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Evaluating the Effect of Changing Tubing Sizes on Pressure Traverses and Flow Regime along the Wellbore

Isaac Eze Ihua-Maduenyi1, Robin Nyemenim Abu2, Victoria Akuchukwu Umejuru3

1Department of Petroleum Engineering, Rivers State University, Port Harcourt, Nigeria
Isaac.ihua-maduenyi@ust.edu.ng
2Department of Petroleum Engineering, Rivers State University, Port Harcourt, Nigeria
3Department of Petroleum Engineering, Rivers State University, Port Harcourt, Nigeria

Abstract*— Changing tubing sizes on pressure traverses and flow regime along the wellbore emphasizes the need for precise tubing size selection to ensure efficient production and wellbore stability, advocating for the use of simulation tools to optimize well design. This study evaluates the effect of tubing size on pressure traverses and flow regimes along the wellbore using simulations conducted with PROSPER well modeling software. The research highlights the significant role that tubing size plays in oil and gas production, influencing pressure distribution and flow characteristics such as laminar, turbulent, or transitional flow regimes. The results for the pressure traverses, shows that as tubing size increases, the bottomhole flowing pressure decreases. For example, at a wellhead pressure of 250psig, tubing sizes of 2.441 inches to 4.052 inches resulted in bottomhole pressures ranging from 1210.86psig to 595.08psig. It also for flow regimes, reveals that the well's operating point often falls within the annular flow regime for tubing sizes 2.441, 2.992, and 3.458 inches, but in the bubble flow regime for the 4.052-inch tubing. The flow regime map analysis showed that smaller tubing sizes tend to reduce liquid loading tendencies, whereas larger tubing sizes may cause gas slippage and complicate operations. Again, the results suggest that selecting the appropriate tubing size is crucial for optimizing well production rates, minimizing pressure losses, and reducing the risk of operational inefficiencies.*

Keywords— Tubing Sizes, Pressure Traverses, Flow Regime, Wellbore

1. INTRODUCTION

In the oil and gas industry, the extraction of hydrocarbons from subsurface reservoirs involves the intricate design and operation of wellbores. The efficiency and safety of these operations are highly dependent on understanding the fluid dynamics within the wellbore. One critical aspect of this is the pressure traverse, or the variation of pressure along the wellbore length, and the flow regime, which can be laminar, turbulent, or transitional. These factors are significantly influenced by the size of the tubing used in the wellbore. Tubing size plays a vital role in determining the flow characteristics and pressure distribution in a wellbore [1]. The internal diameter of the tubing affects the velocity profile of the fluid, the frictional pressure losses, and the overall flow regime [7]. Selecting an appropriate tubing size is essential to optimize production rates, ensure operational stability, and maintain the integrity of the wellbore. Incorrect tubing size can lead to increased pressure drops, inefficient fluid flow, and potentially hazardous conditions [2].

Historically, the selection of tubing sizes was largely empirical, based on field experience and trial-and-error methods [1]. Early engineers relied on simple calculations and rules of thumb to choose tubing sizes that would balance production rates with operational constraints [7]. While these methods provided a basic understanding, they lacked the precision needed for optimizing wellbore design in varying conditions. With the advent of computational fluid dynamics (CFD) and other advanced simulation tools, it has become possible to model wellbore conditions with a high degree of accuracy. CFD allows engineers to simulate the behavior of fluids within the wellbore, considering factors such as fluid properties, wellbore geometry, and operational conditions [2]. These simulations provide detailed insights into how changes in tubing size affect pressure traverses and flow regimes [7]. By conducting detailed simulations and analyses, this will help bridge the gap between theoretical models and real-world applications, offering a more comprehensive understanding of wellbore fluid dynamics.

