Investigating Methods of Attenuating Severe Slug Formation in Deepwater Production Risers

ABSTRACT

Severe slugging involves large magnitude fluctuations in pressure and flow rate in the riser due to low gas flow rates and low Gas-liquid ratio (GLR). This work evaluates two mitigation concepts: topside choking and riser base gas lift to determine which technique is more desirable.

A base case model was created to understand the nature of slugging with an input mass flowrate of 15kg/s, separator operating at 22.5Bar and 37^{0}C. After 8hours of simulation, presence of a severe slug was observed at the production riser. Two models were created from the base case to mitigate the severe slugging. An introduction of topside choke to eliminate or reduce the riser slugging, likewise deployment of Riser base gas lift (RBGL) to achieve the same purpose.

The result indicated that with the introduction of topside choke and reducing the opening percentages of the choke from 80% to 5% stepwise, the slugging amplitudes were greatly reduced from 3.3bar to 0.3bar. Though this led to back pressure and reduction in production. A 50% choke opening was suggested as the optimal choke opening for the simulated case. Results from the introduction of dehydrated gas with a mass flow rate of 1.2kg/s at the riser base indicated slug elimination from the riser and flowline. The results of this simulation were observed at the end of the riser (inlet to the separator) after about 8hours 20mins

This report identifies that of the two simulated techniques (topside choking and RBGL), RBGL is more efficient in addressing slug issues without impacting field production.

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Keywords: Topside Choking, RBGL, Severe Slugging, Gas-lift, Mitigation, Riser, Deepwater

1. INTRODUCTION

Many oil-producing countries have turned to deep offshore drilling. Since 1995, Deepwater offshore oil output has increased dramatically, with an average annual value of 20 million barrels of oil equivalent [1]. Riser slugging is a flow regime that occurs in multiphase pipeline-riser systems and is characterized by significant flow and pressure oscillations. The irregular flow caused by riser slugging can cause significant operational issues for downstream receiving facilities, necessitating an efficient and effective method of removing or mitigating riser slugging.

Recently, anti-slug control systems that stabilize the flow in the pipeline under the same operating conditions that would result in riser slugging have emerged as the preferred solution for avoiding riser slugging. The formation of slug arises from the flow regimes commonly found with the liquid and gaseous phases of hydrocarbons when in transit, and it is a major flow assurance issue in multiphase flow [2].

One of the ways of eliminating fluctuation because of slugging is by choking. In practice, oil and gas industry have used this method for many years to eliminate severe slugging by manipulating the valve opening at the exit of the riser, which unfortunately could negatively affect production [3]. Controller has been used, and it has been reported to be able to help remove this problem by stabilizing the system at larger valve opening [4]. Significant efforts have been concentrated on modeling and understanding the slug attenuation mechanism for choking up until the last few years [5], the preferred solution to avoid or reduce the problems associated with riser slugging has been to design the system such that the slugging potential is minimized or to change the boundary condition (that is, reducing the topside choke valve opening) to remove the slug flow from the system [6].

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None of these solutions is optimal. Design changes often involve installation of expensive equipment such as slug catchers and reducing the topside choke valve opening introduces extra pressure drop that will limit production when the reservoir pressure goes down as the reservoir is depleted. Schmidt *et al* (1979) first proposed an alternative approach based on feedback control to avoid riser slugging. The key concept in that paper was to avoid riser slugging by automatically adjusting the topside choke valve position based on an algorithm with a pressure measurement upstream of the riser and a flow measurement in the riser as inputs [7].

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Hedne and Linga (1990) used a more conventional PI (Proportional-Integral) controller based on an upstream pressure measurement to avoid riser slugging [8]. Both these papers are based on experimental work in medium scale flow loops and show the potential for using control solutions to avoid riser slugging in pipeline-riser's systems. The benefits of using a control solution are that no expensive equipment is needed and that no significant pressure drop is added to the system. However, the work of Schmidt *et al*. (1979), Hedne and Linga (1990) did not result in any reported industrial applications.

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In the last ten years or so, there has been a renewed interest in control-based solutions to avoid riser slugging. Courbot (1996) presents a control system to prevent riser slugging implemented on the Dunbar pipeline. The approach in this paper was to implement a control system that uses the topside choke valve to keep the pressure at the riser base at or above the peak pressure in the riser slug cycle, thus preventing liquid accumulation in the bottom of the riser [9]. This approach effectively removed riser slugging in the system, but it did so by automating the old choking strategy rather than affecting the stability of the flow regimes in the pipeline. This means that an extra pressure drop was introduced in the system due to the high set point for the pressure controller. Henriot *et al*. (1999) presents a simulation study for the same pipeline as Courbot (1996), where the set point for the riser base pressure is set considerably lower. In this work, the controller is probably stabilizing an unstable operating point rather than just keeping the process away from the riser slugging region, although this is not shown explicitly [9,10].

