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Investigating the Impact of tubing size and Flow Regimes on Liquid Loading for Efficient Gas Well Production

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Abstract
The lowest gas rate for unloading liquid from a gas well has been a subject for research for many years now, most especially for reservoirs with rapid declining pressure. In producing gas wells with low reservoir pressure, the accumulation of liquids can lead to early well abandonment. Different correlations have been developed to handle the issue of liquid loading through the prediction of the gas well critical rate for unloading. In this work, gas wells were simulated to ascertain the impact of tubing sizes and flow regimes on liquid loading. Using 2.441, 2.992, 3.476 and 3.598 inch tubing sizes, the flow regimes were ascertained while monitoring the liquid content in the wellbore. PIPESIM was used to simulated the well conditions while OLGA was used to develop the flow regime map and velocity profiles of the well through the principle of Nodal Analysis. It was discovered that with 2.441 and 2.992 tubing sizes, the well-produced with annular flow but below the critical flow rate and thus could not guarantees gas flow without liquid accumulation while 3.476 and 3.598 inch tubings produced above the critical flow rate but have slugging, which could exacerbate loading. In order to ensure gas production without liquids at the onset, the interfacial tension was modified to 0.000056N/m. With this modification, the flow regime for 3.476 changed to annular, bubble and slug flows with annular flow as the predominant flow regime. Thus, 3.476 in tubing was selected as the optimum tubing size based on its ability to guarantee high flow rate, lower erosional velocity and lower cost.

Keywords: *Flow regimes, Liquid loading, Tubing sizes, Critical velocity, Nodal analysis*

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1. Introduction

Liquid loading is one of the most common issues during gas production where liquids are co-produced with the gas in the form of condensates or water. The condensates could be naturally occurring and produced along with the gas or induced as a result of thermodynamic alterations in the wellbore (Neves and Brim-hall 1989). Over 90% of gas wells in the world are susceptible to the menace of liquid loading (Veeken et al., 2003). Gas wells load liquids when the gas velocity is not sufficient enough to lift produced liquids to the surface thus resulting to flow reversal. Liquid loading is inevitable but could be managed effectively and its concurrence is an indication of a deteriorating gas-liquid two-phase flow or multiphase phenomenon (Joseph and Hicks, 2018). The continuous deterioration of the flow conditions could give rise to multiple flow regimes that would compound the effective management of gas wells.

Moreover, this liquid when built up in the wellbore imposes a back pressure on the adjacent formation that could eventually kill a well if no adequate mitigation measures are in place. Unfortunately, the onset and occurrence of liquid loading is not easily masked and some notable symptoms of its occurrence include (Sankar and Karthi, 2019; Lea and Nickens., 2004):

a. Metastable production and rise in decline rate
b. Drop in Tubing Pressure with Rise in Casing Pressure
c. Abrupt cessation of liquid production
d. Sudden increase in the liquid content in the wellbore
e. Large amount of slugs observed at the surface and

f. Sudden decline in the amount of gas being produced.

Basically, two methods are in place for effectively managing liquid loading in gas wells: the curative and preventive methods. The predictive techniques are also preventive methods that forecasts when loading would likely happen in gas well and provide guide to help prevent loading of wells. A very renowned predictive method by Turner et al (1969) is the Entrained Droplet model for estimating the critical velocity given as:

$$v_c = 1.912\frac{\sigma^{\frac{1}{4}}(\rho_l-\rho_g)^{1/4}}{\rho_g{}^{1/2}} \quad (1)$$

where: v_c = Critical velocity, (ft/sec), σ = Surface tension, (dynes/cm), ρ_l = Liquid density, (lbm/ft^3), ρ_g = Gas density, (lbm/ft^3). Gas wells flowing above the critical velocity have the tendency of unloading any liquid droplets entrained in the core of gas wells while wells flowing below the critical velocity are prone to liquid loading. Coleman et al. (1991) also developed a variant but identical model to Turner et al (1991) for the critical velocity of condensates and water as the loading fluids given as:

