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# Mitigation of Slug Formation in Pipeline-Riser Systems Using Bypass Lines: A Simulation-Based Approach

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***Abstract* - Slug formation in pipeline-riser systems has constituted a serious flow challenge that requires frequent evaluation to eliminate where possible. This work evaluates the volume flow at the riser top, fluid pressure at the outlet, accumulated and surge liquid volume flow, and riser base pressure for different bypass line sizes to attenuate slugging. A simulation-based approach was adopted, and a pipeline-riser model was developed, with a fluid characterization and property generation tool utilized for the fluid properties. A base case pipeline-riser model was created with a self-lift bypass line of internal diameter 6 inches for the pipeline to transport gas to the riser at a location above the riser base, connected to the start point at 2141.8186 ft. The bypass line transmits the pipeline gas to the riser at approximately 1/3 (90 ft) of the riser's total height from the base. A phase splitter node (start-up point) was placed at a distance of 2141.8186 ft along the pipeline between an internal node and a separator network. The phase splitter node was configured to allow only gas to pass through the "bypass line" and liquid through the "Subsea Tieback." Results show a stable liquid production of approximately 2861.35 bbl/day at the top side when an auxiliary bypass line of size 4 inches was used as a gas re-injection line into the riser column, whereas for the 2-inch, 6-inch, and 8-inch bypass lines, the total liquid flow was changing with time. There was a pressure build-up at the riser base, causing severe slugs to form and accumulate at the riser base, reaching the highest for the 2-inch bypass line size and the lowest for the 4-inch bypass line. An auxiliary self-lift bypass line of 4-inch size was the most effective in mitigating slugging in the pipeline system for the line sizes evaluated.**
***Keywords:* Slug Formation, Pipeline-Riser System, Bypass Line, Simulation-Based Approach, Pressure Build-Up**

## I. INTRODUCTION

Oil and gas production systems free of hindrance and blockage are vital to meet daily targets and expectations. Petroleum production engineers work to ensure an inexpensive, ecologically safe, and uninterrupted flow of oil and gas. A deviation from this would result in the loss of billions of dollars due to the time lost during cleaning and blockage removal. Slugging is one of the flow assurance issues facing production operators. Slugging is an alternating flow of oil and gas, characterized by variability in pressure and flow. This typically results in a multitude of operational challenges, including trips in the separator's topside and system shutdowns [1]. The hydrocarbon phases (crude oil and gas) in transit often exhibit flow regimes that lead to the development of slugs [2]. Liquid and gas phases are delivered alternately due to slugging, which causes interrupted flow. This delivery is induced by variations in the superficial velocities of the phases, which can result in liquid surges within the system. Slugging can occur in the horizontal portion of a pipe on the seafloor as well as in flexible riser systems [3].

A. H. Al-Kandari and V. S. Koleshwar discovered that flowlines with an inclined orientation and hydrocarbon content flowing upwards tend to facilitate slug flow. A buildup or obstruction of fluid within an inclined or vertical pipe or flowline (riser) at a low point results in severe slugging. This inclination is caused by pipeline geometry (typically a riser base dip) or topography [2].

Slug flow is common in two-phase flow engineering systems, such as oil and gas flowlines and process facilities [4], [5]. The establishment of a slug flow regime is naturally transitional, transforming from stratified to wavy flow and finally to slug flow [6]. Numerous laboratory and numerical studies have examined slug initiation and formation, as well as flow fluctuations in horizontal and inclined flow lines [7]-[9]. Existing measures to suppress this problem have either had limited applicability or adversely affected productivity [10]-[12]. Research has shown that no permanent solution to the problem of deepwater severe slugging exists, although many approaches have been proposed and tested without fully resolving the issue. It is also important to note that significant progress has been made in attenuating slug flow. However, literature shows that no single strategy provides superior performance. Research is thus oriented toward developing solutions to decrease slug flow while achieving stable flow and enhancing production systems.

Ø. Kaasa recommended a second riser linking the flowline to the platform to avoid significant slugging [13]. J. Hollenberg *et al.,* suggested a topside flow control method to reduce excessive slugging [14]. The search for slugging elimination has unveiled several unique methods, such as increasing back pressure, choking, gas lifting, and combinations of choking and gas lifting [15].