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Self-lift approach in severe slug mitigation, the self-lift approach was invented and developed as a method to eliminate severe slug in multiphase flow subsea lines [11]. Barbuto (1995) described this novel approach as the use of an auxiliary line that connects the downwards inclined flowline with the main riser [11]. A schematic detailing the configurations of the connection points is as shown in Figure 1, with Point A – the connection point between the auxiliary line and the vertical line (main riser); Point B – the connection point between the production line and the auxiliary line; and Point C – the connection point between the production line and the vertical line. This design mitigates severe slug by conveying the gas of the multiphase flow from point B to point A; this is possible due to the differences in pressure at point B and A. [11]. The gas bubbles conveyed into the vertical line help break up the liquid slugs [4]. Moreover, the quantities of gas contained in oilfields were either

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greater or lesser compared to the oil [12]. That meant that although the gas cap of a reservoir was not noticeable, the oil still contained a considerable amount of dissolved gas.

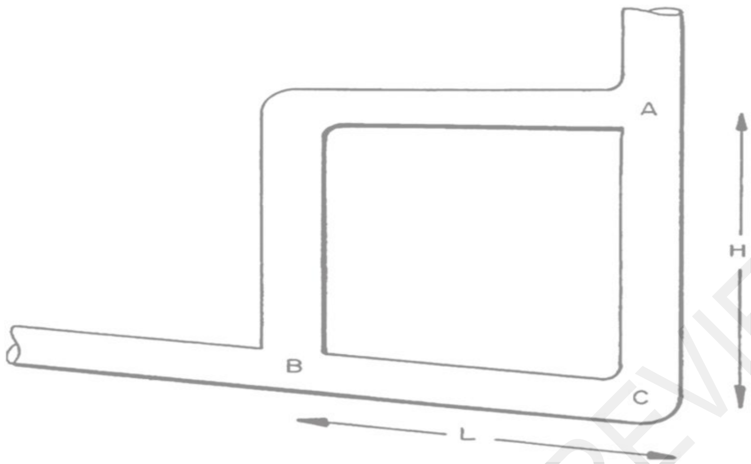

Figure 1: Schematic diagram of self-lift approach [11]

Tengesdal (2002) used this novel approach to model the mitigation of severe slug at the riser base. The approach was not considered to need any additional gas injection from the platform and was therefore termed ‘self-gas lifting’ [13]. This approach appeared to be quite beneficial as any extra-cost needed to compress external gas for mitigation of severe slugs, to transport the gas, and to store it on platforms topside, could all be reduced or completely waived. The following conclusions were deducted from the research that: The approach caused a reduction of hydrostatic head within the riser and of the pressure in the production line. From experimental observations, it is ideal to have the injection point at the same level or slightly higher than the take-off point for optimum performance. From the experiments, it was observed that a small choking was needed to stabilize the flow when the injection point is at a higher level than the take-off point. This approach to mitigating severe slug was not sensitive to changes with liquid and gas flowrates [13].

Hollenberg *et al*., (1995) presented an approach that was different for removing severe slugging from a pipeline-riser system. By introducing a small separator on top of the riser, the gas and liquid flow can be controlled separately above a certain frequency. This structure, called the S3 R Slug Suppression System also allows for accurate measurement of the gas and liquid rate, and by controlling the total mixture flow rate and the pressure in the small separator, the system can be stabilized [14]. Kovalev *et al*., (2004) report that the S3 system has been successfully implemented at the North Cormorant and Brent Charlie platforms in the North Sea [15].

The use of riser topside pressure measurement as a variable for severe slugging control has been reported with diverging views. The controllability analysis reported by (Storkaas 2002) showed that the riser top pressure alone is not a good variable for riser-pipeline instability control [17]. This is since the zeros of the corresponding transfer function are in the right half- plane (RHP) of the complex plane.

Dynamic choke is a choke manipulated by active control based on real time changes of system variables. The choking position is not fixed but adjusted based on a measured variable for achieving stability. Riser base pressure, riser top pressure and flow rate are commonly adopted control variables. Dynamic choking is therefore preferred as an efficient option to controlling slugging problems in riser-pipeline systems. Storkaas and Skogestad applied a systematic analysis of the riser-pipeline system using control theories. The analysis also included the assessment of the stability characteristics of the system using the riser top valve opening as the manipulated variable. Based on their analysis, they identified the riser base pressure as the best variable for stabilizing riser-pipeline system [16,17]

Jones *et al*., (2014) stated that the most effective mitigation approach to slugging is riser top valve choking (topside choking) [18]. Jansen *et al*., (1994) agreed with Schmidt *et al*., (1979) that choking eliminates severe slug by increasing the back pressure and acting as a flow resistance proportionally to the velocity of the liquid slug in the riser [5,7]. This meant that choking could potentially balance and maintain the multiphase flow with 'minimal back pressure'. However, Ogazi *et al*., (2011) argued that an inherent disadvantage with this approach is the extra back pressure induced on the pipeline and recommended the use of an active feedback control (dynamic choke) that could attenuate the slug flow and increase production [4]. Tengesdal (2002) used this novel approach to model the mitigation of severe slug at the riser base. The approach was not considered to need any additional gas injection from the platform and was therefore termed 'self-gas lifting' [13]. This approach appeared to be quite beneficial as any extra-cost needed to compress external gas for mitigation of severe slugs, to transport the gas, and to store it on platforms topside, could all be reduced or completely waived.

Havre *et al* (2000), report the first industrial implementation of an anti-slug controller. Which presents an anti-slug control system for the Hod-Valhall pipeline and illustrates its performance with both simulations and actual field data. The simulation results illustrate an interesting fact; by turning the control system off and keeping the same valve opening as was implemented (on average) by the control system, the riser slugging returns in the system. This proves that the control system stabilizes an unstable operating point. This unstable operating point, where the flow in the pipeline is steady, exists at the same boundary condition as would normally result in riser slugging. Havre and Dalsmo (2001) gives a more detailed treatment of the control system introduced in Havre *et al*. (2000) [19,20].

