation of networks of wells, pipelines, risers and process equipment, covering the production system from bottom hole to the processing facilities.

OLGA is applied for engineering throughout field life from conceptual studies to support of operations. It is predominantly used both in the engineering and design phase, as well as in operation phase of any offshore project. During design and

engineering stage, OLGA is very useful for mapping of operational limits and to establish standard operational procedures, with emphasis on optimizing the production window during field life. OLGA is also used for safety analysis and risk assessment of equipment malfunctions and operational failures. During operation, OLGA is used to establish operational procedures and limitations, emergency response and contingency plans. OLGA is also a very useful tool for training operators on current best practices in the industry.

During operation phase, several events where OLGA simulation is extensively used can be summarized below;

- Pipeline start-up and shut-down
- Pipeline blow-down
- Change in production rates (Turn-up slugging analysis)
- Design of Process equipment (Compressor, Pump, Separator, Choke etc.)
- Pipeline pigging (Pigging Slug Analysis)
- Hydrate control
- Wax deposition
- Tuning (Sensitivity and post-optimal analysis)
- Wells: Flow stability, Artificial lift, WAG injection, Well Testing, Well control
- Safety and Risk Analysis
- Training of operators.
- Front End Engineering and Design

OLGA 2015.1 is the latest version in a continuous development which was started by the Institute for Energy Research (IFE) in 1980. The oil industry started using OLGA in 1984 when Statoil had supported its development for three years. Data from the large scale flow loop at SINTEF, and later from the medium scale loop at IFE, were essential for the development of the multiphase flow correlations and also for the validation of OLGA. Since then, oil and gas companies have supported its development, and provided relevant field data to help manage uncertainty, predominantly within the OLGA Verification and Improvement Project (OVIP).

2. METHODOLOGY

The OLGA 2015.1 simulation tool was used in this work. The uniqueness of this version when compared with the other version is the introduction of a new slugtracking model "OLGA2015". OLGA2015 implements a stochastic slug initiation methodology which simulated the irregular behavior of slugging over time; thus, characterizing the slug initiation better. Previous versions used "OLGA6" slugtracking model. The HydrSlug-pvt module was adopted; this was due to limitation of available information and computation constraints. The module models hydrodynamic slugging using PVT Lookup table. The lookup table file is based on a PVT analysis and computation of thermodynamic properties of a fluid with con-

stant total composition. A table file is normally generated by using a fluid property package with a specialized OLGA table file generator. A PVT Lookup table file contains tables for varying pressure and temperature for basic fluid properties for gas and liquid, and optionally water as a separate phase. When applying the PVT Lookup tables, OLGA reads the table files and interpolates in the property tables to obtain fluid and related phase properties for specific pressures and temperatures at every segment along a pipeline. The system configuration is shown in Fig. 2. This consists of an inlet (closed node), an outlet (pressure node), a branch (pipeline-riser system) and a valve (hydrodynamic choke valve).

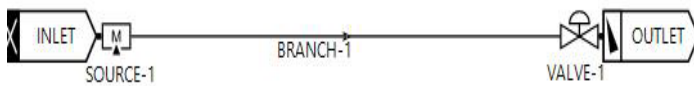


Fig. 2: The system configuration

The pipeline under study has an approximate horizontal length of 7700m and a riser length of 200m. The seabed bathymetry is uneven, enabling formation of hydrodynamic slugging; and steep undulating at riser-base, enabling terrain-induced slugging. The OLGA simulation tools models the

pipeline (BRANCH-1) as a number of pipes stretching between two points in space, divide into a number of segments (Control volume). The pipeline profile is shown in Fig. 3; while the detailed geometry and properties are given in Table 1. A summary of the options used in the modeling are stated in Table 2.