$$v_g(condensate) = \frac{4.02(45-0.0031P)^{1/4}}{(0.0031P)^{1/2}} \quad (2)$$

$$v_g(water) = \frac{5.62(67-0.0031P)^{1/4}}{(0.0031P)^{1/2}} \quad (3)$$

And the critical flow rate as

$$q_c = \frac{3.06PV_gA}{Tz} \quad (4)$$

where P is the pressure (psia), v_g is the critical velocity (ft/s),

Q_c = critical rate, A is area (ft^2), T is the temperature (°R) and z is the gas deviation factor. Considering possible deformation of a free falling liquid droplet, Li et. al. (2002) developed a correlation that incorporates the changes on a free falling liquid droplet when it undergoes a deformation from a spherical to a convex beam shape with unequal sides as:

$$v_c = 2.5\frac{\sigma^{\frac{1}{4}}(\rho_l-\rho_g)^{1/4}}{\rho_g{}^{1/2}}\ (f/s) \quad (9)$$

where: σ= Interfacial tension, ρ_l= Liquid density and ρ_g= Gas density

The curative methods are measure deployed when a well is already loaded. They are used to unload gas wells and the particular type chosen at a given time is dependent on the economics, ease of application, severity of the problem and the accessibility. Typical examples in this category are: the gas lift method (Veeken et al, 2003; Dinata et al. 2016), plunger lift method (Lea and Nickens, 2004), velocity string (Arachman et al, 2004) and pumps.

Although, both the curative and preventive methods have brought significant relief in the industry for effectively managing liquid loading in gas wells, they have not brought an absolute solution in tackling this menace. This is because the root cause of the likely problems that trigger the condensation and subsequent accumulation of liquids is not addressed by both methods. Thus, in this study an attempt is made to investigate the effects of tubing sizes using OLGA and PIPESIM simulation software. It is believed that selecting the optimum tubing size and accurately predicting the in situ flow regime could help to effectively control the rate of liquid accumulation and thus, prolong the lifespan of gas wells.

2. Materials and methods

Basically, the principle of analysis used is the Nodal analysis method. The data used for this simulation were obtained from a well in a Niger Delta field and it includes the gas composition of the well, the temperature and pressure of the stream, fluid properties and the well geometry. The gas composition is given in Table 1 while other fluid and well properties are given in Table 2. The schematic of the simulated well using PIPESIM is shown in Figure 1. Both PIPESIM and OLGA Multiphase flow simulators were used in this analysis. PIPESIM was used to simulate the well while OLGA was used to simulate the flow regimes and velocity profiles of the well.

Table 1: Composition of the gas stream used for the simulations

Components	Mole fraction (%)
Methane	78
Ethane	8
Propane	3.6
Isobutane	1.5
Butane	1.5

Isopentane	0.7
Pentane	0.5
Hexane	0.5
C7+	6
Total	100

The Turner et al. (1969) model was used as the default correlation in investigating the effects of tubing size and flow regimes on liquid loading in the software. To avoid liquid loading of a well at the onset of the simulation, the liquid in the tubing is constrained to be in the annular-mist flow regime. In this flow regime, the gas velocity is higher than the critical velocity or the settling velocity of liquid droplets, and thus will force the liquid in the tubing out of the well. In selecting a tubing size, the following factors were considered:

1. The tubing should be able to give high flowrate
2. Its erosional velocity must be less than 1
3. And finally, the economics. It should not be too expensive to accommodate the desired optimum flow rate or potential.