The most popular slug flow mitigation techniques are not always optimal, and it is necessary to develop an optimal solution for site specific deep offshore production projects. And this is what this research aims to achieve through simulating different techniques using same field data to be able to determine the optimal solution for slug flow for a given West Africa field through comprehensive analysis.

Majority of the techniques for attenuating slug formation in risers are developed from numerical simulations in simulators such as the Schlumberger OLGA and others and in most cases have not been deployed in a field situation. As such, selecting a field case study that allows for trying the various techniques can be an arduous task as some field cases are not effective for deployment of some already existing techniques.

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2. MATERIAL AND METHODS

For the purpose of the investigations to be done, two mitigation techniques have been selected for performance evaluation, in order to identify the most efficient technique for the location. They are:

i. Topside Choking,

ii. Riser Base Gas lifting

2.1 Material

The primary materials utilized for the performance evaluation to be done in this work are:

2.1.1 Software

The industry based numerical simulator often utilized for this kind of analysis is the OLGA™ by Schlumberger. It is a multiphase flow simulator capable of performing flow simulation under steady state and transient conditions. By comparison it outperforms many of its contemporaries. OLGA covers both aspects of surface and sub-surface production for well networks, flowlines, risers, to mention few.

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2.1.2 Input Data

Field data is quintessential to be able to perform analyses. The kinds of data to be utilized includes fluid properties data, production field data for the deep offshore location, riser geometry and design properties and gas injection schedule for the gas lift.

2.1.2.1 Geometric Data for Pipeline and Riser

In designing the OLGA model, the flowline-riser geometry is an essential input and is a function of the seabed geometry/topology which is specific to the case study being analyzed. The input data is presented on Table 1 below and was used to define the flow geometry used in the design of the original base case model in Figure 2 below, where the inlet/source is the subsea manifold, and the separator is positioned at the topside

Table 1: Input Data for Flowline-Riser Geometry

Pipe no.	Branch	Label	Diameter	Roughness	Length	Elevation
1 - 1	BRANCH-L	Manifold outlet	0.254 m	2.8E-05 m	151 m	0 m
1 - 2	BRANCH-L	Pipe-2	0.254 m	2.8E-05 m	355.217 m	-0.2 m
1 - 3	BRANCH-L	Pipe-3	0.254 m	2.8E-05 m	514 m	0.2 m
1 - 4	BRANCH-L	Pipe-4	0.254 m	2.8E-05 m	514 m	-0.1 m
1 - 5	BRANCH-L	Pipe-5	0.254 m	2.8E-05 m	521.5 m	-0.1 m
1 - 6	BRANCH-L	Pipe-6	0.254 m	2.8E-05 m	506.22 m	0.2 m

1 - 7	BRANCH-L	Pipe-7	0.254 m	2.8E-05 m	481.44 m	0.2 m
1 - 8	BRANCH-L	Pipe-8	0.254 m	2.8E-05 m	481.45 m	-0.2 m
1 - 9	BRANCH-L	Pipe-9	0.254 m	2.8E-05 m	486.5 m	-0.2 m
1 - 10	BRANCH-L	Pipe-10	0.254 m	2.8E-05 m	408.109 m	-2.8 m
1 - 11	BRANCH-L	Riser	0.203 m	2.8E-05 m	1293.644 m	1278 m
1 - 12	BRANCH-L	To separator	0.203 m	2.8E-05 m	99.504 m	15 m

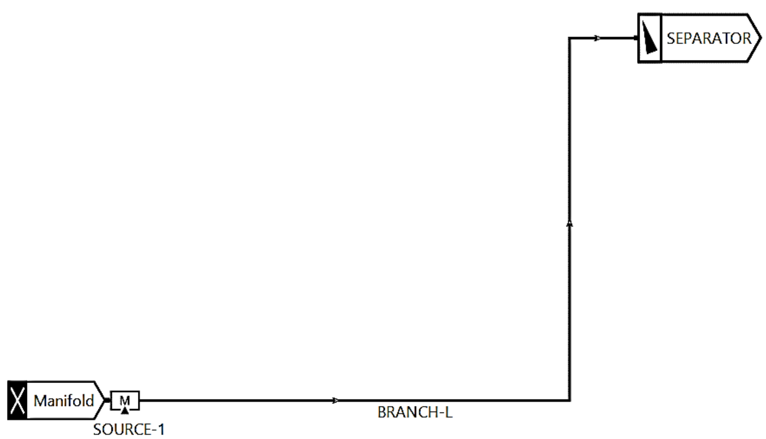

Figure 1: OLGA Base Case model

2.1.2.2 Fluid Composition Data (PVT)

The three-phase fluid file that is in-built in OLGA was applied in the fluid PVT calculations based on the mole percentage of each constituent that made up the well. The constituents of the simulation fluid are presented on Table 2

Table 1: Fluid Composition Data for OLGA in-built "hydr-slug-comp.tab" fluid file.

