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NUMERICAL SIMULATION OF THE INFLUENCE OF SEVERE SLUGGING ON OFFSHORE PRODUCTION SYSTEMS

Tony Herbert Freire de Andrade [1]

[1,2,3,4,5,6] Universidade Federal de Campina Grande

[1] tony.herbert@professor.ufcg.edu.br

Wayne Gabriel Nóbrega Firme [2]

[2] engwaynenobrega@gmail.com

Átyla Matheus de Araújo Costa3 [3]

[3] atyla_matheus_costa@hotmail.com

Paulo Vitor Silva Ramos [4]

[4] paulovitor.srm@gmail.com

Tales Dmitri Araujo Lopes [5]

[5] tales.dmitri@estudante.ufcg.edu.br

Phillippe Augusto Sales [6]

[6] phillipeaugustoss@gmail.com

Abstract. *The regime's severe slugging flow is a problem commonly encountered in the oil and gas industry, due to the associated production instability. This phenomenon in particular is characterized by cycles of large fluid production followed by periods of low or even zero fluid production, which represents a great challenge to the assurance of multiphase flow. One of the main conditions for the occurrence of the severe slugging phenomenon is the presence of depressions in the production pipelines, which, in turn, are usually found in flowline-riser systems in offshore fields. In this sense, the work focuses on evaluating, through computational tools, an oil and gas production system composed of a flowline-riser to identify the occurrence of severe slugging, as well as the operational verification of the use of choking valves at the top of the riser as an alternative to stabilize fluid flow. Since the use of computational simulation tools is essentially important for determining the technical and economic viability of oil and gas production in oil fields, as they help in the identification and remediation of problems related to the assurance of multiphase flow, the present study uses the commercial one-dimensional multiphase flow simulator, Artificial Lift Flow Assurance Simulation - ALFAsim. This software makes it possible to model and simulate the oil production layouts of composite systems, for example, well-flowline-riser, and therefore predict the occurrence of severe slugging. The graphical analysis of parameters such as volumetric oil flow, holdup, flow pattern, absolute pressure and elevation, displays profiles that correspond to the identification of the severe slugging phenomenon. In addition, to mitigate the occurrence of severe slugging, it appears that the use of choking valves at the top of the riser with an opening of 92.5 % is effective in stabilizing the flow of fluids and, consequently, guarantees operational safety through the entire change in flow pattern in the riser.*

Keywords: *slugging, ALFAsim, flow assurance, multiphase flow.*

1. INTRODUCTION

Multiphase flow can be defined as the simultaneous flow of two or more phases with different and immiscible properties in a pipeline (Martins, 2011). In the petroleum industry the occurrence of multiphase flow is common throughout the fluid path, including production and transportation. This type of flow occurs from the reservoir rock to the separation units, through the production column, risers and lines and then transfers to the refining units (Shoham, 2006). It occurs due to the reduction of pressure and temperature, causing the gas previously dissolved in the oil, depending on the chemical composition of the oil, to be released and be produced together with oil and water from the formation (Brill, 1987).

The correct understanding of how the multiphase mixture behaves during oil well production is of fundamental importance for issues related to the economic return of the field, such as determining pressure drop, liquid fraction, measuring volumetric flow rates of fluids, sizing production systems, and processing and production management (Bannwart *et al.*,

2005). When gas and liquid flow simultaneously in a pipe, the phases distribute themselves in particular configurations, commonly called flow patterns. According to Oyeneyin (2014) flow patterns can be grouped into four main classes, and each class can be subdivided into subclasses for a more precise description: Stratified flow (Subclasses: smooth stratified, wavy stratified); Intermittent flow (Subclasses: elongated bubble, gulps, agitation); Annular flow; Bubble flow (Subclasses: bubble, dispersed bubble).

According to Shoham (2006), each flow pattern will present changes in the hydrodynamics of the flow, as well as the equations of pressure gradient, momentum balance, and mass that change dramatically in each pattern. Still according to Shoham (2006), the flow patterns depend strongly on the pipeline diameter, slope, and flow rates of each phase. Among the two-phase flow patterns presented, the slug flow stands out as one that requires greater effort in its characterization and modeling, due to the remarkable characteristics of the spatial distribution between phases, which generates intermittency in the flow.

Peculiar problems associated with such flow geometry are flow instabilities and production losses, pressure oscillations at the riser base, flooding of the separator due to peaks of accumulated liquid, and damage to the separator due to high liquid and gas flow rates (Schmidt *et al.*, 1980). Other slug flow problems include fatigue damage to marine structures especially that imposed by severe slug pattern flow which is usually associated with hydrostatic pressure oscillations and is significantly dominant at the base of an offshore production riser (Sultan *et al.*, 2013).

According to Nascimento (2013) one way to deal with multiphase flow in pipelines, specifically in the petroleum area, is by means of computational fluid dynamics -CFD techniques. There are several software programs on the market that simulate multiphase for a petroleum production system such as, for example, the Artificial Lift Flow Assurance Simulation - ALFAsim, PIPESIM and OLGA.

Ashikawa (2017) performed studies on slug mitigation in offshore systems using OLGA software and obtained effective results in containing the slug flow pattern with the help of a choke valve. Coutinho *et al.* (2020) developed research to compare the efficiency of the results of the implementation of a choke valve in OLGA and PIPESIM software, both with satisfactory results in controlling the flow behavior.

Therefore, researche involving computational tools to represent a production system and identify flow assurance problems through software such as OLGA and PIPESIM is quite widespread in the scientific environment, and presents satisfactory results. On the other hand, the use of ALFAsim as a support tool for computer simulations is scarce in the literature, since it is a new software on the market and there are not yet a significant number of studies using this tool. Therefore, in the present study ALFAsim is used to identify, analyze, and mitigate the golfing pattern.

ALFAsim is a 1D dynamic multiphase flow simulator that combines a robust mathematical formulation with an advanced numerical strategy to provide a computationally efficient simulation experience with an intuitive interface (ESSS, 2023).