The simulation was carried out for two hours; wax deposition and heat loss from the pipe is negligible. The pipe is solid and rigid, with negligible elastic deformation. The fluid flowing in the pipeline is multiphase, with three phases – oil, water and gas; sand and other solid particles are assumed to be negligible. The flow model used is OLGA HD stratified flow model, which gives a 3-dimensional flow description at 1-dimensional speed. As earlier stated, the PVT fluid file was used as input data for fluid properties; hence compositional tracking was not carried out. This reduces the computational space and time required in the modeling. "1STORDER" mass equation scheme was used; this is more rigorous, and gives more accurate solution when compared to the alternative "2NDORDER" mass equation scheme. The fluid inlet temperature is 72.3°C while the pressure regulated by the valve at the outlet is 683 bar atm.

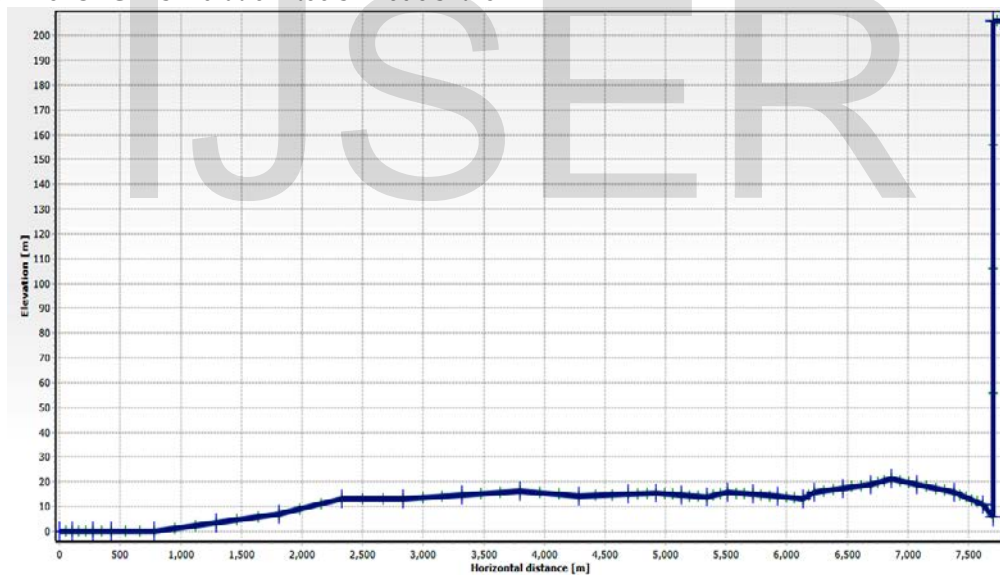


Fig. 3: The pipeline-riser system profile

Table 1: Branch-1 Pipeline system geometry and configuration

| Pipe no. | Label | Diameter (m) | Roughness (m) | Length (m) | Elevation (m) |
|----------|---------|--------------|---------------|------------|---------------|
| 1 – 1 | INLET | 0.362 | 3E-05 | 100 | 0 |
| 1 – 2 | INLET_B | 0.362 | 3E-05 | 173 | 0 |
| 1 – 3 | PIPE_1 | 0.371 | 3E-05 | 151 | 0 |
| 1 – 4 | PIPE_2 | 0.371 | 3E-05 | 355.217 | -0.001 |
| 1 – 5 | PIPE_3 | 0.371 | 3E-05 | 514.012 | 3.507 |