S/No	Fluid Components	Molar Volume (%)
1	H_2O	39.63881
2	N_2	0.407268
3	CO_2	1.776030

4	C_1	38.26517
5	C_2	5.7934370
6	C_3	3.3648230
7	n-C_4	1.5676730
8	n-C_5	0.9372304
9	n-C_6	1.1503570
10	C_7	1.1443480
11	C_8	0.8922555
12	C_9	0.5324501
13	C_{10}-C_{12}	1.0404790
14	C_{13}-C_{15}	0.8154374
15	C_{16}-C_{18}	0.6250660
16	C_{19}-C_{21}	0.4794017
17	C_{22}-C_{25}	0.4701456
18	C_{26}-C_{29}	0.3300993
19	C_{30}-C_{35}	0.3203112
20	C_{36}-C_{45}	0.2686713
21	C_{46}-C_{80}	0.1805267
		99.9999902

2.1.2.3 Gas lift fluid Properties

The average daily composition of the process gas injected at the riser base is shown below in Table 3. These gas properties were obtained from an inline chromatograph at the outlet of the gas export compressors. The gas has been dehydrated to a dew point of -27.15 ^{0}C at 190 Bar. The gas inject has a density of 220.97 Kg/m^3 and a standard density of 0.8965 Kg/m^3 @ 15^{0}C. This gas is taken at a temperature of 44.9 ^{0}C at 190Bar

Table 2: **Fluid property of the inlet gas.**

Components	**Composition (Mol %)**

Methane (CH_4)	79.8798
Ethane (C_2H_6)	9.7837
Propane (C_3H_8)	5.6018
N-Butane (nC_4)	1.4647
Iso-Butane (iC_4)	1.4560
N-Pentane (nC_5)	0.3016
Iso-Pentane (iC_5)	0.4800
Hexanes (C_{6+})	0.3981
Nitrogen (N_2)	0.0675
Carbon Dioxide (CO_2)	0.5668
TOTAL	100.0000

2.1.2.4 Pipeline Inlet Flow Parameters

The oil fed into the flowline is commingled at the subsea manifold from several wells with an overall mass flowrate of 15kg/s to generate homogenous oil with the following parameters in Table 4.

Table 3: Oil Parameter at the Inlet of the Flowline

Parameter	**Value**
Oil Production	5150.91 bbl/day
Gas Production	16.145 MMscf/d
Water Production	1669.25 bbl/day
Liquid production	6820.17 bbl/day
GOR	653.98 Sm^3 /Sm^3
Water-cut	24.48%
Oil gravity	38.67^0 API, 829 Kg/m^3

2.2 Methods

To initialize the analysis, the riser system would be designed using simulator, based on design parameters gathered - this would serve as the base case model. Two different alterations of this base case model would then be simulated for the two mitigation techniques being considered. Analysis would then be conducted on the simulation to produce results for the different cases.
A comparative analysis approach would then be adopted for the performance evaluation by the use of appropriate charts and/or graphs.

Figure 3 is a flow chart describing, in summary, the steps employed to arrive at results in the investigations done in this research work. This workflow is detailed, and it is repeatable for results as can be observed in the chart.

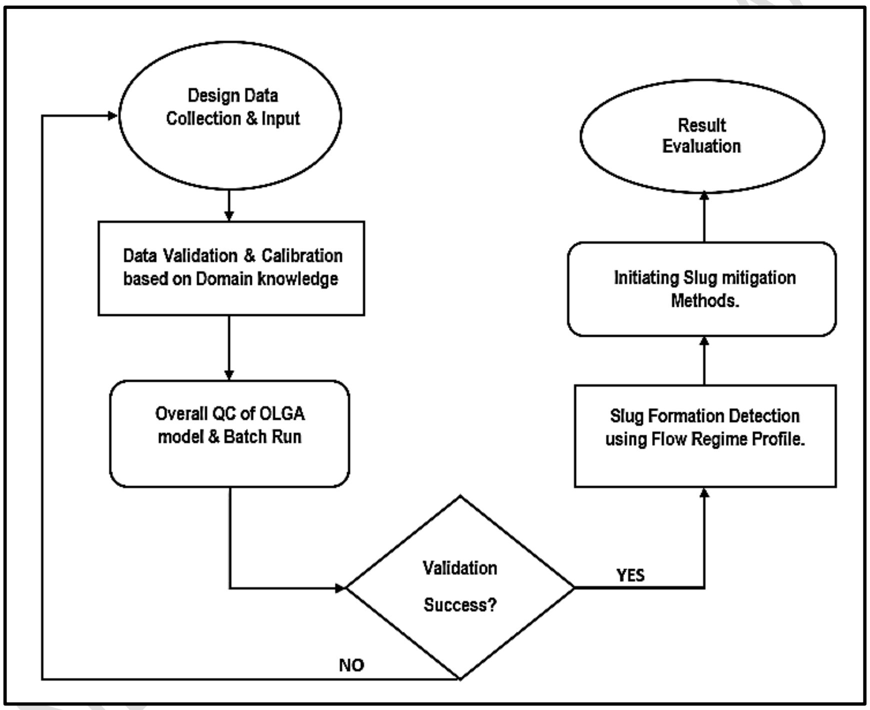

Figure 2: **OLGA Workflow**

3. RESULTS AND DISCUSSION

3.1 Identification of Flow Regimes Along the Length of Pipe

An important stage in the analysis done in this research work, is to identify the locations and/or sections of pipe where the slug flow regime is likely to develop, especially because emphasis is laid on slugging occurring in the riser section – which is more hydrodynamic slugging as opposed to terrain slugging that occurs mostly along the flowlines. The tool within the OLGA software that can aid detection along the pipeline is the ***fluid regime profile plot*** *– ID against* ***pipeline length***