Once a well has been drilled and completed, the reservoir fluid can be produced through the casing, tubing or both. Mostly, wells are produced through the tubing in order to isolate the casing from corrosion and for use of artificial lift system [6], [5]. It became essential that for any selected production tubing size, the well should flow naturally. Choosing an undersized tubing will result in excessive flow velocity and hence increased friction resistance in the well which limits the well production rate. The undersized tubing may as well restrict the type and size of artificial lift equipment [4]. Using oversized tubing on the other hand would result in low flow velocity and hence excessive liquid loss due to gas slippage effect. Large tubing size would also complicate workover operations due to loading of the well resulting from heading and unstable flow [4]. According to [10], the need to select the optimum tubing size that ensures an optimum state for the friction resistance and liquid-phase loss due to gas slippage which in turn would ensure the longest flowing time and lowest lifting energy consumption was emphasized. Tubing size also plays a crucial role in well performance, determining the fluid flow capacity through the wellbore. Larger tubing allows for higher production rates but can be costlier and more challenging to install. For optimal production rates, it's essential to match the tubing size with well requirements. Undersized tubing increases pressure drop, limiting production, while oversized tubing causes slippage, where different fluid phases move at varying velocities [3]. Traditionally, the rationalize for designing hole structure and selecting production casing sizes is determined by the drilling engineer, followed by well completion operation to determine tubing size [9], [10]. The rational tubing size can be chosen using sensitivity analysis based on nodal analysis during the flowing production stage. Unfortunately, many current reservoir simulators do not account for well completion details [11]. According to [8], there exists a disconnect between reservoir simulators and wellbore hydraulics prediction software concerning complex well hydraulics and completion design effects.

The design and operational efficiency of oil and gas wells are heavily influenced by the fluid dynamics within the wellbore. One critical factor in these dynamics is the size of the tubing used to transport fluids from the reservoir to the surface. Despite the significance of tubing size, there is a lack of comprehensive studies that systematically evaluate how varying tubing sizes affect pressure traverses and flow regimes. This gap in knowledge can lead to suboptimal wellbore designs, inefficiencies in hydrocarbon production, and increased operational risks. This work used POSPER to systematically evaluate the effects of changing tubing sizes on pressure traverses and flow regimes along the wellbore.

2. MATERIALS AND METHODS

2.1 Materials

PROSPER well modelling software and literature are the materials used in this study. The literature data consisted of fluid properties (solution gas/oil ratio, gas and oil gravity, water salinity), deviation survey and geothermal gradient data (measured depth against true vertical depth, formation temperature against depth and overall heat transfer coefficient), downhole equipment data (casing and tubing setting depth, internal diameter and wall thickness). These data are presented in Table 1 – 5.

Table 1: Model configuration option

Property	Specification
Fluid type	Oil and Water
Fluid properties calculation method	Black Oil
Separator type	Single-Stage Separator
Well completion type	Cased hole
Flow type	Single branch
Well type	Producer

Table 2: Fluid properties data

Property	Value
Solution GOR	800 SCF/STB
Gas Gravity	0.58
Water salinity	75000 ppm
Oil gravity	38°API
Mole % H_2S	0%
Mole % CO_2	0%
Mole % N_2	0%

Table 3: Deviation survey data

Measured Depth True Vertical Depth	Measured Depth True Vertical Depth
0	0
1000	1000
2000	2000

Table 4: Downhole equipment data

	Measured Depth (ft)	Inside Diameter (ft)	Roughness (ft)
Xmas	0	-	-
Tubing	1800	2.992	0.0006
Casing	2000	6.4	0.0006

Table 5: Geothermal gradient data

Measured Depth	Temperature
0	80
2000	120

2.1 Methods

The fluid type, flow type, well completion type, heat transfer calculations etc., were selected using the data in Table 1 to configure the model. The fluid properties data shown in Table 2 were entered in the PVT input section. The wellbore configuration was described with the deviation survey data presented in Table 3.

The deviation survey is the reference for all subsequent depth inputs for downhole equipment data entry. The downhole equipment section defines the path through which the fluid will flow as it is produced up the well bore. Details of the downhole equipment installed are shown in the Table 4.

Geothermal gradient data shown in Table 5 were populated in the temperature input interface and an Overall Heat Transfer Coefficient (OHTC) value of 8-Btu/h/ft^2/°F was also entered to account for the heat transfer from the fluid to the surroundings. Pressure traverse calculations were carried out at a wellhead pressure of 250psig, liquid rate of 7500 STB/day and water cut of 50% for tubing sizes of 2.441-in, 2.992-in, 3.458-in and 4.052-in respectively.