Table 2: Well and fluid parameter used for the simulations

Parameter	Value	Unit
Pressure	4600	psia
Temperature	280	F
Wall roughness	0.004	m
Tubing Angle of inclination	89.94	degree
Tubing diameters	2.441, 2.992, 3.476, 3.598	in
Superficial gas velocity	1.24	m
Superficial liquid velocity	0.808	m
Gas density	45.49	kg/m^3
Liquid density	906.65	kg/m^3
Gas viscosity	$1.8*10^{-5}$	$N\text{-}S/m^2$
Surface tension	0.03, 5	N/m

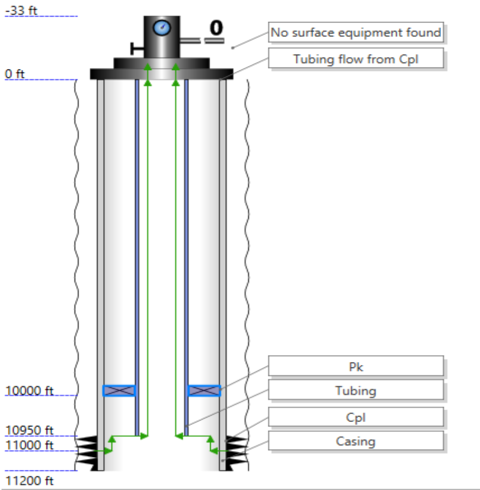


Fig. 1: Schematics of simulated well using Pipesim

The well deliverability was simulated by selecting the single branch model, vertical completion. and specifying the tubing size to be used in the well. The well operating point was specified, and the reservoir and tubing data were imputed to run the simulation for calibration. Some parameters were tuned until a reasonable match to the well operating point was obtained to set a base case for further investigation. The p-T phase envelop for fluid composition is shown in Fig. 2.

The critical point for this composition occurs at a pressure and temperature of 2827psi and 66°F.

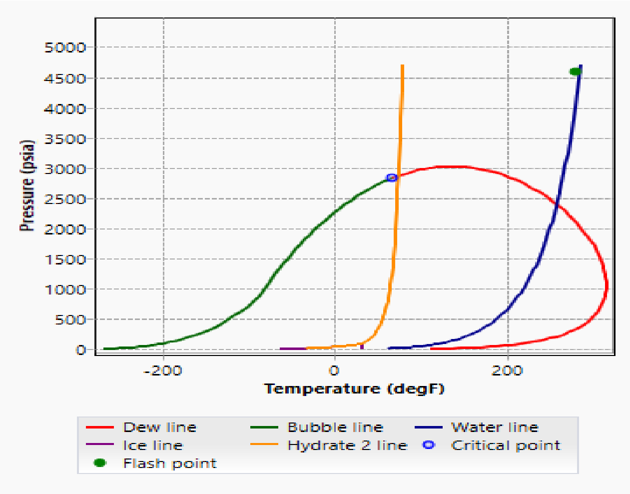


Fig. 2: p-T phase envelope for the fluid composition

Other phase properties such as density critical gas rate and critical velocity were determined at different flowing bottom-hole pressures using Turner liquid droplet model. Thereafter, the results from PIPESIM were moved to OLGA to simulate the flow regime and velocity profiles of the well. This provides valuable information into flow behaviour by transient flow modelling where flow variables are changing with time and space.

3. Results and discussion

3.1 Pressure-temperature profile

The Pressure-Temperature profile as shown in Fig. 3 was used to determine the critical loading velocity, which was further used in determining the onset of liquid loading. The relationship between the actual gas velocity and the critical loading velocity tells if there would be an onset of liquid loading (Riza et al, 2016, Belfroid et al, 2008). Table 3 shows the results from the profile plot.