Among the suggested methods for slug attenuation is self-lift, but its applications have been largely laboratory-based, which do not adequately reflect real-world conditions. To reduce slug flow by breaking up the slugs of liquid in the riser column, J. Tengesdal *et al.,* devised the self-lift technique, also known as the slug mitigation strategy [16]. In this technique, gas is tapped from the upstream pipeline system through a bypass pipe to the riser column. Self-lift with adjustments in the inner diameter of the self-lift bypass and choke applications at the bypass was also studied, though the optimal size was not determined [17]. Slug flow was eliminated with consistent pressure using a 3-inch bypass line linked to the take-off point at the base of the riser along the pipeline using the self-lift technique [18].

Self-lifting has been widely recommended as a technique for alleviating slugging, but the implementation of bypass lines has not been effectively utilized. This study focused on a unique strategy for mitigating severe slugs using self-gas lifting and variations in the internal diameter of an auxiliary bypass line.

## II. METHODOLOGY

This section presents the numerical simulation approach for analyzing the optimum bypass line size for slug attenuation during self-lift mitigation. Multiflash and the OLGA simulator were used to develop a pipeline-riser model that transports produced fluids from the wellhead to the topside. Multiflash was utilized for phase behavior and properties modeling, as well as for the generation of the fluid file. Fluid composition was employed for phase behavior modeling, and the Peng-Robinson Equation of State was selected for the thermodynamic properties calculation. The model components were used to generate the PVT table file, which was then imported into OLGA for the pipeline-riser model and prediction of accumulated and surge liquid volume for different line sizes.

### *A. Input Data for Simulation*

Multiflash and OLGA, along with data on fluid properties (component composition, molecular weight, density, plus-fraction properties), pipeline and riser materials (material type, thermal conductivity, heat capacity, wall thickness, roughness, internal diameter), internal and outlet boundary conditions (flow rate, pressure, temperature), and heat transfer (ambient temperature, inner wall heat transfer coefficient), were used and are presented in Tables I to V. The workflow for the simulation in Multiflash and OLGA is presented in Figure 1.

TABLE I FLUID COMPOSITION

| Components | Mole % | Molecular Weight kg/kmol | Density (g/cm³) |
|---|---|---|---|
| CO2 | 0.54 | | |
| N2 | 0.69 | | |
| C1 | 54.85 | | |
| C2 | 4.85 | | |
| C3 | 2.23 | | |
| i-C4 | 2.15 | | |
| n-C4 | 2.44 | | |
| i-C5 | 2.56 | | |
| n-C5 | 5.31 | | |
| nC6 | 5.57 | | |
| C7+ | 18.81 | 350 | 870 |

TABLE II PROPERTIES OF THE PIPELINE MATERIALS (NEMOTO, *et al.,* 2010)

| Material | Density ($kg/m^3$) | Specific Heat (J/kg K) | Thermal Conductivity (W/m K) | Wall Thickness (mm) |
|---|---|---|---|---|
| Steel | 7850 | 500 | 50 | 8 |
| Insulation | 1000 | 1500 | 0.135 | 13.28 |

TABLE III PROFILE OF PIPELINE-RISER

| Pipe | X-Coordinate (ft) | Y-Coordinate (ft) | Diameter (in) | Wall Roughness (mm) |
|---|---|---|---|---|
| Pipeline start | 0 | -268.97 | 10 | 0.028 |
| Pipeline end | 2141.8186 | -269.485 | 10 | 0.028 |
| PS | 2141.8186 | -269.485 | - | - |
| Riser base | 4283.64 | -270 | 10 | 0.028 |
| Riser Top | 4283.64 | 30 | 10 | 0.028 |

TABLE IV HEAT TRANSFER DATA

| Property | Value |
|---|---|
| Pipeline overall heat transfer coefficient | $8W/m^2$-C |
| Riser overall heat transfer coefficient | $8W/m^2$-C |
| Ambient temperature | 6°C |

TABLE V INLET AND OUTLET BOUNDARY CONDITIONS

| Property | Value |
|---|---|
| Inlet mass flow rate | 5kg/s |
| Inlet temperature | 62°C |
| Outlet temperature | 22°C |
| Outlet pressure | 20bar |