2.2 Simulation workflow

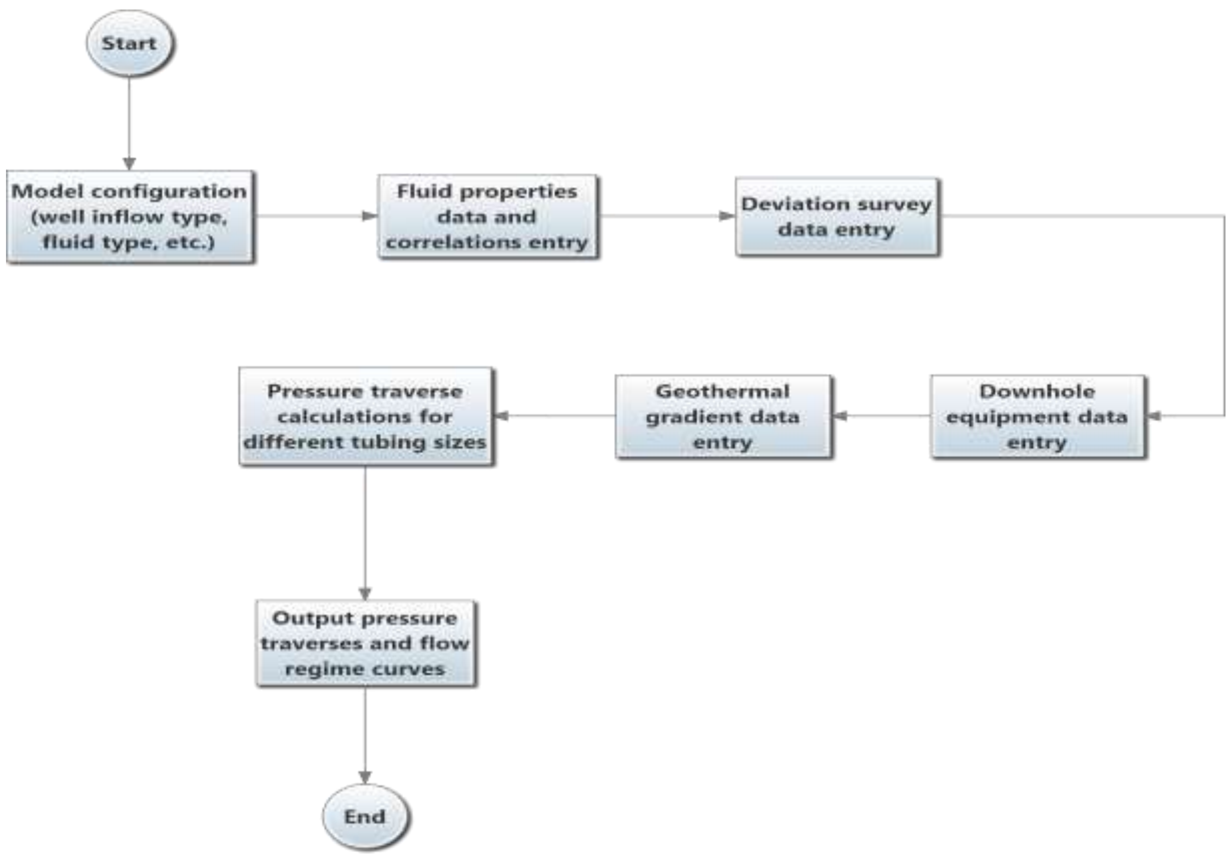

Figure 1: Simulation workflow

2. Results and Discussion

3.1 Pressure Traverse at 250psig Wellhead Pressure

Figure 2 shows the pressure traverses along the wellbore at a wellhead pressure of 250psig for tubing sizes of 2.441-in, 2.992-in, 3.458-in and 4.052-in respectively. Results indicated an increase in the pressure traverses along the wellbore. For a tubing size of 2.441-in, 2.992-in, 3.458-in and 4.052-in, result gave a bottomhole flowing pressure of 1210.86psig, 841.02psig, 689.96psig, and 595.08psig respectively.