In view of this, the main objective of this study is to verify the efficiency of ALFAsim as a multiphase simulator in the representation of an offshore production system consisting of a well, flowline and riser. In addition, the work identifies and analyzes the occurrence of the flow pattern in gulps through the analysis of parameters such as oil flow, the flow pattern identified by the software and absolute pressure, verifying the application of a choke valve as a methodology to mitigate the occurrence of slugging.

2. BIBLIOGRAPHIC REVIEW

2.1 Multiphase Flow

Multiphase flow can be defined as simultaneous flow consisting of two or more phases with different and immiscible properties in a pipe. In this type of flow no strict distinction is made between the concepts of phase and component, but rather the number of interfaces present in the flow. In the case of oil-water-gas flow we have the presence of two interfaces, liquid-liquid-gas (water, oil and gas, although the mixture is considered biphasic (Silva *et al.*, 2000).

This type of flow represents a great difficulty in engineering because there are a number of fluids with different density and viscosity characteristics passing through the same space. Let's say that a pipeline is planned for the flow of oil of oil, when there is the addition of the gaseous phase in this pipeline the diameter by which the flow of oil occurred is no longer the same, because the space is being divided unpredictably between the phases (Conrado *et al.*, 2020).

Liquid-gas mixtures do not move as a whole, instead one phase flows relative to another. The denser phase tends to flow slower and requires more time to traverse the same length of pipe (Martins, 2011).

When a gas and liquid flow simultaneously in a pipe, the phases are distributed in particular configurations, there is a unique distribution of the phases in the two-phase mixture, commonly called flow patterns. Remarkable changes in hydrodynamics and mathematical equations occur in each pattern type. Figures 1 and 2 illustrate horizontal and vertical flow patterns, respectively.

The ALFAsim software considers five flow patterns: stratified, annular, dribble, bubbles, and dispersed bubbles. The simulator identifies which flow pattern is occurring by means of a flow map, illustrated in Figure 3.
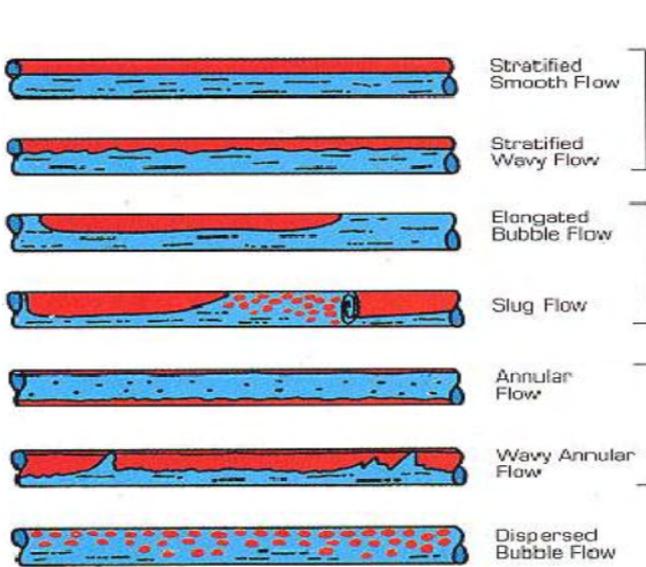
Figure 1. Horizontal Flow Patterns
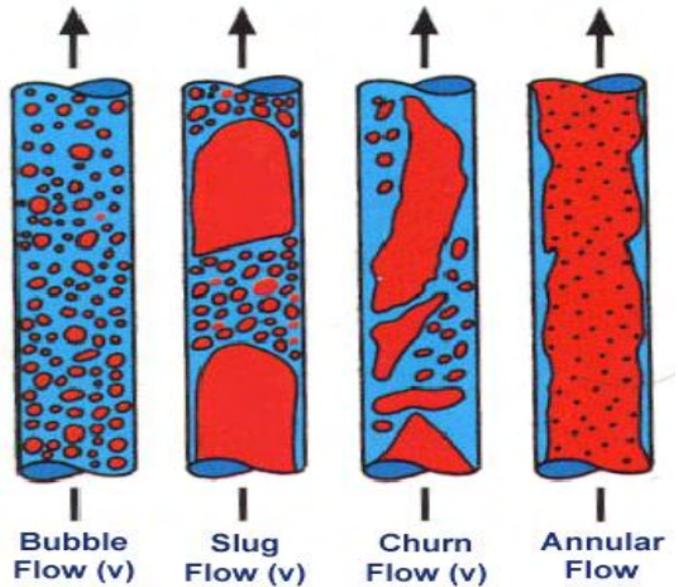Source: Oyeneyin (2014).
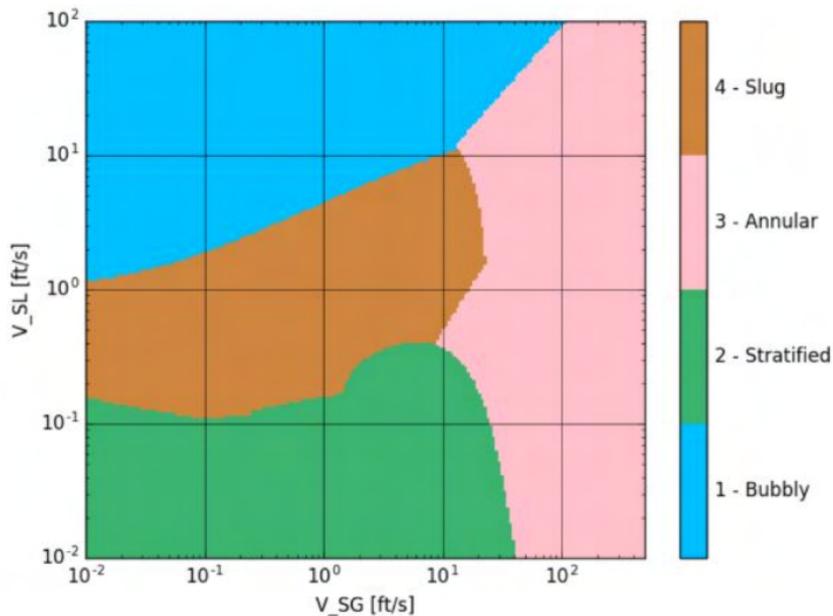
Figure 2. Vertical Flow Patterns
Source: Oyeneyin (2014).