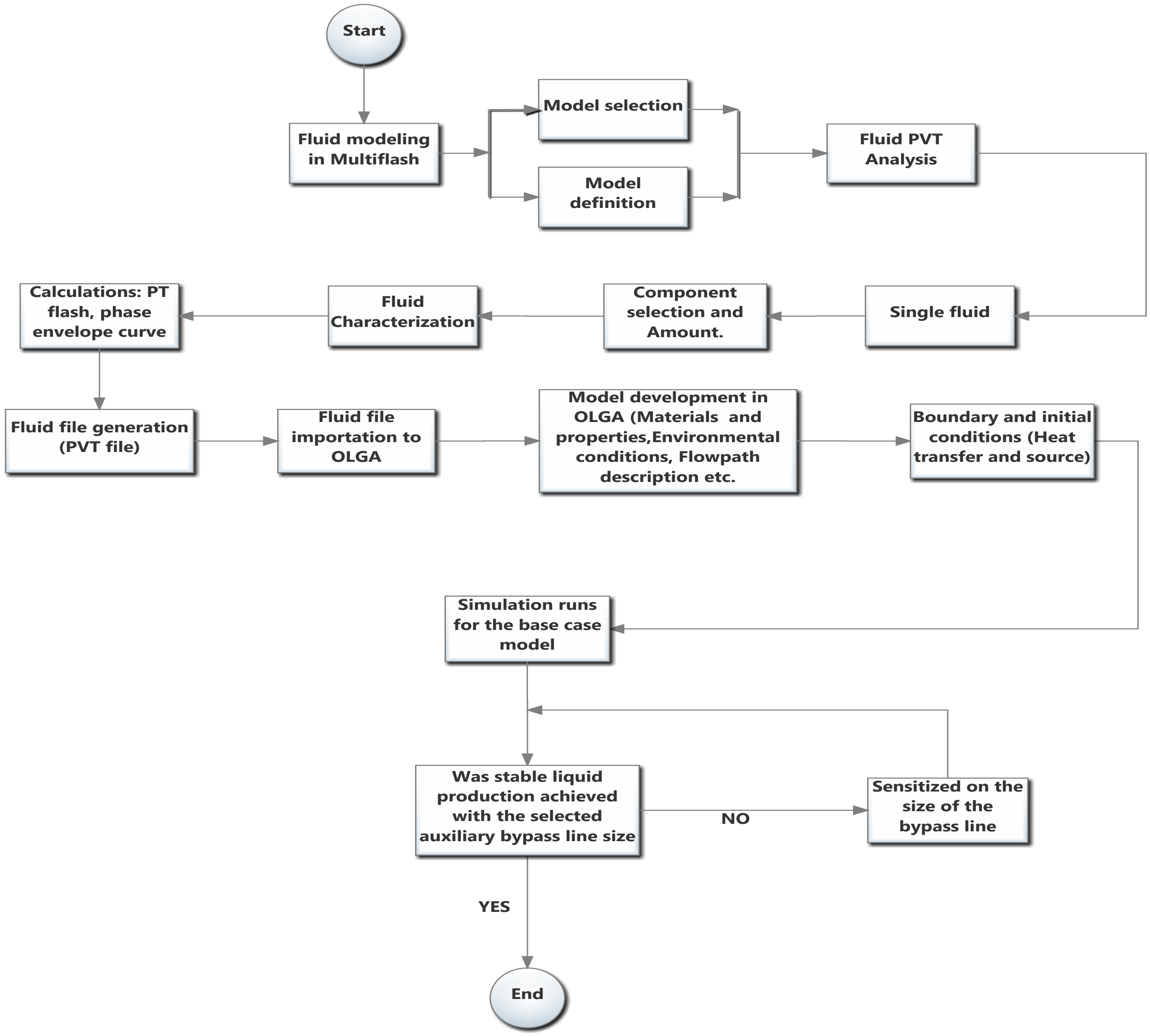


Fig. 1 Simulation workflow

The wellbore model development began with the setup of the model through the selection and definition of Multiflash. The fluid composition in Table 1 was entered and used as a basis for phase behavior modeling. The Peng Robinson (PR Advanced) EOS model was selected for the calculation of the thermodynamic properties (critical pressure and temperature, acentric factor, component fugacity) of the fluid compositional data. Each component of the composition was entered, and the C7+ component was created with a molecular weight of 350 kg/kmol and a specific gravity of 870 kg/m³, then characterized. These components were used to create the PVT table file for export to OLGA.