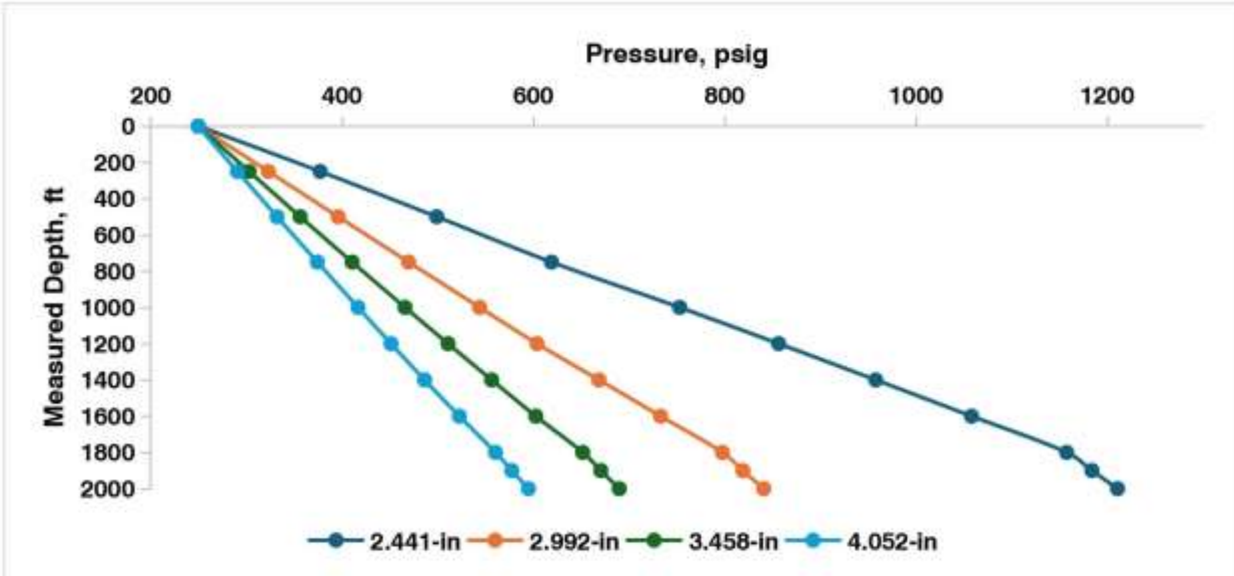

Figure 2: Measured depth against pressure at 250psig wellhead pressure

3.2 Pressure Traverse at 500psig Wellhead Pressure

Figure 3 shows the pressure traverses along the wellbore at a wellhead pressure of 500psig for tubing sizes of 2.441-in, 2.992-in, 3.458-in and 4.052-in respectively. Results indicated an increase in the pressure traverses along the wellbore. For a tubing size of 2.441-in, 2.992-in3.458-in and 4.052-in, result gave a bottomhole flowing pressure of 1463.41psig, 1132.28psig, 1002.68psig, and 932.83psig respectively.