Figure 3. Flow Pattern Identification Map
Source: ESSS (2023).

2.2 Slug Flow Pattern

This pattern is characterized by gas flowing in the form of a series of pockets or gulps of similar diameter to the column. The gas gulp flows through the center and is separated from the pipe wall by a small liquid film. Both liquid and gas slugs have a significant effect on the pressure gradient (Nascimento, 2013).

Slug flow initiates oscillations, places excessive demands on separation and operation, and increases equipment wear. Large peaks in liquid production can cause poor performance, separator shutdowns, high-pressure firings, or burnout. This phenomenon can be characterized by periodic changes in pressure and gas-liquid flow (Tang and Danielson, 2006).

According to Taitel (1986), three basic conditions are required for slugging to occur: the subsea pipeline must have a downward slope followed by a riser, the flow in the pipeline must be stratified, and the rate of pressure increase at the base of the riser due to liquid accumulation must be greater than the increase in gas pressure in the pipeline.

The severe slugging process consists of four steps as described by Taitel (1986): Formation of the piston or liquid slug (step a); Movement of the liquid slug towards the separator (step b); Explosion of the bubble - blowout (step c); Return of the liquid to the riser base - fallback (step d). The steps described are illustrated in Figure 4 below:
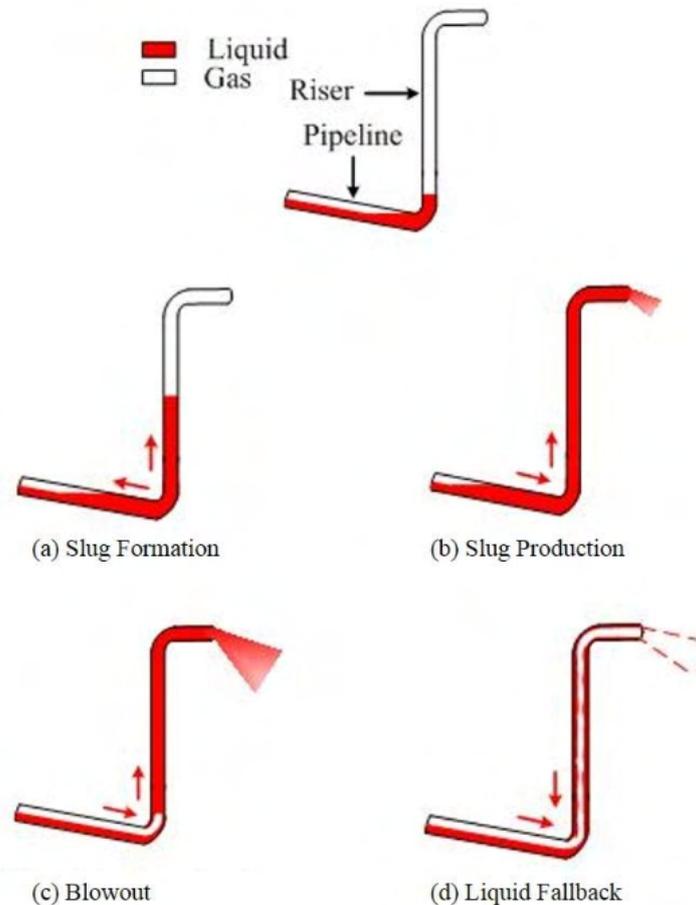

Figure 4. Slug Cycle
Source: ESSS (2023).

The liquid builds up in the lower part of the pipe preveting the gas from passing through and is compressed until the gas pressure builds up sufficiently to counteract the hydrostatic loading of the liquid column inside the riser. The gas expands and pushes the piston or slug of the liquid column ahead of it toward the separator. When the previously compressed gas at the base of the pipe manages to overcome the hydrostatic pressure imposed by the liquid, the liquid column flows at a high velocity. This phenomenon is called a blowout. When much of the pressure caused by the gas blockage is released, the liquid returns to the base of the pipe, which causes a new blockage for the passage of gas and starts a new cycle of bubble formation. In this way, the severe slugging flow pattern is possible because of the compressibility property of the gas.

2.3 Slug Flow Pattern Remediation

There are different means to achieve the reduction or complete removal of the slug pattern from the medium and thus mitigate the problems caused by this runoff. It is possible to make changes in structural design by altering pipe diameters, for example, which leads to favorable changes in the variables that influence and aid the development of slugs. Operational changes can also be made by implementing elements that help control the gulps, the most common means are the choke valve and lift gas injection.

According to Shoham (2006) lift gas injection increases fluid velocities and brings the flow closer to annular behavior. A large amount of gas is required to stabilize production, resulting in reduced slug size and cycle time.

Schmidt *et al.* (1980) found experimentally that they could stabilize the fluid flow by restricting the flow at the top of the riser by implementing a choke valve.

According to Sachdeva *et al.* (1986) the choke valve can be compared to a restriction, whose main purpose is to control and optimize production. However, other objectives of choke valves are to maintain a permissible flow rate at the

wellhead, control the production flow rate, protect surface equipment, and maintain a back pressure upstream of the valve to protect the well.

The use of the choke valve generates a higher flow resistance proportional to the fluid velocity due to the increase in back pressure. Increasing the back pressure also means a lower flow rate and lower well productivity (Júnior, 2011).

Knowing the valve installation, as well as the parameters of physical readings of pressure and mass percentage of each composite phase of the fluid passing through the choke valve, some authors propose expressions to calculate the critical condition and mass flow rate, however many of these proposed models have tuning parameters, obtained based on experimental data. Thus, the critical condition and the mass flow rate are terms to be investigated, as are the different physical effects that alter the calculation of such parameters (Buffa, 2017).