The generated PVT table file was imported into OLGA. A base case pipeline-riser model was established in OLGA, and the flow path with the nodes, which represent the input and output of the pipeline, were added. A bypass pipe was incorporated to carry the fluid from a predetermined point near the base of the riser. An auxiliary line was connected to the Subsea Tieback with the main riser. The pipeline-riser system consisted of a closed node at the start, followed by a mass source at the first section of the pipeline, a flow path, and an outlet node (which could be a separator) represented by a pressure node at the end. The materials and geometry data given in Tables II and III were used to define the pipeline-riser system.

The ambient conditions of the system, including the overall heat transfer coefficient from the system to the surroundings, were defined using the heat transfer data in Table IV. The fluid source was located at the first section of the pipeline. Data from Table V were used to set the inner and outer boundary conditions. A phase splitter node, which serves as the point of take-off along the line and functions between an inner node and a separator network, was placed at a distance of 2141.8186 ft along the pipeline. The phase splitter node was configured to allow only gas to pass through the bypass line and liquid through the Subsea Tieback. The bypass line transmitted the gas in the pipeline to the riser at approximately 1/3 (90 ft) of the riser's total height from the base and served as a re-injection point into the riser. The model was run for 2 hours to assess slug formation, total liquid volume flow, pipeline-riser outlet pressure, surge liquid volume, accumulated liquid volume, and the flow regime indicator. After evaluating the base case model, sensitivity analysis was conducted on the size of the self-lift bypass line. The self-lift OLGA model is shown in Figure 2.

