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Research Article

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Dynamic Modeling for Predicting the Onset Time of Liquid Loading in Gas Wells

Okon E. Ita[1]*, Dulu Appah[1], Ndubuka Chinedu Ikenna[3]

[1]Africa Centre of Excellence, Centre for Oilfield Chemicals Research, University of Port Harcourt, Nigeria
[2]University of Uyo, Nigeria

Abstract Liquid loading in gas wells is the accumulation of liquids in the wellbore due to pressure decline. It generally occurred as production rate decline with decreasing reservoir pressure and the well can no longer effectively lift the associate liquid to the surface. It has been one of the major challenging issues facing most mature gas fields in the Niger Delta. This study aimed at developing a transient model that will be able to predict the onset time and mitigate liquid loading in gas wells. Transient modeling is an essential component for feasibility studies and field development design. This study has focused on using OLGA dynamic multiphase simulator with multiflash software to model the dynamic interaction between reservoir and wellbore when liquid loading happens. It models time-dependent behaviors, or transient flow, to maximize production potential. Dynamic simulation is essential in deepwater and is used extensively in both offshore and onshore developments to investigate transient behavior in pipelines and wellbores.Reservoir/wellbore model was developed to predict the onset of liquid loading and simulate the subsequent unstable production period. From the results, it was observed that the onset time of liquid loading occurred after 21 hours and increases to 35 hours before the wellbore was totally accumulated with liquid. It was also discovered that after restarting the well, it was able to produce briefly but quickly load up and dies again. Finally, gas was injected through the annulus space into the downhole values to unload the well. In the simulation, it was observed that it takes about one hour for the injected gas to unload the well and then the liquid content in the wellbore decreases to zero. Using dynamic approach, we have added some inside into the process of liquid Loading and have looked into the new operation procedures that enable operators to move more quickly to diagnose well behaviour and determined how to minimize down time. Hence, dynamic modeling has the potential to serve as a comprehensive tool for operators to predict the onset of liquid loading and mitigate liquid loading in gas wells and other subsequence production challenges.

Keywords Dynamic Modeling, Prediction, Onset Time, Liquid Loading, Gas Wells

Introduction

Successful production system design and operations requires a detailed understanding of multiphase flow behavior. Flow modeling and simulation provides valuable insights into flow behavior, including the physics describing flow through the entire production systems, from reservoir pore to process facility. During vertical upward flow, due to buoyancy effects (density difference), it is expected that the gas will flow faster than the liquid. Similarly, depending on each of their velocities, the gas and liquid will present different topological distributions inside the pipe known as flow patterns. At high gas velocities, gas tends to move to the centre of the pipe forming a vortex commonly known as gas core. Liquid is then pushed out of the gas core and onto the pipe wall forming a film. Also, due to the high shear at the gas-liquid film interface, the liquid film is constantly atomized as droplets that are transported in the gas core while some are deposited back into the film. This flow pattern is known as annular-mist flow and it is the one preferred in gas wells that produce liquids. As gas velocity decreases, the liquid film starts to bridge the gas core and the liquid close to the pipe wall starts to fall back. This progressively leads to new flow patterns such as churn, slug and eventually bubble flow (lowest gas velocity). The amount of liquid per pipe section along the well is known as liquid holdup and varies depending on the flow pattern at hand. This also has an impact on pressure losses which have to be properly estimated along the well. Over time, an increasing presence of liquid in the well can create a recirculation zone that generates an excess pressure at the sandface that can hinder or, if high enough, stop gas production altogether. This is commonly known as liquid loading.