| | | | | | |
|--------|---------|-------|-------|---------|--------|
| 1 – 6 | PIPE_4 | 0.371 | 3E-05 | 514.012 | 3.508 |
| 1 – 7 | PIPE_5 | 0.371 | 3E-05 | 521.536 | 6.165 |
| 1 – 8 | PIPE_6 | 0.371 | 3E-05 | 506.22 | 0 |
| 1 – 9 | PIPE_7 | 0.371 | 3E-05 | 481.443 | 1.626 |
| 1 – 10 | PIPE_8 | 0.371 | 3E-05 | 481.453 | 1.625 |
| 1 – 11 | PIPE_9 | 0.371 | 3E-05 | 486.504 | -1.932 |
| 1 – 12 | PIPE_10 | 0.371 | 3E-05 | 408.1 | 0.473 |
| 1 – 13 | PIPE_11 | 0.371 | 3E-05 | 230.301 | 0.658 |
| 1 – 14 | PIPE_12 | 0.371 | 3E-05 | 207.402 | -0.903 |
| 1 – 15 | PIPE_13 | 0.371 | 3E-05 | 207.402 | -0.903 |
| 1 – 16 | PIPE_14 | 0.371 | 3E-05 | 174.513 | 2.14 |
| 1 – 17 | PIPE_15 | 0.371 | 3E-05 | 207.302 | -0.902 |
| 1 – 18 | PIPE_16 | 0.371 | 3E-05 | 207.302 | -0.902 |
| 1 – 19 | PIPE_17 | 0.371 | 3E-05 | 207.402 | -0.902 |
| 1 – 20 | PIPE_18 | 0.371 | 3E-05 | 95.033 | 2.518 |
| 1 – 21 | PIPE_19 | 0.371 | 3E-05 | 231.006 | 1.67 |
| 1 – 22 | PIPE_20 | 0.371 | 3E-05 | 231.006 | 1.67 |
| 1 – 23 | PIPE_21 | 0.371 | 3E-05 | 174.513 | 2.14 |
| 1 – 24 | PIPE_22 | 0.371 | 3E-05 | 209.014 | -2.4 |
| 1 – 25 | PIPE_23 | 0.371 | 3E-05 | 308.6 | -3 |
| 1 – 26 | PIPE_24 | 0.371 | 3E-05 | 235.4 | -5 |
| 1 – 27 | PIPE_25 | 0.362 | 3E-05 | 82.8 | -5 |
| 1 – 28 | RISER | 0.362 | 3E-05 | 200 | 200 |
| 1 – 29 | TO-SEP | 0.362 | 3E-05 | 70 | 0 |