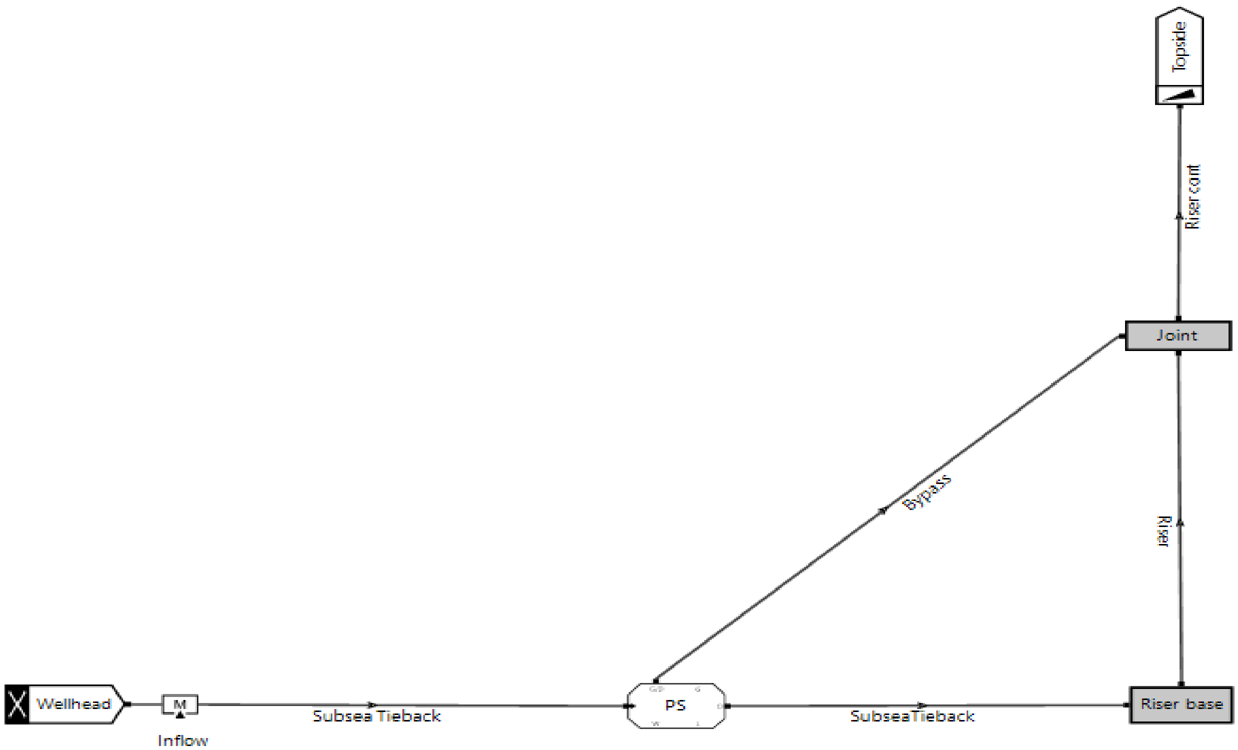


Fig. 2 Self-lift OLGA model

## III. RESULTS AND DISCUSSION

### *A. Total Liquid Volume Flow at the Riser Top*

The total liquid volume flow at the outlet of the pipeline-riser system is presented in Figure 3. A stable liquid production of 2861.35 bbl/day was obtained at the top side for an auxiliary 4-inch bypass line and gas re-injection line into the riser column. However, for the 2-inch, 6-inch, and 8-inch bypass lines, the total liquid flow fluctuated over time. For the 2-inch bypass line, the total liquid volume flow oscillated between 43,354.6 bbl/day at approximately 0.139987 hours and -5,001.62 bbl/day at approximately 1.91959 hours. For the 6-inch bypass line, the total liquid volume flow oscillated between 10,750.1 bbl/day at approximately 0.659709 hours and -8,454.95 bbl/day at approximately 0.099 hours. For the 8-inch bypass line, the total liquid volume flow oscillated between 36,605.2 bbl/day at approximately 1.30011 hours and -6,931.41 bbl/day at approximately 1.25988 hours. The short-length slugs that formed and dissipated intermittently confirm the cyclic fluctuations in total liquid volume flow in the column, indicating that the flow was not stable.

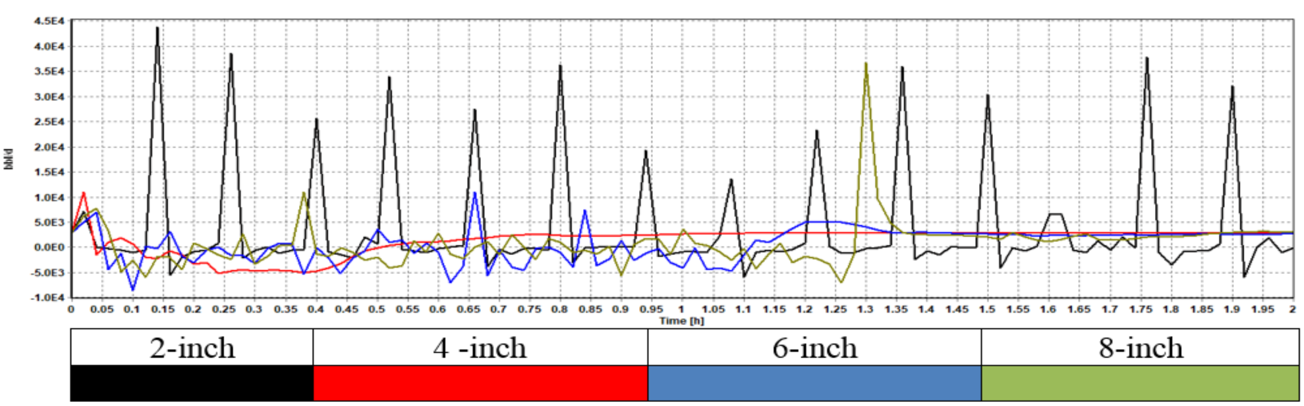


Fig. 3 Total liquid volume flow

*B. Fluid Pressure at Outlet*

The fluid pressure at the outlet of the system for 2-inch, 4-inch, 6-inch, and 8-inch auxiliary bypass line sizes is presented in Figure 4. There was stable fluid pressure of 292.822 psia at the riser top for the system with the 4-inch auxiliary bypass line, whereas for the systems with 2-inch, 6-inch, and 8-inch bypass line sizes, the fluid pressure fluctuated over time. The cyclic fluctuation of pressure at the riser top for the 2-inch, 6-inch, and 8-inch bypass lines indicates the presence of severe slugging. For the 2-inch bypass line, the fluid pressure fluctuated between 295.163 psia and 290.263 psia; for the 6-inch bypass line, the fluid pressure fluctuated between 290.365 psia and remained almost constant at 292.621 psia after 2 hours; and for the 8-inch bypass line, the fluid pressure fluctuated between 299.703 psia and 290.587 psia.