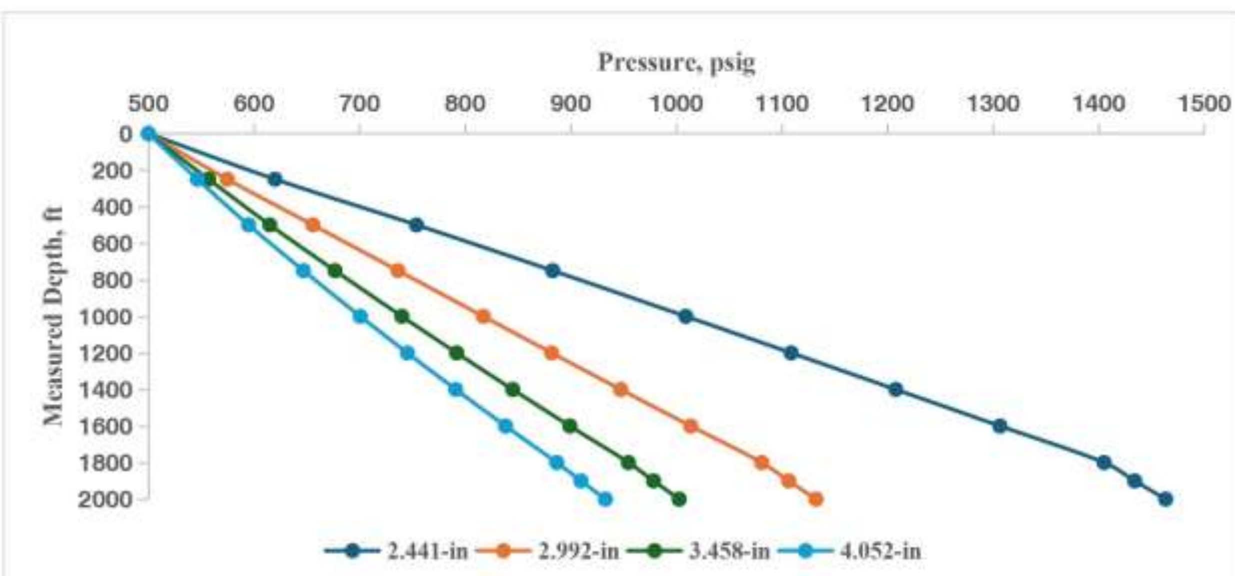

Figure 3: Measured depth against pressure at 500psig wellhead pressure

3.3 Pressure Traverse at 750psig Wellhead Pressure

Figure 4 shows the pressure traverses along the wellbore at a wellhead pressure of 750psig for tubing sizes of 2.441-in, 2.992-in, 3.458-in and 4.052-in respectively. Results indicated an increase in the pressure traverses along the wellbore. For a tubing size of 2.441-in, 2.992-in, 3.458-in and 4.052-in, result gave a bottomhole flowing pressure of 1711.16psig, 1414.25psig, 1317.2psig, and 1265.46psig respectively.

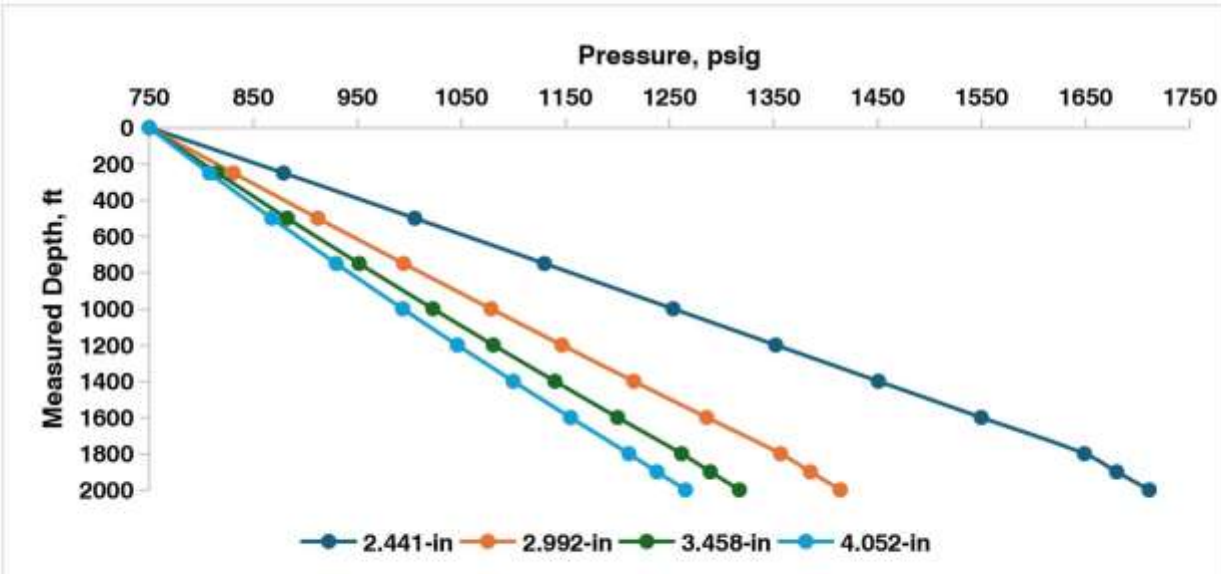

Figure 4: Measured depth against pressure at 750psig wellhead pressure

3.4 Pressure Traverse at 1000psig Wellhead Pressure

Figure 5 shows the pressure traverses along the wellbore with a wellhead pressure of 1000psig for tubing sizes of 2.441-in, 2.992-in, 3.458-in and 4.052-in respectively. Results indicated an increase in the pressure traverses along the wellbore. For a tubing size of 2.441-in, 2.992-in, 3.458-in and 4.052-in, result gave a bottomhole flowing pressure of 1958.7psig, 1699.8psig, 1619.52psig, and 1577.33psig respectively.