This profile plot was done iteratively at different times within the overall simulation of time of 30,000s beginning from time 0s. Thirty-thousand iterative plots were made in this case, but the selected plots were for times, 0s (at the start of simulation), and 15,000s displayed on Figure 4 to Figure 5.
A close observation of these plots' highlights that along the flowline-riser profile, there are 3 fluid regimes present, which are Stratified, Slug flow and Annular flow. On the average, within the selected simulation times, slug flow occurred between the pipe length 4514m to 5767m (which is the riser section)

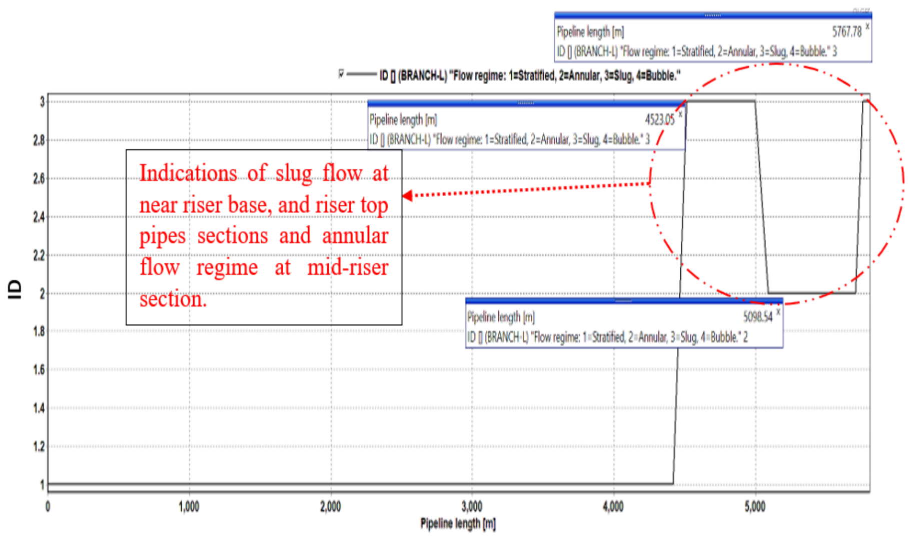

Figure 4 **Flow regime distribution along pipe profile at 0s**

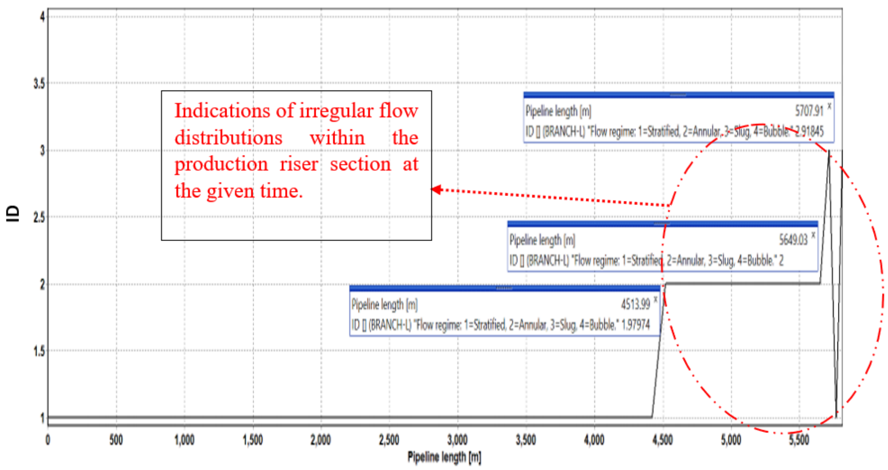

Figure 5. **Flow regime distribution along pipe profile at 15000s**

3.2 Analysis of Slugging Behavior in Pipe Sections.

There are two parameter trends usually utilized to study the impact of slugging in pipelines. These are: total liquid volume flow (QLT) and pressure (PT) trends – which are essentially frequency plots and can be analyzed as such.
To confirm the sections affected by slugging, profile plots of total liquid volume flow (QLT) for the different times as displayed on Figure 6 to Figure 7are utilized. These plots highlight hydraulic surges in the same length sections identified in the previous section and close observation of Figure.6 and Figure.7 showing the surges has been marked out.