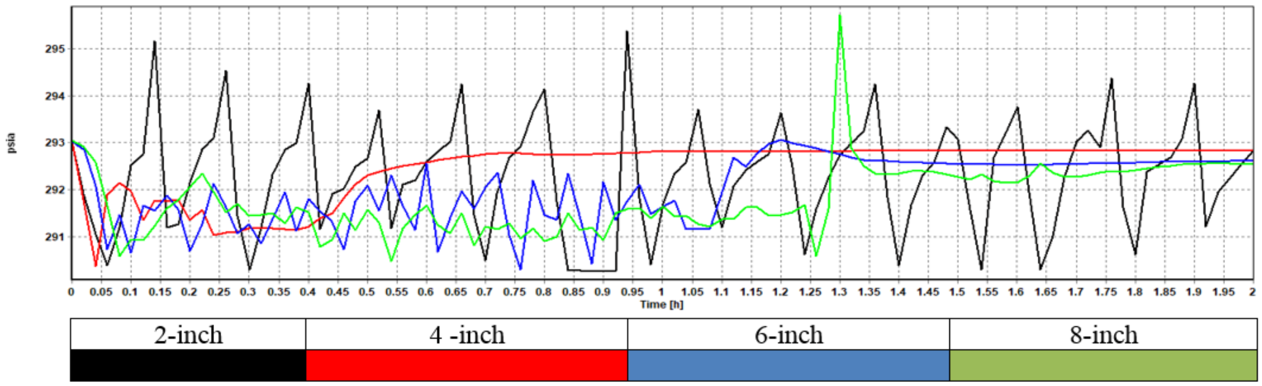


Fig. 4 Pressure at the outlet of the system

*C. Liquid Volume Flow Accumulated*

Figure 5 shows the accumulated liquid volume flow at the outlet of the system for 2-inch, 4-inch, 6-inch, and 8-inch auxiliary bypass line sizes. The accumulated liquid volumes were 228.992 bbl for the 2-inch line, 112.38 bbl for the 4-inch line, 59.1085 bbl for the 6-inch line, and 69.9564 bbl for the 8-inch line. A reduction in accumulated liquid volume was observed with increasing line size, as shown in Figure 6.