Several measures can be taken to solve the liquid-loading problem. Foaming the liquid water can enable the gas to lift water from the well. Using smaller tubing or creating a lower wellhead pressure sometimes can keep mist flow. The well can be unloaded by gas lifting or pumping the liquids out of the well. Heating the wellbore can prevent liquid condensation. Downhole injection of water into an underlying disposal zone is another option. However, liquid loading is not always obvious, and recognizing the liquid-loading problem is not an easy task. A thorough diagnostic analysis of well data needs to be performed. The symptoms to look for include onset of liquid slugs at the surface of the well, increasing difference between the tubing and casing pressures with time, sharp changes in gradient on a flowing pressure survey, and sharp drops in a production decline curve. Turner et al. [1] were the pioneer investigators who analyzed and predicted the minimum gas flow rate to prevent liquid loading. They presented two mathematical models to describe the liquid-loading problem: the film movement model and entrained drop movement model. On the basis of analyses of field data, they concluded that the film movement model does not represent the controlling liquid-transport mechanism. This project will focus on transient modelling using OLGA dynamic multiphase simulator. It will go straight to explain how transient simulation provides critical inside as key point in the life of a well. The fully coupled mechanism is widely acknowledging as unconditionally stable and fast [2]. The model which was first introduced by Stone et al. [3] discretize the well into segments in the axial direction and solves the well equations implicitly and simultaneously with the reservoir equations. The wellbore multiphase flow represented by the drift-flux model has been the most applied by most integrated wellbore-reservoir simulators Pan and Oldenburg [4]. However, Pan et al. [5] pointed out that the model cannot be applied in the mist flow regime. One of such regime was proposed by Hasan et al. [6], which was later applied by Riza et al. [7] to understand liquid loading phenomenon in vertical gas wells.

Some authors [8-11] have proposed coupled reservoir/wellbores modeling to liquid loading in transient conditions. Although these models provide reasonable solutions for liquid loading in transient conditions, these studies can still not explain all liquid loading symptoms observed in the field. Other authors proposed methods to describe liquid loading under transient conditions using reservoir and tubing performance relationships. For instance, Oudeman [12] proposed the use of multiphase reservoir performance and vertical flow performance of the tubing to improve prediction of wet-gas-well performance and liquid loading. Following this approach, Dousi et al. [13] has proposed the use of reservoir inflow performance coupled with a tubing flow performance curve to explain the process of water buildup and drainage in the gas wells under transient liquid loading conditions. Dousi et al. [13] also defined the conditions called "metastable" which is observed in the field. Chupin et al. [14], Veeken et al. [15] and Whitson et al. [16] also proposed metastable flow using field data. The authors define metastable flow as subcritical rates that a well under liquid loading conditions would flow. Limpasurat et al. [17] have proposed the use of new boundary conditions for a coupled reservoir/wellbore modeling method that was validated with field data. These authors concluded that this new boundary condition can show that the metastable flow observed in the field, as originally suggested by Dousi et al. [13].

Many remedial lifting options have been developed for use in the field; some unloading solutions (e.g. velocity strings) rely on the existing natural energy of the system, while others (e.g. downhole pumps) provide extra energy to bring the water to surface, so reducing the liquid loading problem. As each of the remedial options have their own technical characteristics, their applicability varies depending on the characteristics and the status of the well. Lea et al. [18] presented an extensive technical review of well-established techniques to alleviate the effects of liquid loading. According to Lea, "the method that is most economic for the longest period of operation is the optimum method. The criteria for selecting the optimum method are: methods in similar fields that are used successfully, vendor equipment availability, reliability of equipment, manpower required to operate the equipment, and lifting capacity." Park et al. [19] developed a decision matrix to help screen the possible remedial options available to the operator. The matrix aims to provide a critical evaluation of solutions to liquid loading in gas wells vis-à-vis the existing technical and economic constraints, and also serves as a quick screening tool for the selection of production optimisation strategies. In what follows, a critical review of current methods to forecast the onset of liquid loading and model the subsequent wellbore performance is presented, in line with the work by Zhang et al. [20]. The review also includes more recent attempts to understand the dynamic interactions between reservoir and wellbore during liquid loading. Churn flow is unarguably the most complex and least understood regime of gas-liquid flow in vertical and inclined pipes.