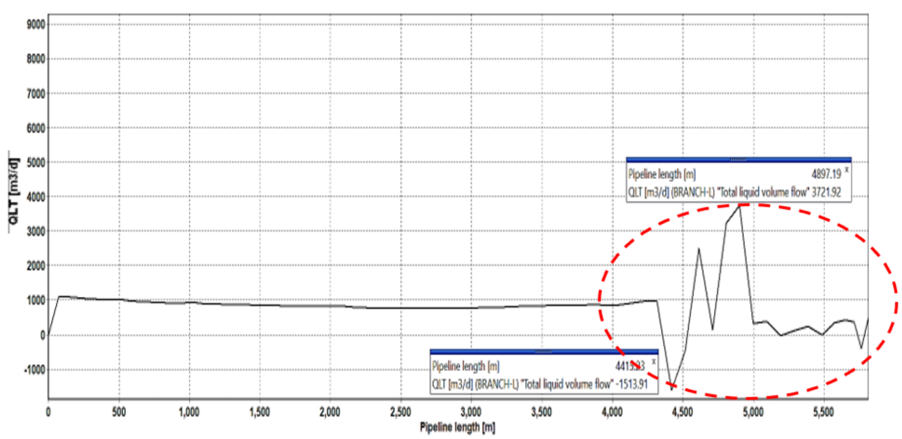

Figure 6. **Total Liquid Volume Flow profile at 15,000s**

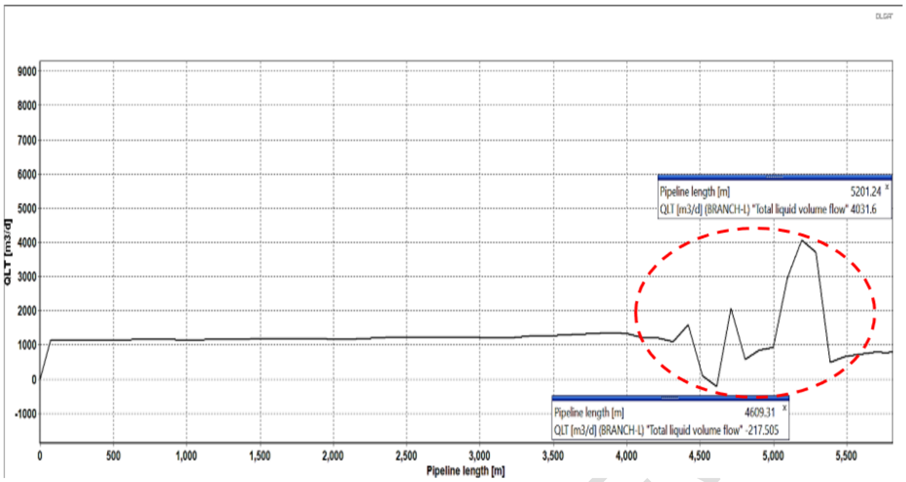

Figure 7. Total Liquid Volume Flow profile at 30,000s

There is a higher surge amplitude identified around riser sections, these surge amplitudes can be said to be directly proportional to the severity of the slugging.

The QLT trend plot for 'Riser Section' in Figure 8 shows liquid flow surge amplitudes as high as 9120m^3/day with a pattern closely matching hydrodynamic slugging which occurs mostly in risers. Similarly, the pressure trend was generated for the scenario/case before attenuation or mitigation measures were applied as displayed on Figure 9, reasonable pressure oscillations can be observed ranging between 29 to 22.7 bar.

It can be observed that slugging in both flowline and risers is characteristic of hydraulic surging and pressure oscillations which can lead to operational challenges as well as damage to equipment. The possible effects are stress impacts on pipeline sections and possible failure (such as: rupture, burst, collapse and even snaking effect – which is very popular with subsea pipelines), as well as level fluctuation at separator which may lead to inefficient separation because of high GOR.

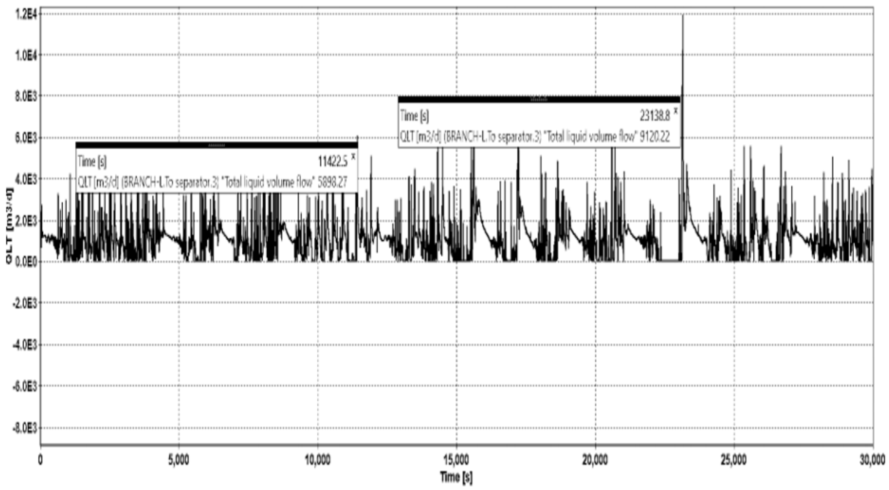

Figure 8. **Total Liquid Volume Flow Trend for Riser Section**

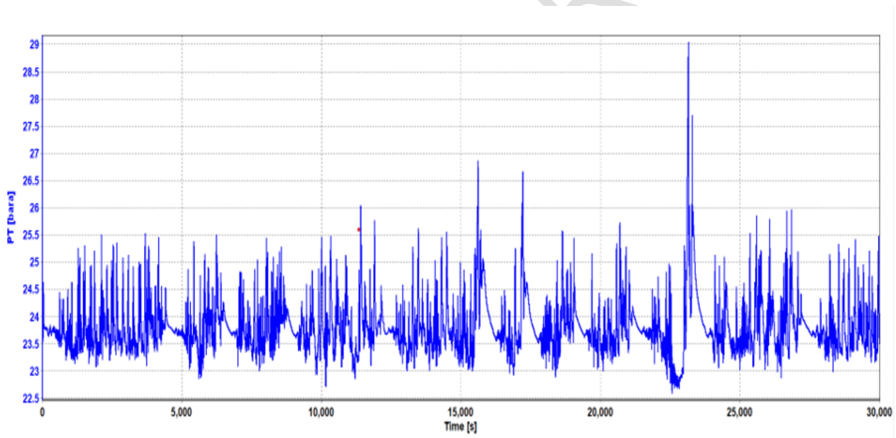

Figure 9. **The initial pressure trend (PT) for riser section before attenuation**