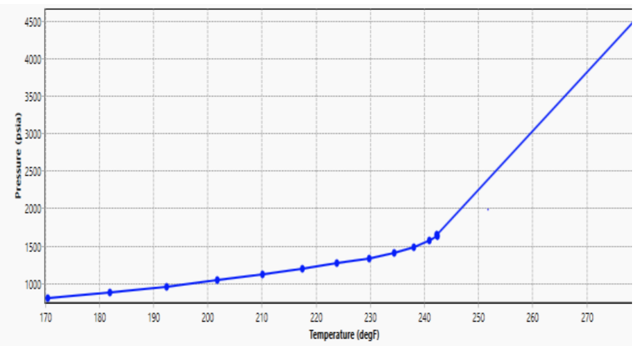


Fig. 3: Pressure-temperature distribution plot of the well

Table 3: Results from p-T distribution profile

S/N	Parameter	Value
1	Gas Rate [MMScf/d]	14.7
2	Flowing Bottombole Pressure	1637psia
3	Flowing Bottomhole	242°F
4	Flowing well Head Temperature	175.5°F
5	Flow Regimes in the Well	Annular,
6	Predominant Flow Regime	Annular

From the p-T distribution profile results, it was observed that the critical gas flow rate and critical velocities at every depth in the well is less than the gas rate and velocity of the well/The predominant flow regime (annular flow) supports liquid to be lifted out from the well. This implies that the development of liquid loading in the well would be delayed but can occur as production progresses and reservoir conditions changes with time.

3.2 Tubing size selection

Selecting an optimum tubing size helps in delaying the inception of liquid loading (Skopich et al, 2015). A sensitivity analysis on tubing sizes was performed using 2.441in, 2.992in, 3.476 and 3.598in tubing sizes respectively. Figure 4 shows the sensitivity profiles while Table 4 shows the flowrate from each tubing size. For each tubing size, the effects on the flow regime and liquid holdup was monitored and recorded.

Table 4: Results from sensitivity analysis on different tubing sizes

S/	Tubing	Gas rate
1	2.441	11.5
2	2.992	13.72
3	3.476	14.75
4	3.598	14.91

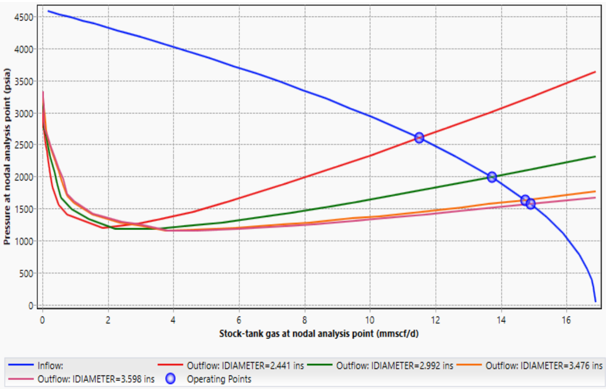


Fig. 4: Sensitivity analysis for various tubing sizes

To obtain an optimum tubing size, tubing selection was done by modelling the erosional velocity and results compared. The result showed that the 3.476in and 3.598in tubing had an erosional velocity less than 1. But the tubing ID 3.476 in was selected due to the cost difference. The sensitivity analysis of the erosional velocity plot is shown in Figure 5 while Table 5 shows the variation of different flow parameters due to changes in tubing size.