Choke valves can be of the positive type, where it is not possible to adjust the orifice diameter, or they can be of the adjustable type, where it becomes possible to adjust the effective orifice diameter of the valve used. As Thomas (2001), increasing the opening of the valve reduces the pressure loss of the fluid as it passes through it, with a consequent decrease in downhole flow pressure.

3. MATHEMATICAL EQUATIONS

3.1 Conservation equations

To calculate fluid flow in pipes, the ALFAsim tool integrates the laws of conservation of mass, momentum and energy. In this work, the equations that describe the phenomenon are those of the conservation of mass and momentum and are written in 1 and 2. These equations are derived by neglecting the source and sink terms due to phase change, axial diffusion, non-frictional interfacial forces, as well as distribution effects in the flow cross-section. In addition, the tool uses a multiphase model strategy that allows for an arbitrary number of fields, phases and layers.

The system of one-dimensional non-linear equations is obtained through an averaging process from the 3d local instantaneous equations. The resulting mass balance equation for each field k is:

$$\frac{d(\alpha_k \rho_k)}{dt} + \frac{d(\alpha_k \rho_k u_k)}{dt} = 0 \tag{1}$$

Where α_k is the volume fraction, ρ_k is the mass density and u$_k$ is the velocity.
The momentum balance equation for each field k is given by:

$$\frac{d(\alpha_k \rho_k u_k)}{dt} + \frac{d(C_k^u \alpha_k \rho_k u_k u_k)}{dx} = -\alpha_k \frac{dp_k}{dx} - \alpha_k \rho_k gsen\theta + (p_{ki} - p_k)\frac{d\alpha_k}{dx} - \frac{\tau_{wk} S_{wk}}{A} \pm \frac{\tau_i S_i}{A} \tag{2}$$

Where θ is the pipe slope, A is the cross-sectional area, $\tau_{wk} S_{wk}$ is the wall shear stress τ_i Si / A is the interfacial shear stress, S_{wk} is the wetted perimeter of the wall, Si, is the wetted perimeter of the interface, and C$_k$ is the k-phase distribution parameter, which is set to 1 by default.

3.2 Valve

According to Thomas (2001), to calculate the opening degree of a choke valve, one can use the correlation shown by Equation 3:

$$P_{mont} = \frac{18,24 \cdot q \cdot RGL^{0,5}}{S^2} \tag{3}$$

Where: P$_{mont}$ = pressure upstream of the valve (kg/cm²); Q = flow rate (m³/d); RGL = gas-liquid ratio (m³/m³); S = flow regulator opening (/64 inch);

To use the presented correlation it is necessary that critical flow occur, the flow velocity must be equal to or greater than the sound velocity in the medium. For situations in which there is no critical flow, the available correlations are more complicated and inaccurate, and trial and error can be used to determine the valve opening more efficiently.

The ALFAsim software takes into account to calculate the flow coefficient (Cv) of the choke valve the equation 4:

$$C_v = mk\sqrt{\frac{SG}{\Delta \cdot P_b}} \tag{4}$$

3.3 Flow pattern

The software considers five flow patterns: stratified, annular, slug, bubbly and dispersed bubbly. The Unit Cell Model is used as the central model for the flow pattern determination. If the model succeeds in the evaluation of the slug flow variables then the flow regime is slug, otherwise (if it fails) the regime is defined depending the type of failure.

In the case where no root is found for the film liquid volume fraction, the flow is defined as stratified if $\theta \leq 10$, otherwise it is bubbly. Besides that, if

$$F = \frac{L_S}{L_S + L_f} \pm 1 \tag{5}$$

the flow is bubble.

If $F \leq 0$ the flow is separated defined as stratified if $\theta < 10$ and annular if $\theta > 10$.

Horizontal flow tends to be more complex than vertical flow, due to the asymmetry in the flow induced by gravity acting normal to the flow direction. Because of this force, the denser fluid (liquid) tends to occupy the bottom of the pipe. Figure 5 illustrates the forces acting during flow.
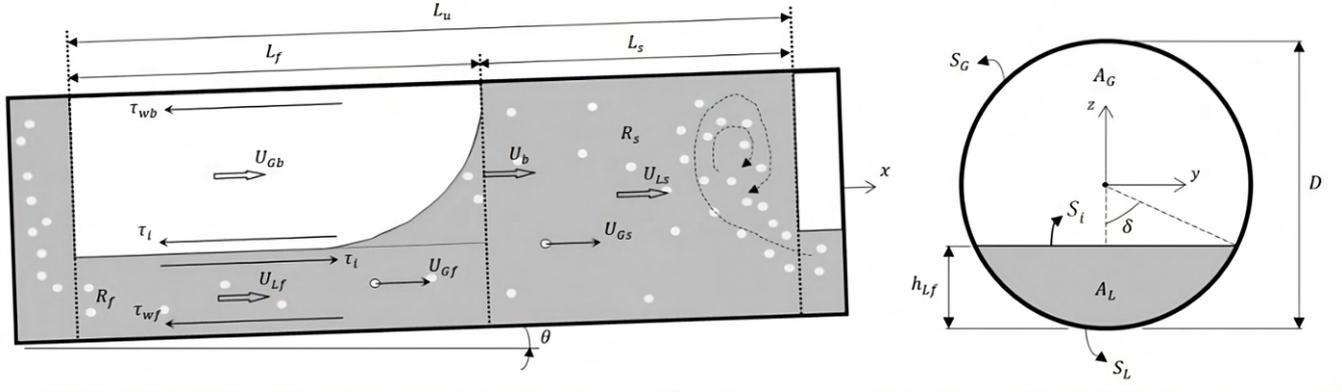
Figure 5. Typical structure of the unit cell in horizontal or near-horizontal flows
Source: ESSS (2023).