Rodriques et al. [21] presented a model to improve the pressure gradient calculations when the flow is in the stratified to annular transition region. The model takes into account the thin film that is formed in the gas-wall interface. Predictions are compared to high-pressure, large diameter data available in the literature and show improvements when compared to the results of other models. At lower gas flow rates in slightly inclined pipes, low liquid loading flow present an intermittent flow behavior. Alsaadi et al. [22], Fan et al. [23], and Fan et al. [24] studied the onset of liquid accumulation in inclinations ranging between 2 and 30 from horizontal in a 0.0662 m ID pipe with air and water as flowing fluids. Alsaadi [22] measured several parameters including the critical gas velocity where liquid starts to accumulate [23].

Methodology

This project focuses on transient modelling using OLGA dynamic multiphase simulator with multiflash software to model, investigate, simulate and mitigate liquid loading in gas wells.OLGA is a general purpose transient simulator for modelling fluid flow in flow lines and pipeline systems. It is a product licensed by the Schlumberger. Multiflash is a powerful and versatile system for modelling physical properties and phase equilibria. It has a comprehensive set of configurable options, making it easy to specify all aspects of a study.Reliable production data from gas well operating in the Niger Delta were obtained and the behavior of the well was analyzed.Reservoir/wellbore model was developed to predict the onset of liquid loading and simulate the subsequent unstable production period (Figure 1). First, the well was shut down for 48 hours to see whether the reservoir pressure around the wellbore can build up to a point at which when the well would have reopened, it can unload itself and continue production. Again, we tried to use gas lift injection to unload the well since the well did not restart successfully after shutting down and restarted the well. Gas was injected down the annulus and it entered the tubing string through downhole values. The gas lightened the liquid column and this eventually unload the well.

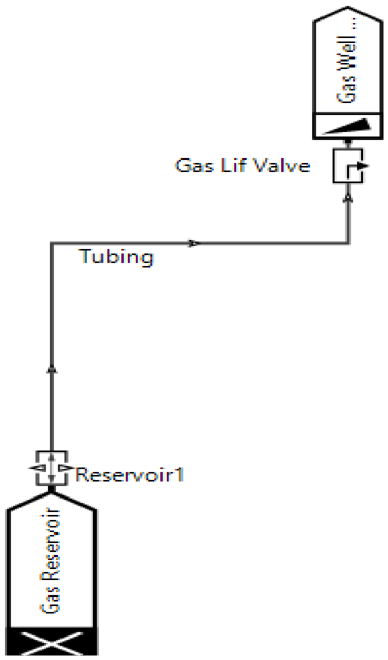

Figure 1: Reservoir/Well Model

Results and Discussion

Here, we can see several views of what happened During Liquid Loading. Figure 2 plot shows the different stages (A to D) of increasing liquid content in a gas well during production. From Figure 2, well A shows the liquid content at zero time. Well B shows the onset time of liquid loading in the wellbore. Well C shows the increasing liquid content in the wellbore after the onset of liquid loading and well D shows the rate of liquid accumulation in the wellbore. From Figure 2, it can be seen that the liquid loading occurred after 21 hours (well B) and increases to 35 hours before the wellbore is totally accumulated with liquid(well D). The plot shows how the liquid in the well gradually build over the perforation until the hydrostatic forces in the column of fluid are too high for the reservoir to overcome. Lastly, we can see the total amount of fluid in the wellbore and how long it takes the gas rate to equal zero which in this case is 35 hours (Figure 3). Liquid loading obviously has a detrimental impact on production because the well become unstable or to suffer down time (Figure 4). It was critical to be able to restart the well after we detected that it ceased flowing. We first shut down the well for 48 hours to see whether or not the reservoir pressure around the well can build up to a point at which when the well is reopened it can unload itself. If we look at this case, the well is able to produce briefly but quickly load up and dies again. This can be clearly seen in the oil and gas content trend plot (Figure 5 and 6).

The simulation, we can see that this takes about one hour and then water content in the well decreases to zero (Figure 8).