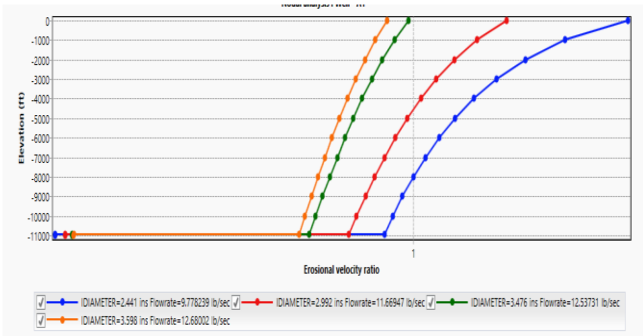


Fig. 5: Erosional velocity prediction for various tubing sizes

Table 1: Summary of the results for tubing size variation using PIPESIM

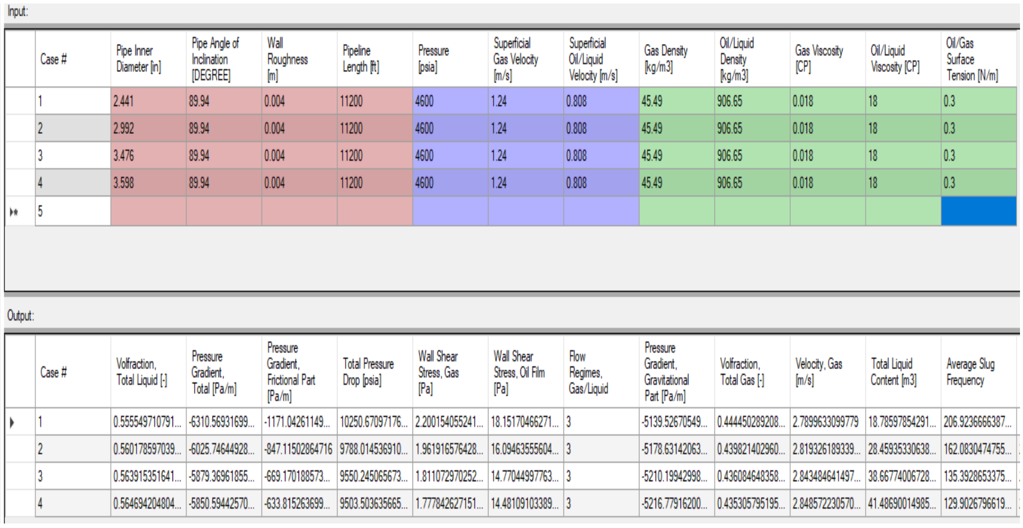
Tubing	2.441	2.992	3.476	3.598
Flow Rate	9.8	11.7	12.5	12.7
Nodal pressure (psia)	2597	1990	1637	1571
Erosional velocity	1.500	1.20	0.900	0.900
Gas Velocity (ft/s)	80.00	64.00	51.00	48.00
No of low regimes	2	1	1	1
Dominant flow	Annular	Annular	Annular	Annular
Liquid content in the pipe. (%)	3.126	3.070	3.075	3.079

A sensitivity analysis on choke size gave 1.419255in, as the optimum choke size for the well flow conditions. The impact of choke on the well was observed to have changed the flow pattern from a predominantly annular flow to a mixture of flow regimes which includes annular, slug and transition flows. Howbeit, slug flow became the predominant flow. This is because choke limits and controls production rate in order to protect surface equipment from slugging and to reduce sand problems (Rilwan et al 2022, Chidamoio and Akanji, 2024). In the process of reducing production, the gas rate reduces and as such the gas carrying capacity reduces also. This leads to accumulation of more liquid in the well, hence liquid loading problems. With the results obtained, choke at the surface of the well affects the flow regimes of the well and in turn leads to well loading. With the slug flow regime, the rate of liquid holdup in the well is greatly increased (AL-Dogail et al, 2022)

3.3 Results from OLGA

The information generated from the PIPESIM simulation was transferred to the OLGA software for further simulation. OLGA software allows the flow regime map and velocity profiles of a well to be viewed and provide valuable information into flow behaviour through transient flow modelling. The results from the simulation for the different pipe diameters using OLGA are seen in Fig. 6. As can be seen, at a depth of 11200ft, pressure of 4600 psia and tubing diameters of 2.441, 2.992, 3.476 and 3.598 inches, there are three (3) flow regimes occurring in each of the different tubing. These flow regimes are the bubble, slug and the annular flow. The flow regime map for these flow regimes is shown in Fig. 7. A well at a particular stage of its life may experience more than one flow regime.

Although there are more than one flow regime in the stream at that depth and pressure, the predominant flow regime is the slug flow for all the tubing sizes.