Furthermore, there are two more conditions for the stratified flow definition and two more for the annular flow definition. So, for the transition to stratified regime, we have:

$$|u_g - u_l| \leq \left(1 - \frac{h_l}{D}\right) \sqrt{\frac{(\rho_l - \rho_g) \, g A_g \cos\theta}{\rho_g \frac{dA_l}{dh_l}}} \tag{6}$$

$$|u_l| \leq \sqrt{\frac{gD\left(1 - \frac{h_l}{D}\right)\cos\theta}{f_{wl}}} \tag{7}$$

The stratified arrangement is characterized by the separation of the liquid and gaseous flows, where the liquid flows in the lower part of the duct, while the gas moves in the upper part. The two phases flow separated by a smooth interface and typically occurs for low liquid surface velocities.

For transition to annular regime, it is given by:

$$\tilde{h}_L = \frac{h_L}{D} < 0.35 \tag{8}$$

in which h_L is the liquid height. If the flow is vertically downward, then the condition applies to the liquid volume fraction ($\alpha_l < 0, 35$).

The annular regime is particularly difficult to analyze analytically due to the large number of number of types of forces that need to be considered. Both viscous and inertial forces are relevant in the liquid film; surface tensions control the stability of the film at the interface, while drag forces along it determine flow and gravitational effects control the direction of effects control the direction of flow.

4. METHODOLOGY

4.1 Base Case

The offshore production system consisting of well-flowline-riser, modeled for a one-dimensional transient simulation, considered a horizontal well with a total length of 3200 m and an inner pipe diameter of 8.5 in. The reservoir pressure

and temperature were set at 320 bar and 60 °C, respectively. Furthermore, the volumetric flow rate of the well for this simulation is set to 1200 m³/d.

The layouts used in the simulation are illustrated in Figures 5 and 6. Other elements such as process time and flowline/riser dimensions used are described in Table 1. Figures 8, 9 and 10 illustrates the geometric layout in space on a two-dimensional X and Y plane for the well, flowline and riser respectively.
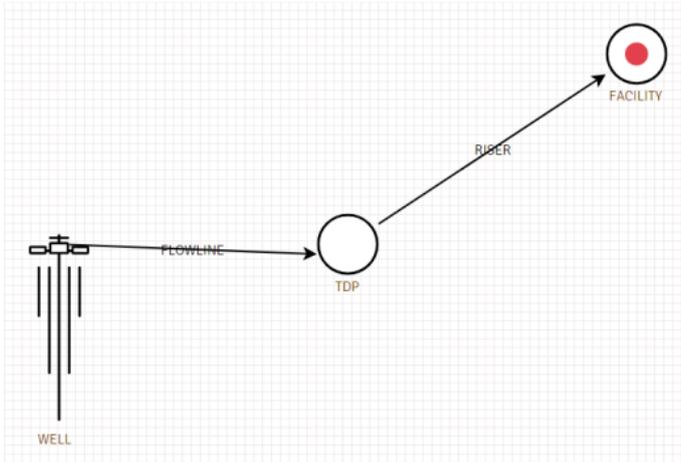

Figure 6. ALFAsim interface visualization for production system layout
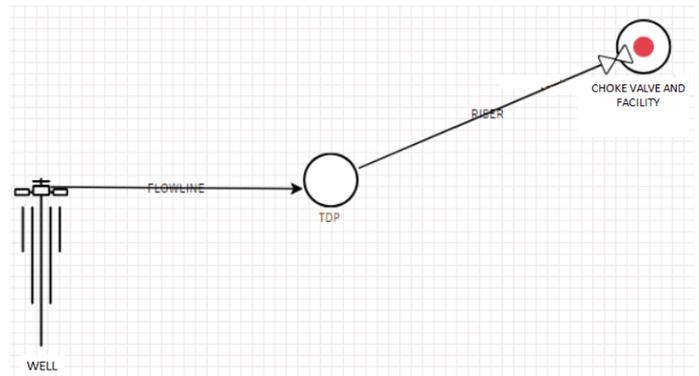
Figure 7. ALFAsim interface visualization for production system layout with choke valve