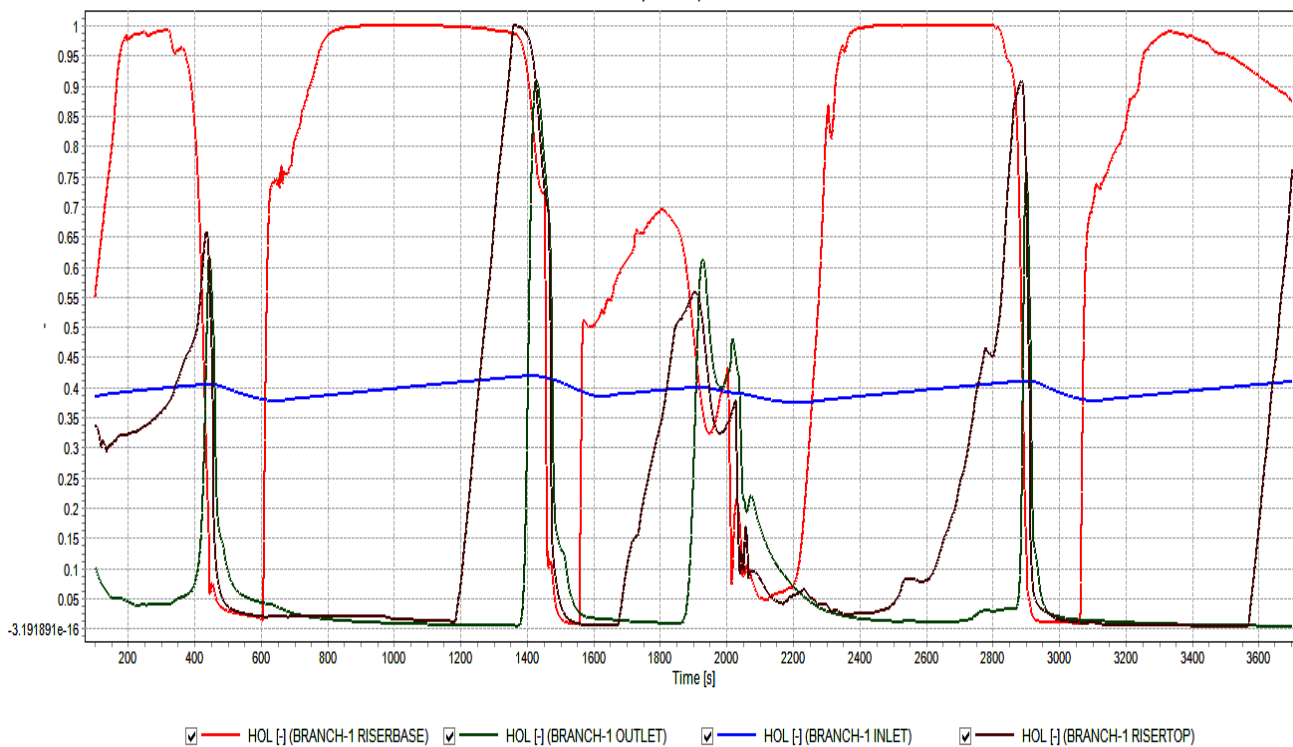


Fig. 4: A plot of Liquid Holdup variation with simulated time

Table 2: Modeling Options applied in the simulation

| | Flow model | OLGAHD |
|---------------------|----------------------|----------------------|
| Overall setting | Mass eq scheme | 1STORDER |
| | Compositional model | OFF |
| | Debug | OFF |
| | Drilling | OFF |
| | Phase | THREE |
| | Elastic walls | OFF |
| | Void in slug | SINTEF |
| | Steady state | ON |
| | User defined plug-in | OFF |
| | Temp. calc. | ADIABATIC |
| | Wax deposition | OFF |
| | Restart | OFF |
| | Integration | Simulation starttime |
| Simulation stoptime | | 2 h |
| Minimum time step | | 0.01 s |
| Maximum time step | | 1 |

It is important to note that there are four major sections of interest in the model; they include: Inlet, Riser-base, Riser-top and Outlet.

3. RESULTS AND DISCUSSIONS

As earlier stated, the model simulation time is two (02) hours. However, for clarity, the various plots presented in this section show results for 64 min. These results are given below:

3.1 Liquid holdup

Fig. 4 shows the plot of the liquid holdup with time. The liquid holdup at the inlet (depicted with a blue curve) has a fairly constant value of 0.4. This shows that the well composition is 40% liquid and 60% gas. As expected, the liquid holdup base builds up at the riser for an average period of 200s attaining a peak value of 1 when the riser-base is completely blocked by the liquid; meanwhile, there is steady decline in liquid volume is at the outlet. The produced gas builds up behind the liquid slug for period of 360s; until it is sufficient to push the liquid slug up through the riser. During this period, production is cut off because of the accumulation of slugs at riser-base. As the gas pressure sufficiently pushes the liquid accumulated at the riser-base, the liquid holdup at the riser-top increases, attaining its peak value of 0.66 at 440s.

The second slug profile at the riser-base builds-up at about 800s of the simulation period. The liquid fraction at the top of the riser increases, attaining a peak value of 1. The liquid holdup at the outlet is fairly regulated by the choke valve, with high spikes within intervals. Such spikes cause serious problems in the separator. The separator would experience liquid

overflow which would impact negatively on other processing and gas handling equipments. It is important note that cyclic nature of this occurrence can create fatigue stress on the pipeline, riser and the separator.

3.2 Pressure and Temperature

The plot of the pressure variation with time is shown in Fig. 5. The outlet pressure is regulated at 68.3 bar atm. by the choke valve located between the riser-top and the outlet. The pressure at the inlet and the riser-base builds up as severe slugs accumulate at the riser base, attaining maximum values of 87.5 bar and 84 bar, respectively. The sharp decrease in pressure occurs when the gas pushes the liquid slugs up through the

riser; the cycle is repeated over again after every 817s. The pressure at the inlet is higher than the pressure at the riser-base throughout the simulation period, with a maximum differential value of 18.5 bar occurring at about 1510s of simulation time. This is attributed to the pressure drop that occurs as the fluid flow through the 7.7km pipeline. The pressure at the riser-top also shows a recurring pattern, with a critical value of 72.5 bar. The recurring pattern of the pressure at the inlet, riser-base and outlet poses serious threat to integrity of the pipeline, especially at tees and elbow locations [6].