Input:

Case #	Pipe Inner Diameter [in]	Pipe Angle of Inclination [DEGREE]	Wall Roughness [m]	Pipeline Length [ft]	Pressure [psia]	Superficial Gas Velocity [m/s]	Superficial Oil/Liquid Velocity [m/s]	Gas Density [kg/m3]	Oil/Liquid Density [kg/m3]	Gas Viscosity [CP]	Oil/Liquid Viscosity [CP]	Oil/Gas Surface Tension [N/m]
1	2.441	89.94	0.004	11200	4600	1.24	0.808	45.49	906.65	0.018	18	0.3
2	2.992	89.94	0.004	11200	4600	1.24	0.808	45.49	906.65	0.018	18	0.3
3	3.476	89.94	0.004	11200	4600	1.24	0.808	45.49	906.65	0.018	18	0.3
4	3.598	89.94	0.004	11200	4600	1.24	0.808	45.49	906.65	0.018	18	0.3
5												

Output:

Case #	Volfraction, Total Liquid [-]	Pressure Gradient, Total [Pa/m]	Pressure Gradient, Frictional Part [Pa/m]	Total Pressure Drop [psia]	Wall Shear Stress, Gas [Pa]	Wall Shear Stress, Oil Film [Pa]	Flow Regimes, Gas/Liquid	Pressure Gradient, Gravitational Part [Pa/m]	Volfraction, Total Gas [-]	Velocity, Gas [m/s]	Total Liquid Content [m3]	Average Slug Frequency
1	0.555549710791...	-6310.56931699...	-1171.04261149...	10250.67097176...	2.200154055241...	18.15170466271...	3	-5139.52670549...	0.444450289208...	2.7899633099779	18.78597854291...	206.9236666387...
2	0.560178597039...	-6025.74644928...	-847.11502864716	9788.014536910...	1.961916576428...	16.09463555604...	3	-5178.63142063...	0.439821402960...	2.819326189339...	28.45935330638...	162.0830474755...
3	0.563915351641...	-5879.36961855...	-669.170188573...	9550.245065673...	1.811072970252...	14.77044997763...	3	-5210.19942998...	0.436084648358...	2.843484641497...	38.66774006728...	135.3928653375...
4	0.564694204804...	-5850.59442570...	-633.815263699...	9503.503635665...	1.777842627151...	14.48109103389...	3	-5216.77916200...	0.435305795195...	2.848572230570...	41.48690014985...	129.9026796619...

Fig. 6: Result from OLGA simulation with the different pipe diameters

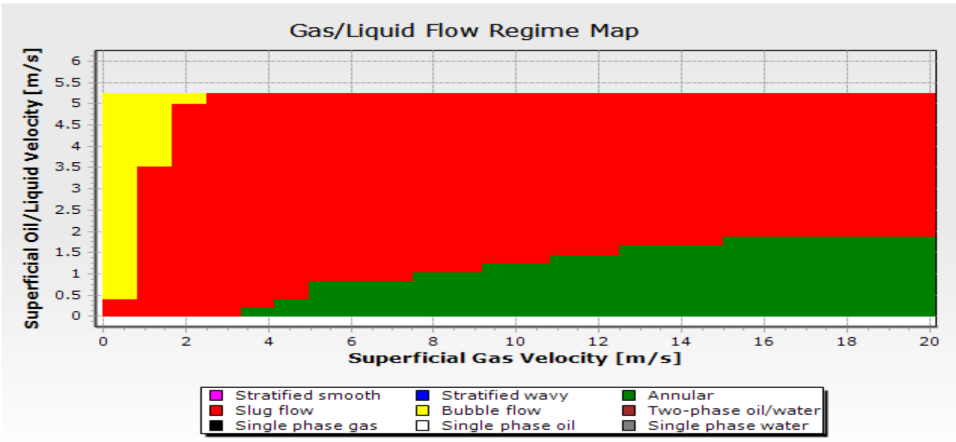


Fig. 7: Flow regime map

The tubing sizes with the highest velocities are the 3.476 in (2.85m/s) and 3.598 in (2.85 m/s) tubings as shown in Table 6. Recall that from the PIPESIM simulation, 3.476 was the optimum tubing size selected due to its flow rate and cost. Although this tubing size has a velocity greater than the calculated critical velocity, the flow is in the slug flow regime, and with this flow regime, the tendency for liquid to be accumulated in the well is high/As such, the simulation was run again to obtained a flow that will keep the stream in the annular flow regime.