Table 1. Data Used in Production System Modeling

| PROCESS TIME	
Tempo Inicial	0h
Tempo Final	24h
FLOWLINE CONDITIONS	
Comprimento	4000 m
Elevação	- 200 m
Diâmetro Interno	6 in
Pressão Absoluta (0 m)	200 bar
Pressão Absoluta (4000 m)	125 bar
Fração de Volume (0 m)	0,2 gás / 0,8 óleo
Fração de Volume (4000 m)	0,4 gás / 0,6 óleo
Temperatura	4° C
RISER CONDITIONS	
Comprimento	3187,61 m
Elevação	2000 m
Diâmetro Interno	6 in
Pressão Absoluta (0 m)	125 bar
Fração de Volume (0 m)	0,4 gás / 0,6 óleo
Temperatura (0 m)	4° C
Temperatura (3187,61m)	25° C
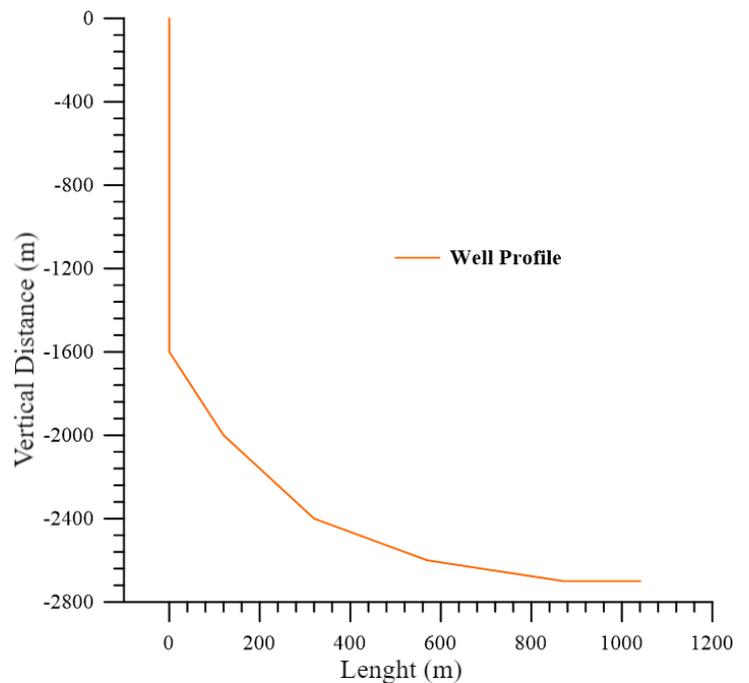
Figure 8. Geometric profile of the Well
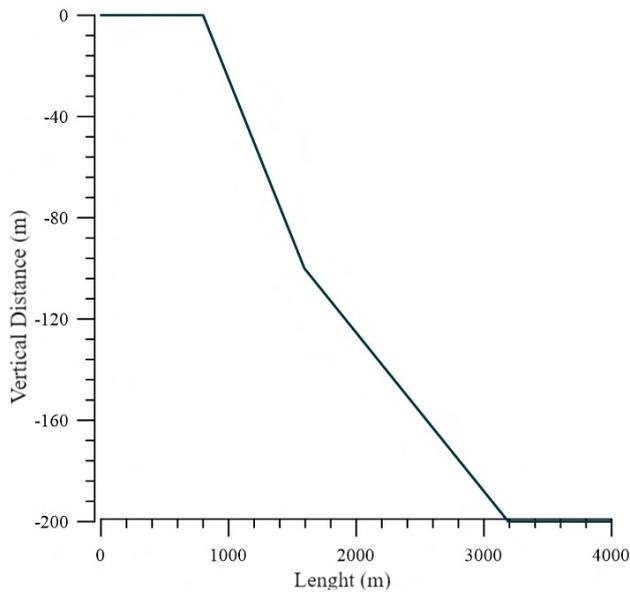
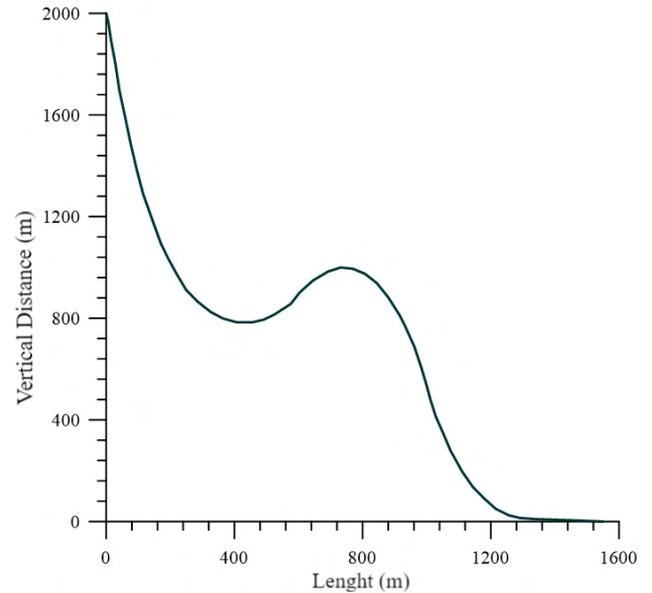Figure 9. Geometric profile of the Flowline

Figure 10. Geometric profile of the Riser

4.2 Choke Valve Opening and Flow Coefficient Values

According to Thomas (2001), presented in the theoretical foundation, it is possible to use trial and error to determine the choke valve opening with greater efficiency. Based on this, parametric rounds were performed (a tool contained in ALFAsim that allows to alternate the values of the same variable during the simulation), creating a variable called "opening", and the valve openings were tested at 92.5 %, 88 % and 77.5 %. The valve was installed at the top of the riser (3140 m). The choke valve flow coefficient values for each opening were extracted from the ALFASim software itself, and are illustrated in Table 2 below:

Table 2. Choke Valve Opening Values with Flow Coefficients

Opening	Flow Coefficients (m³/s)/(Pa^0,5)
1	7.59804e-05
0.925	3.79903e-06
0.880	3.03922e-06
0.775	2.21942e-06
0	0

5. RESULTS

5.1 Identification of the Slug Flow Pattern

It can be noted from Figure 11 that the oscillatory behavior of the oil volumetric flow rate at the end of the riser (3140 m) has high peaks and moments of no production. According to Taitel (1986) severe slugs are an unstable flow pattern as they are associated with large and abrupt fluctuations in flow rate. Therefore, the oil production flow rate of 1200 m³/d gives the production system the slug pattern flow.

It is possible to observe that, according to Figure 12, the flow pattern at the end of the flowline (4000 m) is stratified, which is one of the requirements for the occurrence of the slug phenomenon according to Taitel (1986). It is also possible to verify that throughout the production at the end of the riser (3187 m) there is a slug flow pattern and that, although there are rapid oscillations in the flow pattern, the abrupt fluctuation in the oil flow, observed in Figure 11, provides the system
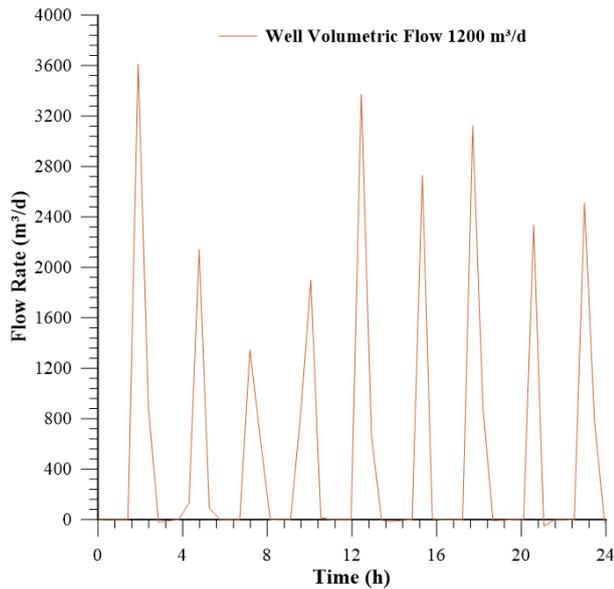
with the slug pattern flow.