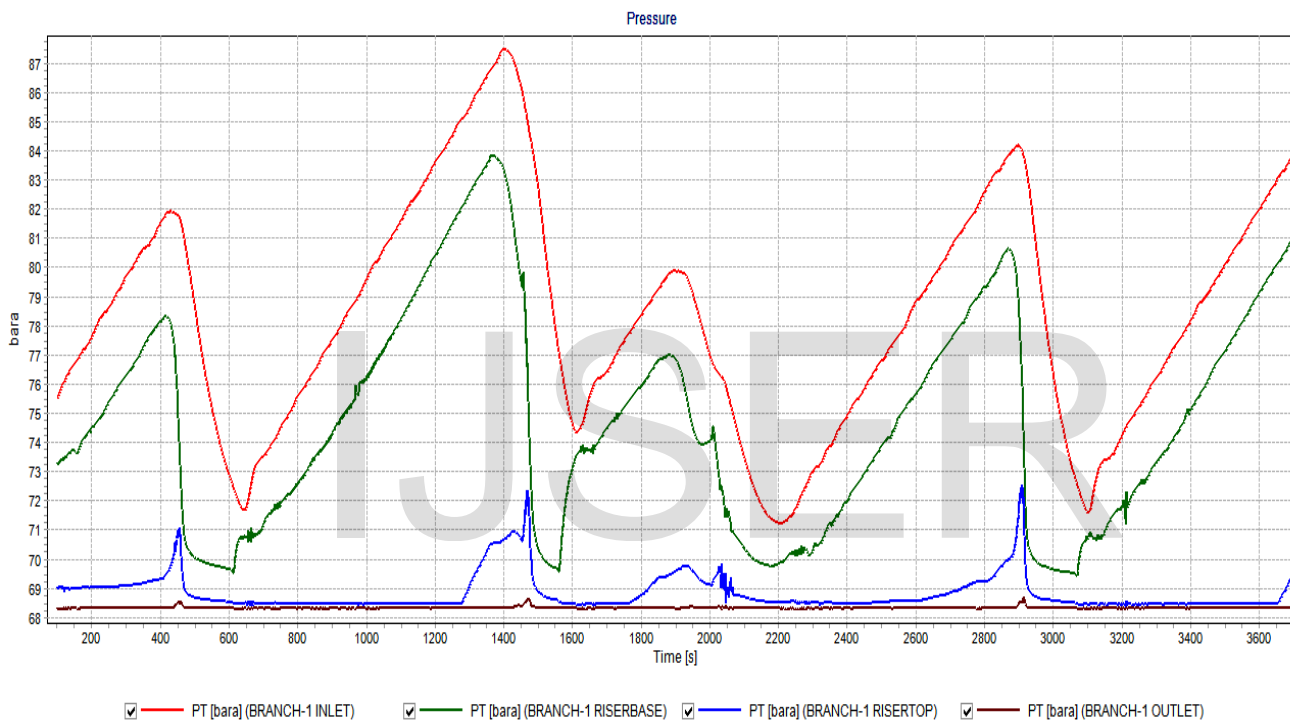


Fig. 5: A Plot of Pressure variation with simulated time

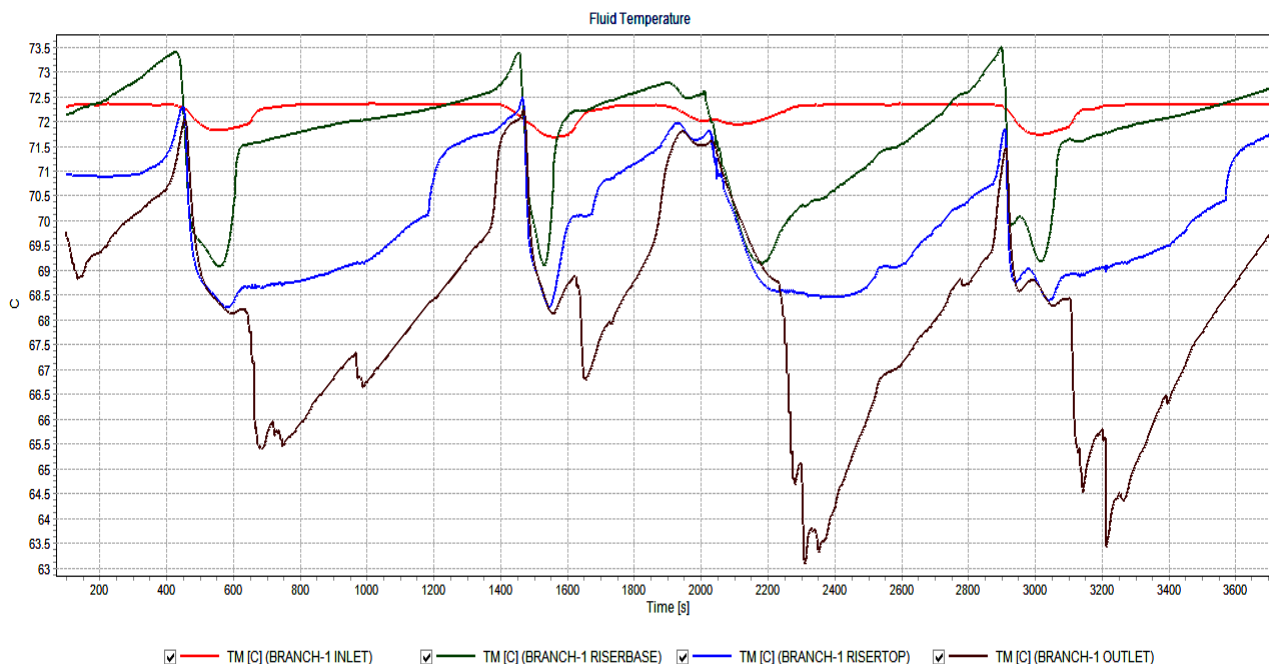


Fig. 6: A plot of Fluid Temperature variation with simulated time

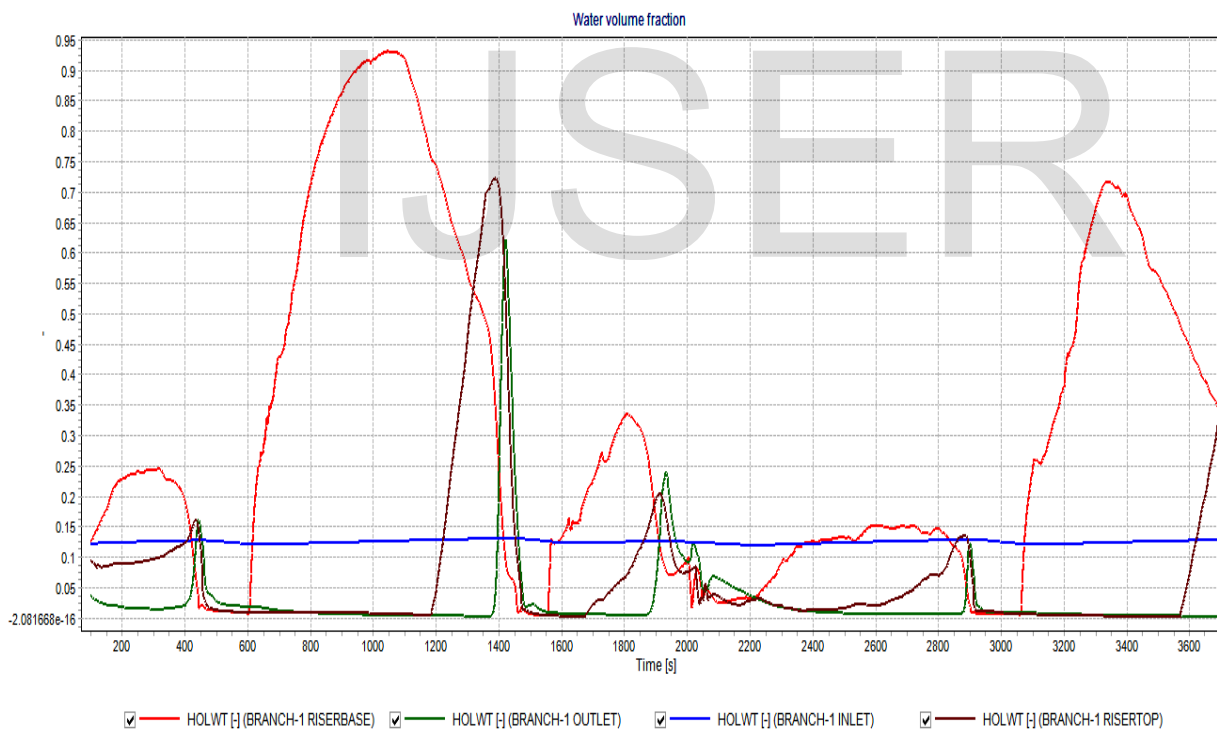


Fig. 7: A plot of Water volume fraction with time

From Fig. 6, the fluid temperature at the inlet is fairly constant at 72.3 °C, as specified during the modeling. The temperature at the riser-base, riser-top and outlet increases steadily during the slug accumulation phase, but decreases sharply as the liquid slug is pushed up by the accumulated gas. It is important to note that the process is assumed adiabatic; hence, there is no heat loss to the pipewall. In real-life, the temperatures

would be lower than those presented here. Thermal stresses created by irregular nature of the temperature pose serious design challenges, as potentials for creep and thermal-induced corrosion in the pipeline is very high.

The minimum temperature obtained is about 63°C; this is above the pour-point for wax formation, as well as asphaltenes