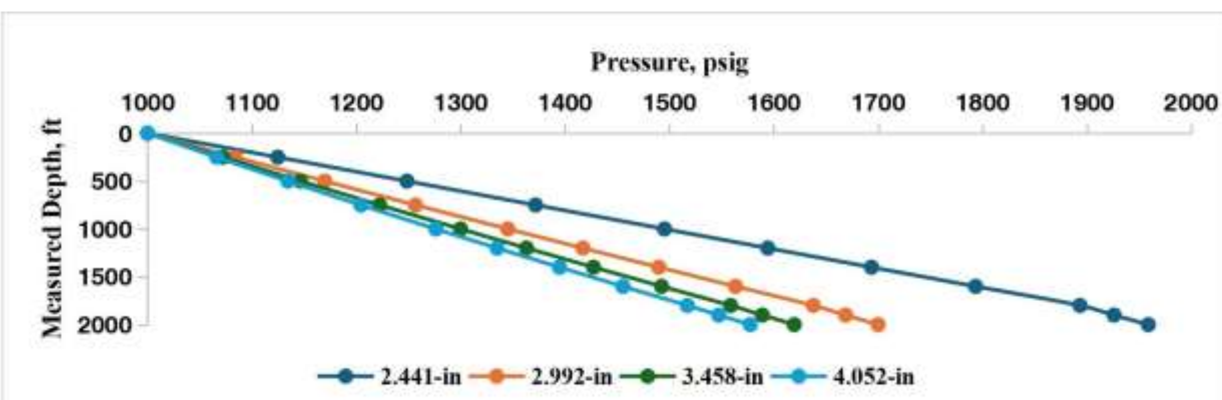

Figure 5: Measured depth against pressure at 1000psig wellhead pressure

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3.5 Flow Regime Map in Tubing of 2.441-in

The flow regime map for a well with a tubing size of 2.441-in is shown in Figure 6. Result shows that the operating point of the well (flow rate) was within the annular flow regime boundary. Consequently, for a tubing size of 2.441-in, result gave a superficial gas velocity of 1.290ft/s and a superficial liquid velocity of 1.189ft/s.

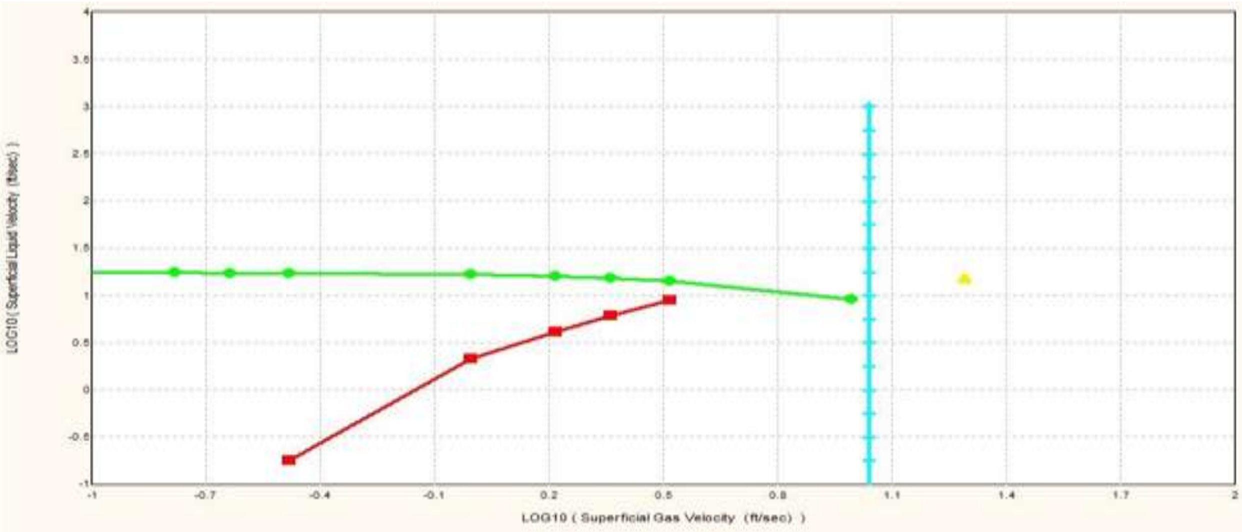

Figure 6: Superficial gas velocity against superficial liquid velocity for 2.441-in tubing

3.6 Flow Regime Map in Tubing of 2.992-in

The flow regime map for a well with a tubing size of 2.992-in is shown in Figure 7. Result shows that the operating point of the well (flow rate) was within the annular flow regime boundary. Consequently, for a tubing size of 2.992-in, result gave a superficial gas velocity of 1.206ft/s and a superficial liquid velocity of 1.011ft/s.