3.3 Application of Attenuation Method I – *Topside Choke Opening Adjustment.*

In this method of topside choking, simulation was done for various choke opening percentages for a duration of 30000sec (8.33Hr). With reduction in the choke opening from 80% to 5% (Figure 10 to Figure 13), it is observed that the downstream pressure oscillation regime reduced significantly, from pressure range of 25.7-29.0 bar (without choking) to a pressure range of 22.5-22.8 bar (at 5% choke opening), this behavior clearly shows that the slugging effects has been addressed.

However, observing the behavior of the pressure upstream the choke, shows expected pressure increase upstream the choke as the choke opening reduction takes place, this also implies a reduction in total production from the riser. Hence it is pertinent to find a choke opening, with minimum slug, which could affect the integrity of downstream equipment and with optimum production.

With the choke at 50% opening, Figure 11, the upstream pressure is seen to oscillate mainly within the range of 22.75 and 24.5 bar, thus indicating a more reduced stress on the riser components yet offering a downstream pressure range of 22.5-22.8 bar which implies reduction in slugging, thereby ensuring protection for the downstream equipment. The choke being at 50% opening for the case modeled is therefore suggested as the optimum choke opening for slug attenuation and production optimization.

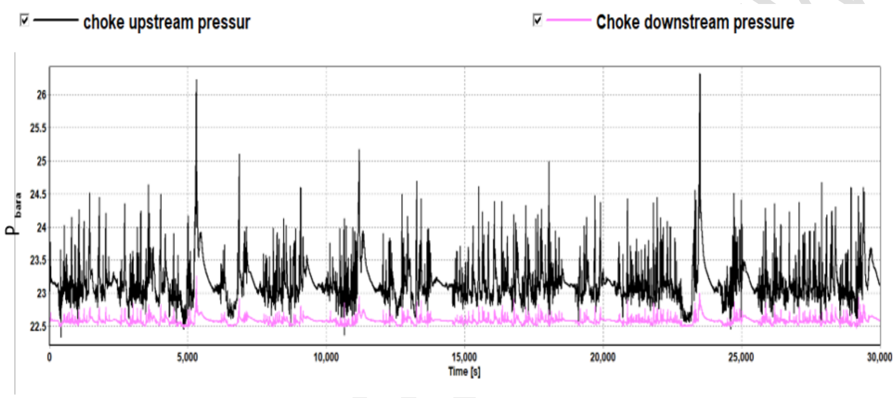

Figure 10. **Choke Opening At 80%**

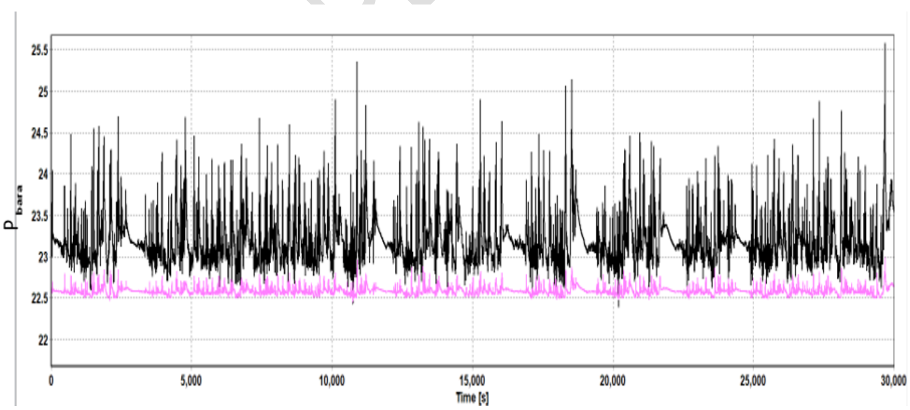

Figure 11. **Choke Opening At 50%**

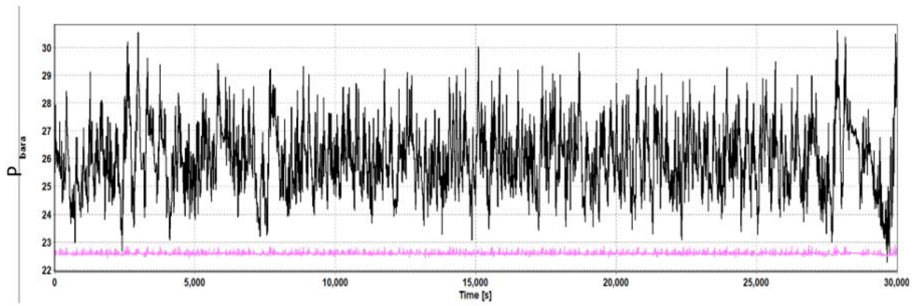

Figure 12. **Choke Opening At 10%**

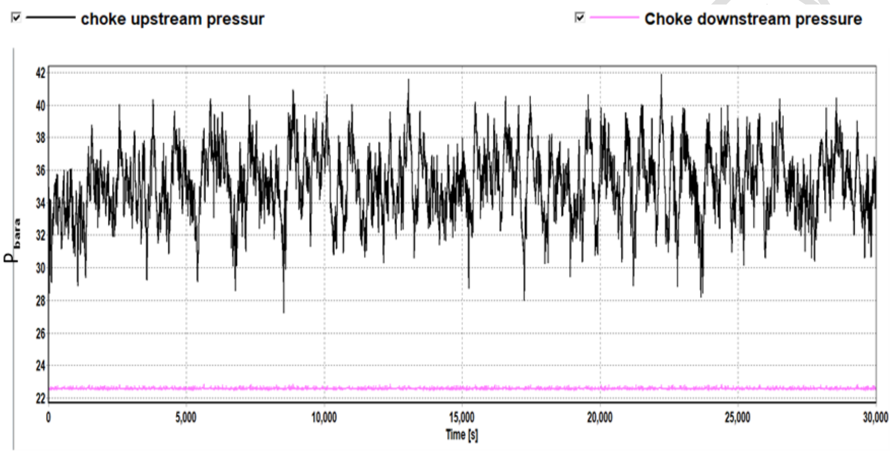

Figure 13. **Choke Opening At 5%**

3.4 Application of Attenuation Method II – *Riser Base Gas lift (RBGL).*

The riser base gas lift (RBGL) method as the name implies, was designed in this case to supply gas at the last section of pipeline before the riser or the first riser section. One key challenge with the deployment of this technique, is selection of an optimal position to inject gas and the optimal volume of gas to be injected (i.e., mass flow) to reduce the fluctuations. For this research, the first section of riser was selected to position gas lift valve with a gas flow rate of 1.2 kg/s.