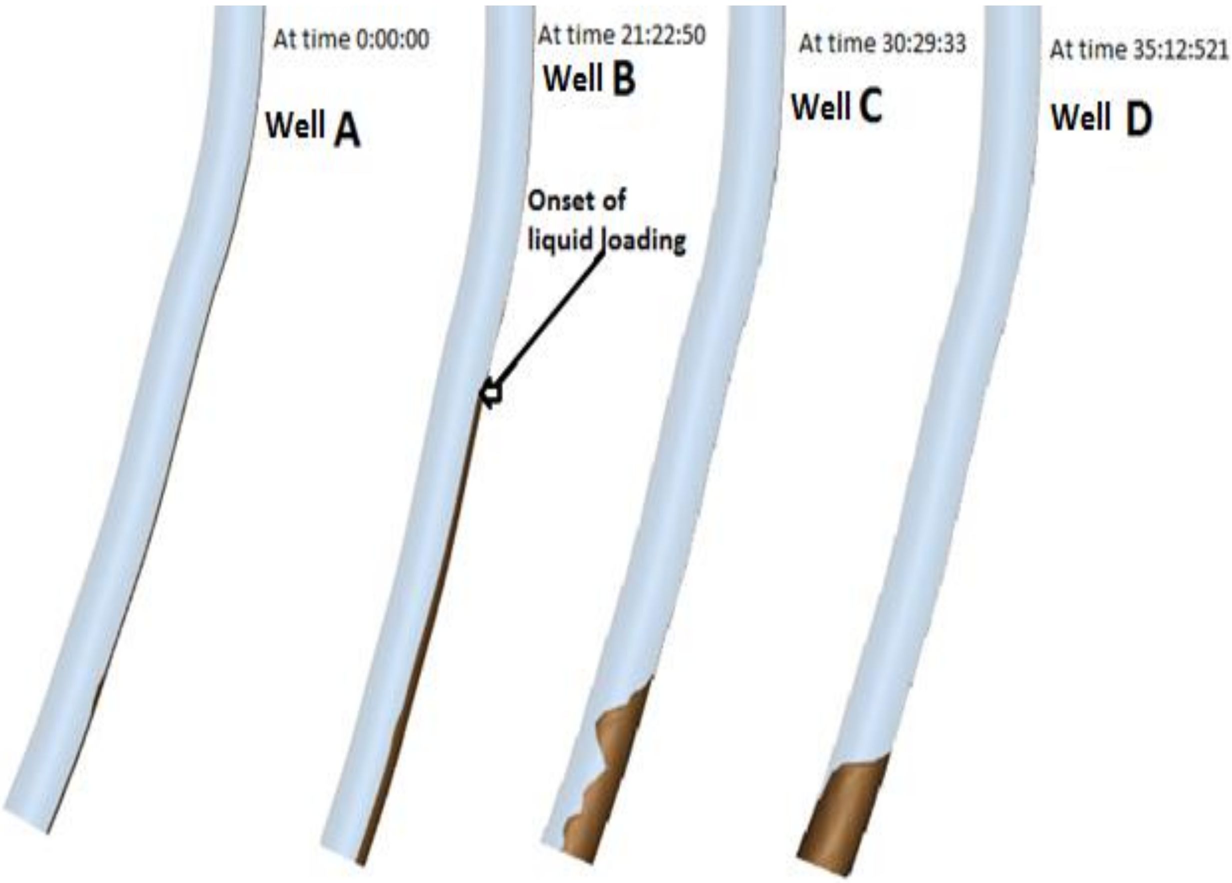

Figure 2: Liquid Holdup distribution in Gas Well

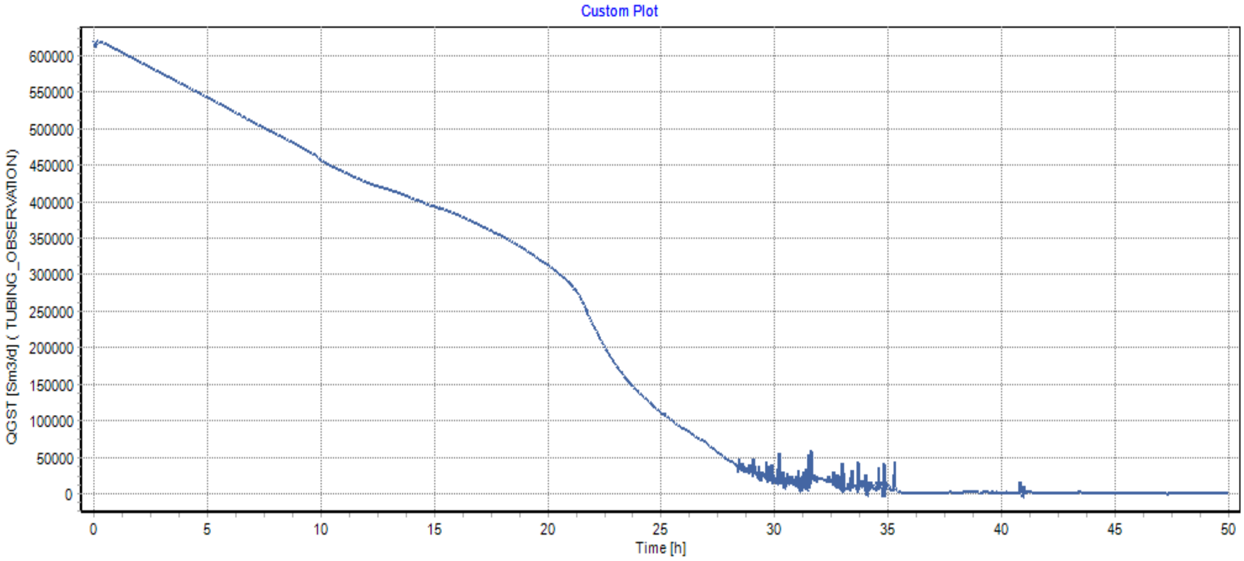