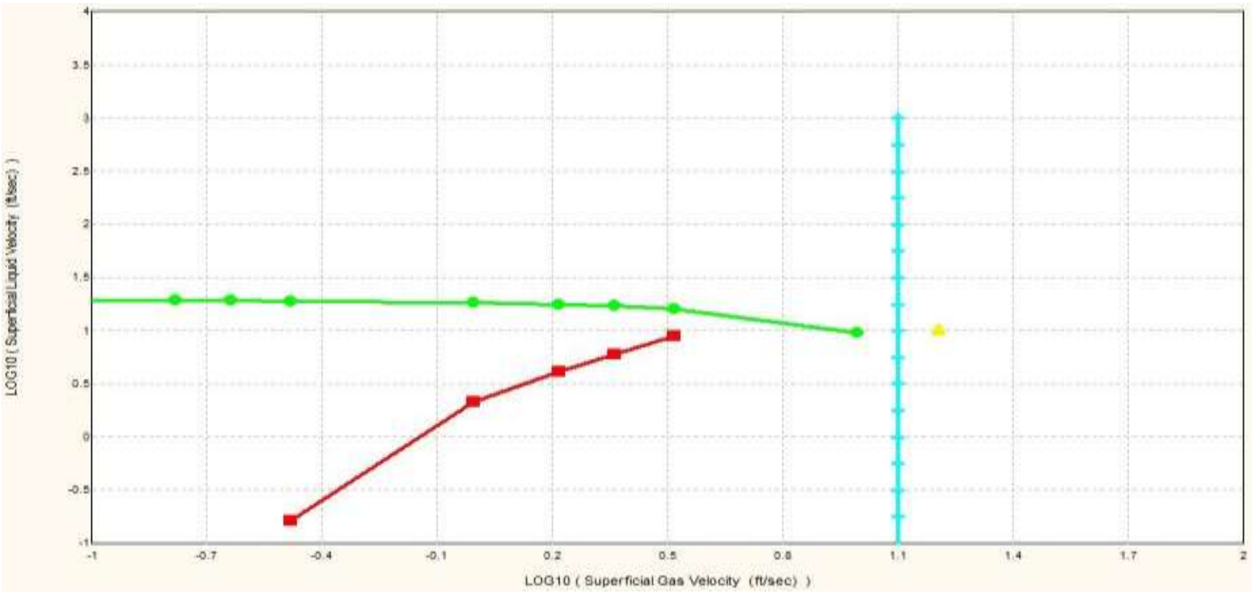

Figure 7: Superficial gas velocity against superficial liquid velocity for 2.441-in tubing

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3.7 Flow Regime Map in Tubing of 3.458-in

The flow regime map for a well with a tubing size of 3.458-in is shown in Figure 8. Result shows that the operating point of the well (flow rate) was within the annular flow regime boundary. Consequently, for a tubing size of 3.458-in, result gave a superficial gas velocity of 1.277ft/s and a superficial liquid velocity of 0.884ft/s.