and hydrate formation temperature. It is important to note that adiabatic condition was assumed. This means that there is no temperature loss to the environment. This is not obtainable in practice, considerable drop in temperature as flowing fluids continuously lose heat to the cold seabed environment. Such temperature drop can lead to formation of hydrates, wax and asphaltene deposits. These occurrences will have a multiplier effect on the severity of slugging.

3.3 Water Volume fraction

The water volume fraction for the simulated flow is shown in Fig. 7. Typical of several green field found in the Gulf of Guinea, the multiphase flow through the inlet has a volume fraction of 0.135. It is important to note that the water fraction in the riser-base (illustrated by the red curve) rises to a critical value of 0.93 within 18 min of production flow. This is as a result of severe slugging at the riser-base. Water, having the highest density, accumulates at the base of the riser. The accumulation of gas behind the slug pushes the water-slug up the riser, as can be seen in the increasing water volume fraction at riser-top after 20 min and consequently, increasing water volume fraction at the outlet after 23 min. With a peak water volume fraction of 0.62 at the outlet, there is very high tendency of water overflow at the separator. Its grave consequences on production and flow assurance cannot be over-emphasized.

4. CONCLUSIONS

This work has successfully investigated the slug characteristics of a generic pipeline-riser using OLGA 2015 simulation tool. The conclusions made from this study include:

- a) The liquid holdup curve reveals that severe slugging would occur at the riser-base, completely blocking the riser-base for a mean period of 460 s; this will cause major instabilities in the system
- b) From the liquid holdup and water volume fraction plots, a maximum liquid volume fraction of 0.9 and water volume fraction of 0.63 occurs at the outlet at about 1410 s. This indicates a high possibility of liquid overflow at the separator.
- c) The cyclic behavior of the pressure and temperature makes the system vulnerable to fatigue stresses, thermal stresses, and thermal stress corrosion cracking on the pipeline, riser and processing facilities.

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