Table 6: Summary of different tubing performance

Tubing Diameter (inches)	2.441	2.992	3.476	3.598
Velocity (m/s)	2.79	2.82	2.84	2.85
No of flow regimes	3	3	3	3
Types of flow regimes	Bubble, Slug and Annular	Bubble, Slug and Annular	Bubble, Slug and Annular	Bubble, Slug and Annular
Predominant Flow Regime	Annular	Annular	Slug	Slug
Liquid content in the pipe (m^3)	18.78	28.46	38.67	41.49

From Turner et al. (1968), to prevent liquid in a well, the flow must be in the annular or bubble flow regime. To keep the flow in the Annular or Bubble flow, the surface tension between the liquid and gas in the stream is set to 0.000056N/m which is the surface tension of the stream obtained from the PIPESIM simulation. The result obtained from the new simulation was slightly different from the former. The 2.441 and 2.992 inch tubings showed that the stream has two flow regimes which are the bubble flow and the annular flow whereas the 3.476 and 3.598 inch tubings maintained the same number of flow regimes as in the earlier simulation as shown in Table 7.

Table 7: Summary of result with a different surface tension

Tubing ID (in)	2.4411	2.992	3.476	3.598
Velocity (m/s)	3.47	3.68	3.33	2.84
No of Flow regimes	2	2	3	3
Flow Regimes	Bubble and Annular flow	Bubble and Annular flow	Bubble Annular and Slug flow	Bubble, Annular and Slug flow
Dominant flow regime	Annular	Annular	Annular	Slug
Liquid content (m^3)	3.89	9.05	11.65	46.21

Table 8: Summary of results from PIPESIM and OLGA

Tubing ID (in)		2.441	2.992	3.476	3.598
Nodal Rate (MMscf/d)	PIPESIM	11.5	13.7	14.7	17.9
Nodal pressure (psia)	PIPESIM	2597	1990	1637	1572
Erosional velocity	PIPESIM	1.82	1.46	0.90	0.88
Gas velocity (m/s)	PIPESIM	3.2	3.4	4.4	3.7
Gas velocity (m/s)	OLGA	3.47	3.68	3.33	2.84
No of flow regimes	OLGA	2	2	3	3
Dominant flow regime	OLGA	Annular	Annular	Annular	Slug
Liquid content (m^3)	OLGA	3.89	9.05	11.65	46.21

Following the emergence of annular from slug flow, the 3.476 inch tubing was eventually selected as the optimum tubing size. Basically, these results foreclose the importance of choosing rightly the optimum parameters for effective production and management of liquid loading prone wells.

4. Conclusion

This research investigated the impact of tubing sizes and flow regimes on liquid loading in a gas well. The critical velocities at different tubing sizes were determined which guides as one of the parameters for selecting the optimum tubing size. From the simulations using PIPESIM, it was observed that at reservoir temperature of 280 °F, pressure of 4600 psia and depth of 11200ft, the critical velocity was 2.51ft/sec which shows that liquid loading will not occur early in the well investigated. On these conditions, the optimum tubing size selected was 3.46 following its high flowrate and erosional velocity being less than 1. Thus, 3.476 inch tubing can effectively keep the well from liquid loading before pressure decline and cooling effects could trigger liquid accumulation. From the OLGA simulation, the following could be deduced:

1. The flow has three flow regimes, the bubble, Slug and annular flows.
2. All the tubing sizes that effectively lift liquid from the well all have a velocity higher than the critical gas velocity calculated using PIPESIM, although the erosional velocities of the smaller tubing sizes are greater than 1
3. Thus, the selected tubing size is the 3.476-inch tubing, because it has an annular flow regime and a high velocity which is above the critical velocity.

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