On deployment of RBGL, in this case study, we can see that the chaotic fluctuations of riser flow rate and pressure trend have been stabilized tremendously. For the Pressure Trend, displayed in Figure 14, we can observe a pressure fluctuation of about 0.15bar difference at the beginning of simulation but in about 5000 secs, pressure oscillations are negligible, and maintained approximately at 22.58 bar, before entry into the separator.

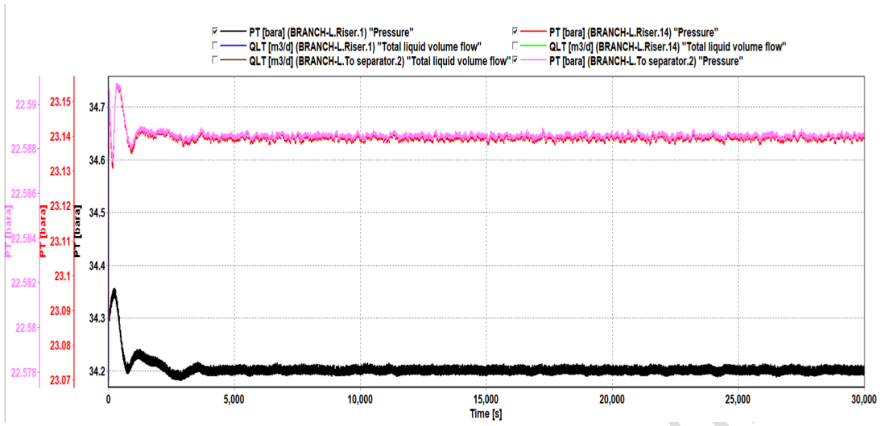

Figure 14. **Riser Pressure trend (PT) on application of RBGL**

4. CONCLUSION

In alignment with the aim of this study, two methods of slug attenuation were applied to a case study, modeled, and simulated in OLGA™ (a multiphase numerical simulator) and their performance analyzed and evaluated. The selected methods in this research were: Topside choking and riser base gas lift (RBGL) out of the many notable techniques suggested and developed by researchers in this field. On simulation of the modeled case study, both terrain slugging (which is mainly due to sharp seabed elevations) and hydrodynamic/severe slugging at the riser were observed – though the effect of attenuation techniques applied was focused on the riser sections just before the separator.

For the ***topside choking***, the underlying principle was to reduce the incoming line diameter to establish a stable flow regime. The main challenge with deploying this technique is to determine optimal choke configuration that can alter the operating condition such that slug flow and associated fluctuations are stabilized to a value that is as low as reasonably possible, while still maintaining efficient production rate. In this research, choke settings of 80% - 5% were simulated on OLGA and the pressure trend behavior evaluated, with choke opening at 50% reflecting optimal choke position.

Simulating ***RBGL*** application to the scenario, gas was supplied at the first section of riser even though it can be suppled at the last flowline section, the slug was observed to be completing eliminated after a simulation time of 5000sec and pressure oscillation maintained at 22.58 bar. The main challenges in the deployment of this technique being to select optimal injection position and the mass flow rate of gas injected.

When compared with the topside choke method for the case study, it can be concluded that the RBGL technique performed better for the scenario created. It is however worthy of note, that the performances of these methods are a function of the selected individual design parameters in the model – which may not necessarily be the optimal values.

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