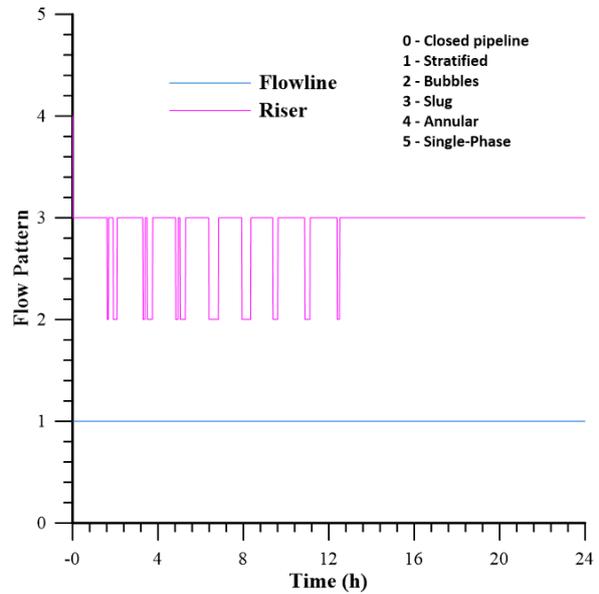Figure 11. Riser Volumetric Oil Flow (3140 m)

Figure 12. Flowline (4000 m) and Riser (3187 m) Flow Pattern

Figure 13 illustrates the liquid holdup along the length/elevation of the entire riser, and one can notice the increase in gas content in the middle as the column elevation level increases. This aids in the development of the slug flow pattern.
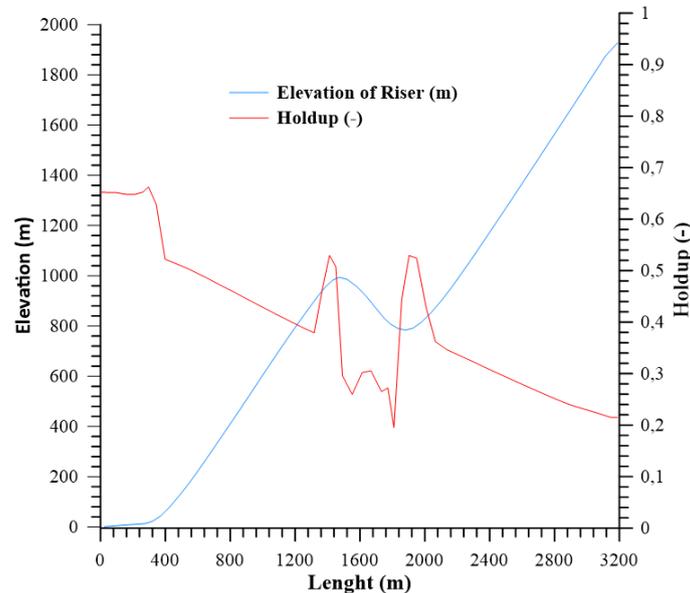

Figure 13. Holdup X Riser Elevation

5.2 Slug Flow Pattern Remediation with Choke Valve

From Figure 14, it can be seen that the oil flow rate of the production system was stabilized in all valve openings tested as of the seventh hour of operational time, and it was no longer possible to observe an oscillatory behavior in the oil flow rate. Similar behavior was described in other works, such as Martins (2022), where after a certain period of simulation it was possible to stabilize the oil flow. However, according to Figure 15, it was verified that the 92.5 % opening offers

the system a lower operating pressure, which provides a more efficient and safer production for the system. According to Júnior (2011), the increase in back pressure generated by closing the choke valve can cause damage to the system and decrease production efficiency.
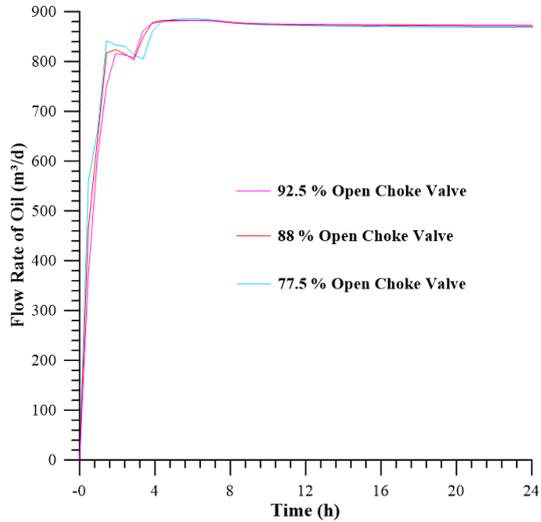

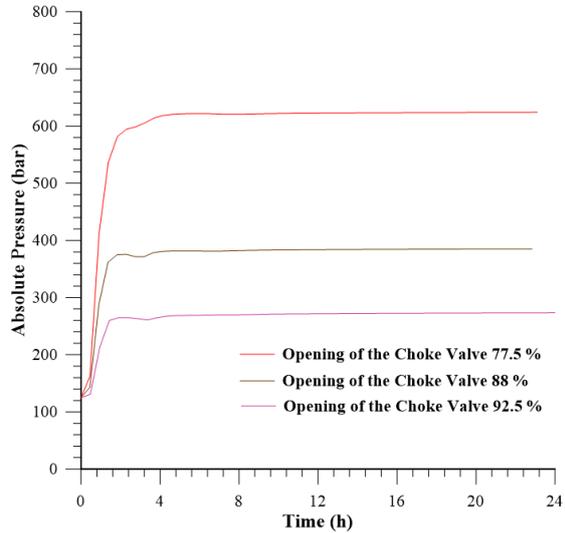Figure 14. Volumetric Oil Flow with Choke Valve - Riser (3140 m)