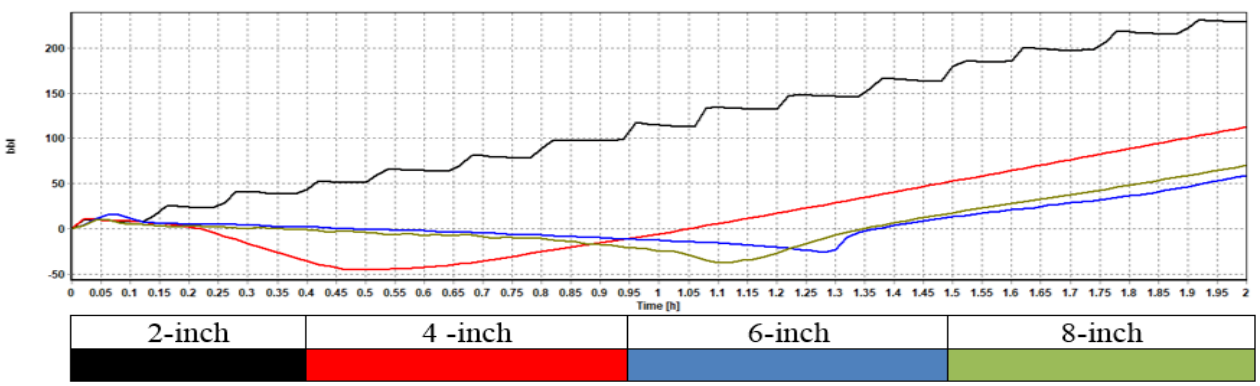


Fig. 5 Liquid volume flow accumulated at the outlet of the system

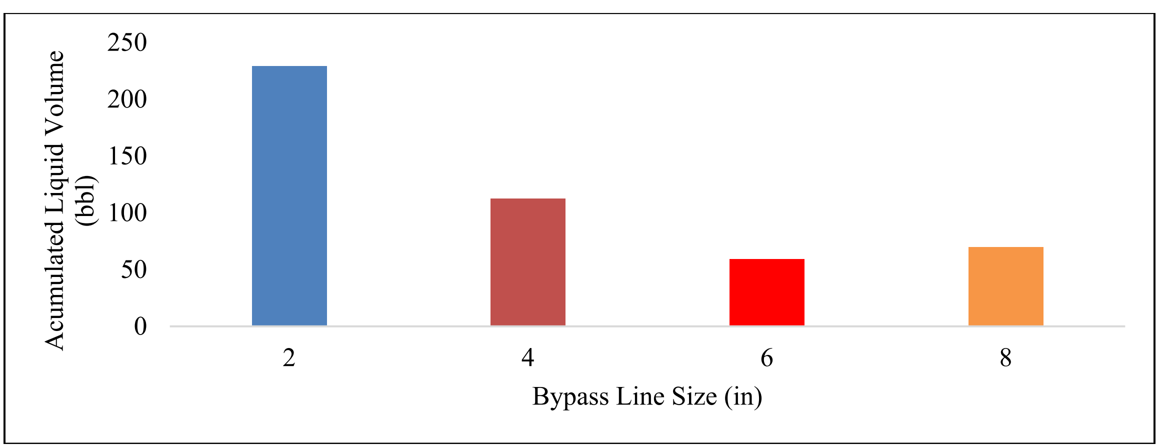


Fig. 6 Accumulated liquid volume for different Bypass line size

### *D. Surge Liquid Volume*

The surge liquid volume for 2-inch, 4-inch, 6-inch, and 8-inch auxiliary bypass lines is presented in Figure 7. After 2 hours, the model predicts a surge volume of 11.1811 bbl for the 2-inch bypass line, 76.5108 bbl for the 4-inch bypass line, 76.5882 bbl for the 6-inch bypass line, and 64.2465 bbl for the 8-inch bypass line. The maximum surge volume was 149.3610 bbl at an average maximum liquid drain rate of 0.178511 bbl/day for the 2-inch bypass line, 429.5756 bbl at an average maximum liquid drain rate of 0.08763 bbl/day for the 4-inch bypass line, 430.010 bbl at an average maximum liquid drain rate of 0.05455 bbl/day for the 6-inch bypass line, and 360.7166 bbl at an average maximum liquid drain rate of 0.04609 bbl/day for the 8-inch bypass line.

The surge liquid volume equates to accumulated liquid volume flow of 228.992 bbl for the 2-inch, 112.38 bbl for the 4-inch, 59.1085 bbl for the 6-inch, and 69.9564 bbl for the 8-inch auxiliary bypass line at the end of the pipeline when there is no drain at the pipeline end. A comparison of the bypass lines and their respective surge volumes is shown in Figure 8, with the 4-inch bypass line having the maximum surge volume.