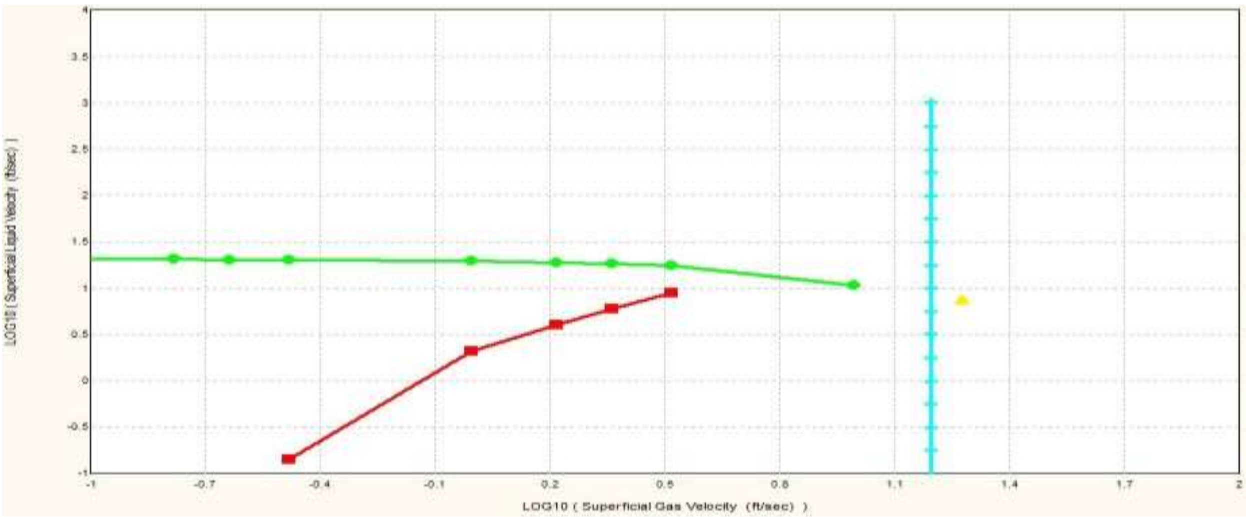

Figure 8: Superficial gas velocity against superficial liquid velocity for 3.458-in tubing

3.8 Flow Regime Map in Tubing of 4.052-in

The flow regime map for a well with a tubing size of 4.052-in is shown in Figure 9. Result shows that the operating point of the well (flow rate) was within the bubble flow regime boundary. Results further reveals that for a tubing size of 4.052-in, result gave a superficial gas velocity of 1.178ft/s and a superficial liquid velocity of 0.746ft/s.

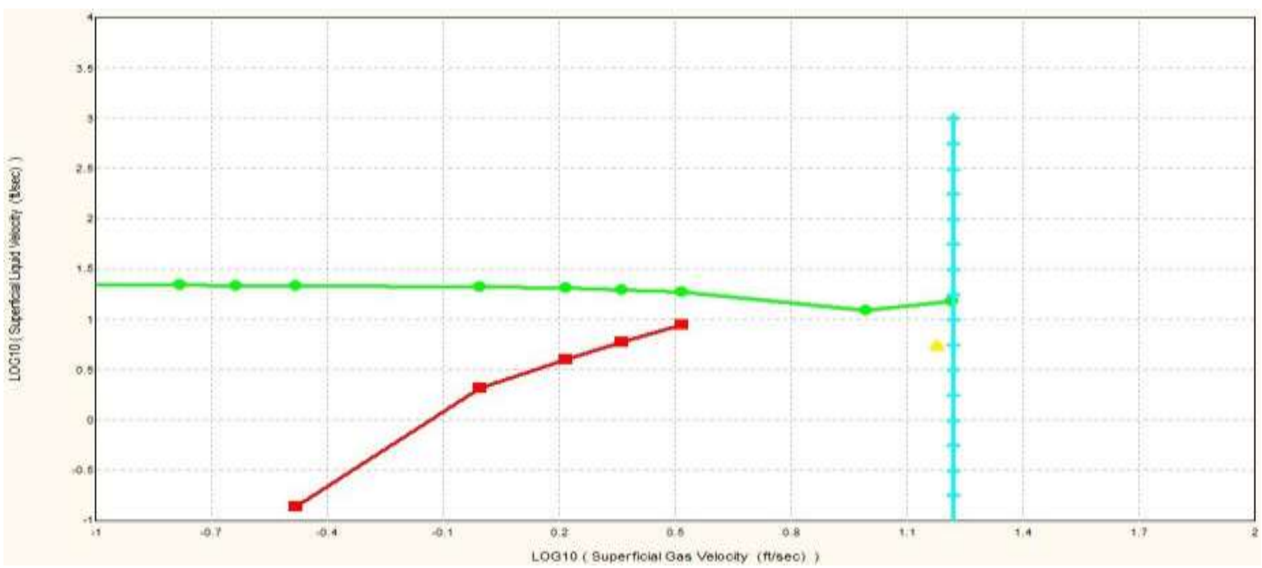

Figure 9: Superficial gas velocity against superficial liquid velocity for 4.052-in tubing

3. Conclusion

This work investigated the effects of changing tubing sizes on pressure traverses and flow regime along the wellbore. A simulation based approach was adopted and PROSPER was used for the model development. The findings indicate that changing tubing sizes alter pressure traverses, influence wellbore performance, and smaller tubing sizes reduce liquid loading tendency. Additionally, the work shows that annular flow configuration outperforms tubing flow in terms of production rate, and optimal tubing size selection is crucial for minimizing pressure losses.

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