Figure 15. Absolute Riser Pressure with Choke Valve - Riser (3140 m)

As shown in Figure 16, for about the first 7 hours the flow pattern behavior was bubbly, changing to single-phase behavior after this period. This time of 7 hours is the same time that the oil volume flow needs to stabilize, according to Figure 14. The single-phase flow pattern plus the flow stabilization indicate that only one phase flows through the riser. This means that the gas is not trapped at the base of the riser and, consequently, the slug flow pattern does not occur. Figure 17 is a confirmation of the previous result, illustrating the resulting flow pattern along the length of the riser.
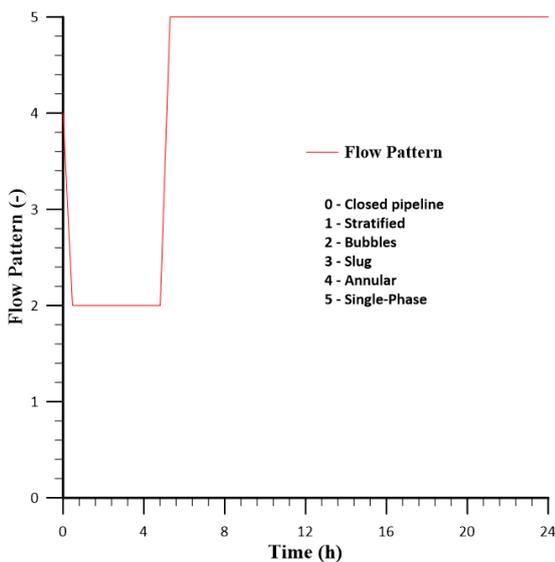

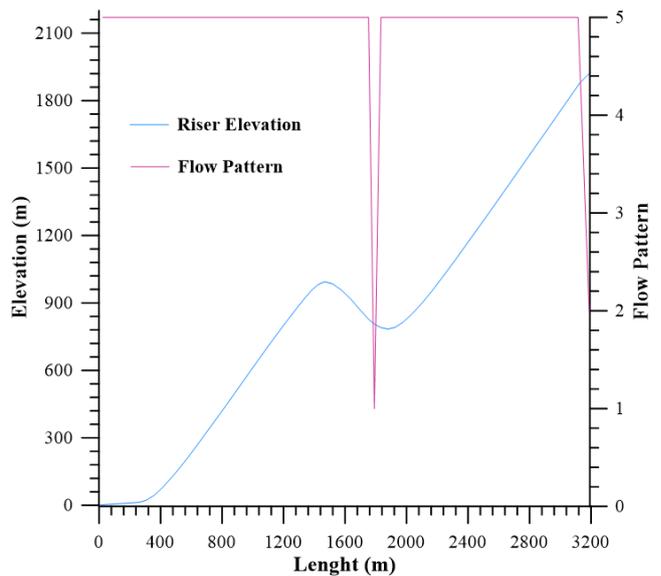Figure 16. Flow Pattern with 92.5 % Opening of Choke Valve Riser (3140 m)

Figure 17. Flow Pattern vs Elevation of Riser

According to Figure 18 the net holdup is approximately 0.85, which indicates that most of the fluid flowing through the riser is oil, confirming the result of the predominantly single-phase flow pattern as illustrated in Figures 16 and 17. The low presence of gas in the environment causes mitigation of the slug flow pattern, because the gas does not accumulate at the base of the riser.
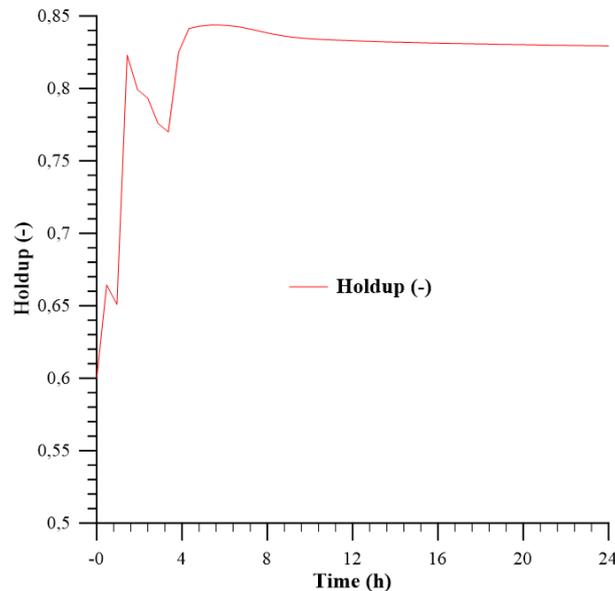
Figure 18. Holdup with 92.5 % Opening of Choke Valve - Riser (3140m)

6. CONCLUSIONS

The computer simulations performed in this work were developed with the aid of the ALFAsim multiphase single-dimension simulator, which allowed us to analyze the efficiency of ALFAsim in the representation of an offshore production system.

Through the results obtained, it was verified that the oil flow rate set at 1200 m³/d for the well-flowline-riser base case offered the system a slug flow pattern, since the volumetric flow rate behavior, throughout the oil production, exhibited peaks of high and low oil production.

The insertion of a choke valve on top of the riser, as a methodology to mitigate the occurrence of slugging, proved to be efficient in stabilizing the oil flow, offering a near-linear behavior after 7 hours of operational time in the computer simulation. All the proposed openings for the choke valve stabilized the oil flow, but the 92.5 % opening indicated it was to be more efficient than the others, since it presented the lowest back pressure in the system.

Furthermore, after 7 hours of operational time with the choke valve attached to the production system, the multiphase flow pattern changed to a predominantly single phase. The final result of the liquid holdup, close to 0.85, indicates that there is a predominant phase flowing in the medium, in this case, the oil phase. The gas does not become trapped at the base of the riser and consequently mitigating the phenomenon of slugging in this production system under study. Therefore, the efficiency of the insertion of a choke valve to control the slug flow pattern using the ALFAsim software can be verified, with satisfactory results.

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