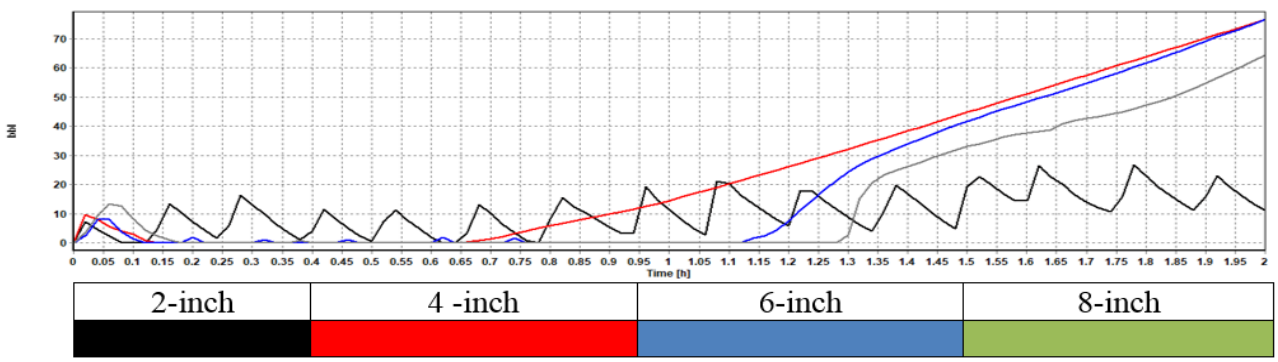


Fig. 7 Surge liquid volume

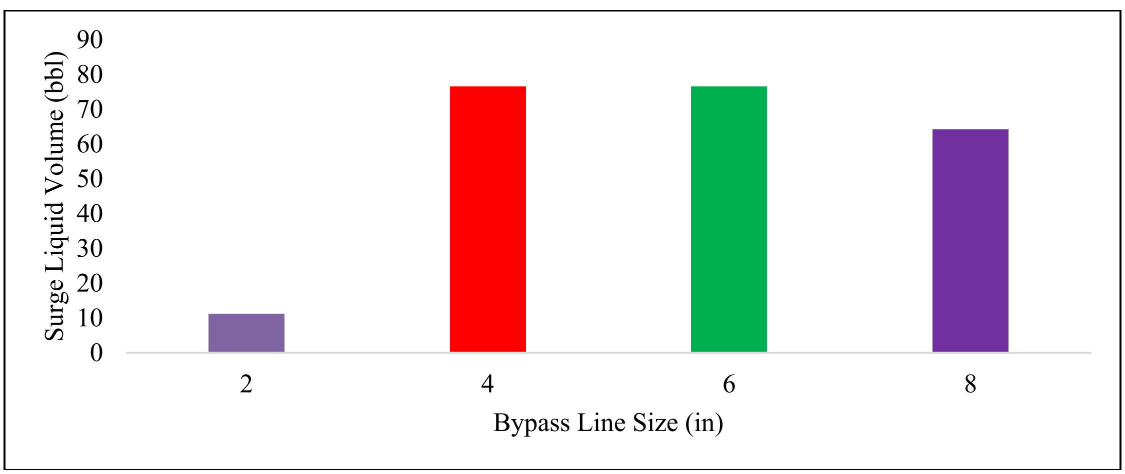


Fig. 8 Surge volume for different bypass line

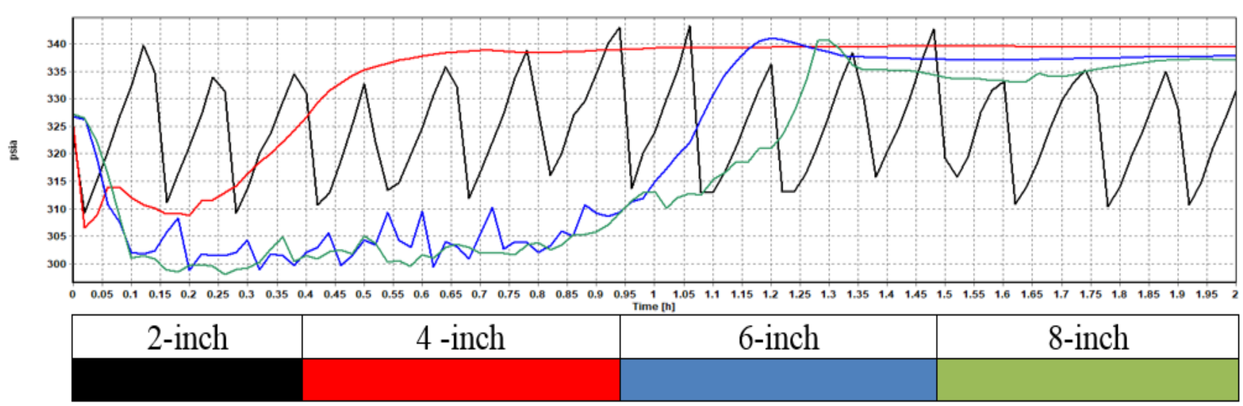


Fig. 9 Riser base pressure for all bypass line sizes

*E. Riser Base Pressure*

The variation in pressure at the base of the riser over time for 2-inch, 4-inch, 6-inch, and 8-inch auxiliary bypass lines is shown in Figure 9. The riser-base pressure increases as severe slugs accumulate at the base of the riser, reaching peak values of 346.325 psia for the 2-inch bypass line, 339.455 psia for the 4-inch bypass line, 342.893 psia for the 6-inch bypass line, and 341.968 psia for the 8-inch bypass line. The riser-base pressure exhibited a recurring pattern for the 2-inch line, while for the 6-inch and 8-inch lines, it was almost constant at certain times. For the 4-inch bypass line, the riser-base pressure built up to a steady value of 339.455 psia, implying a reduction or elimination of severe slugs at the riser base.

## IV. CONCLUSION

In this work, the impact of bypass line sizes on hydrodynamic slug flow for slug attenuation using a self-lifting approach was analyzed. A numerical simulation approach was adopted to examine the optimum bypass line size that would reduce or eliminate slugging. A base case pipeline-riser model was created with a self-lift bypass line with an internal diameter of 6 inches for transferring gas to the riser at a predetermined point up the base of the riser, connected to the take-off point. Sensitivity analysis was conducted for bypass line sizes both below and above the base case. Stable liquid production at the top side was observed with an auxiliary bypass line of size 4 inches. An increase in bypass line size decreases the accumulated liquid volume flow. The 4-inch bypass line size exhibited stable flow and was the most effective in attenuating slugging among the line sizes evaluated.

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