Figure 3: Gas Production Performance before Shutdown

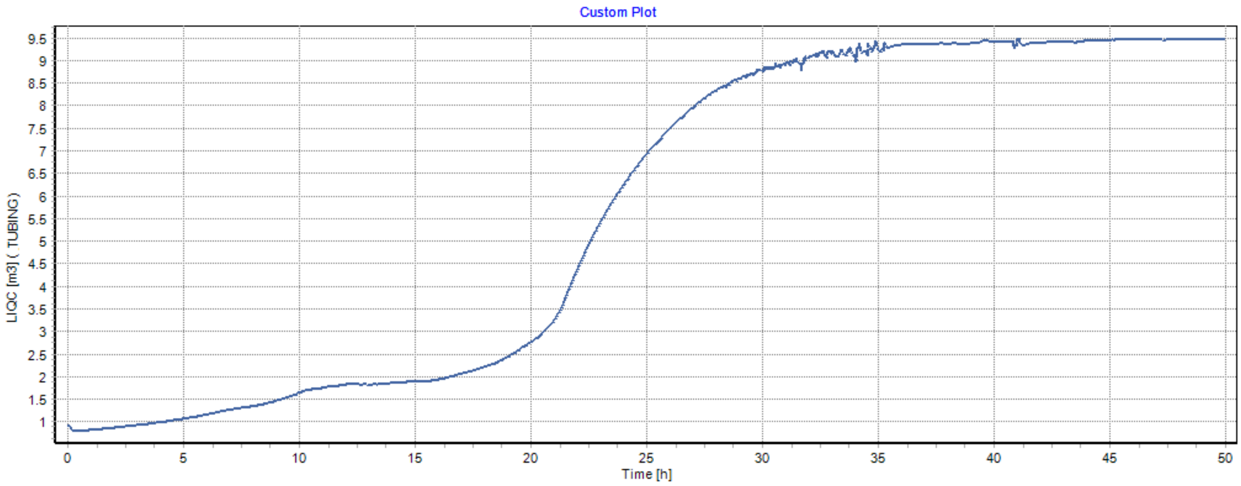

Figure 4: Increasing Liquid content in Gas Well before Shutdown

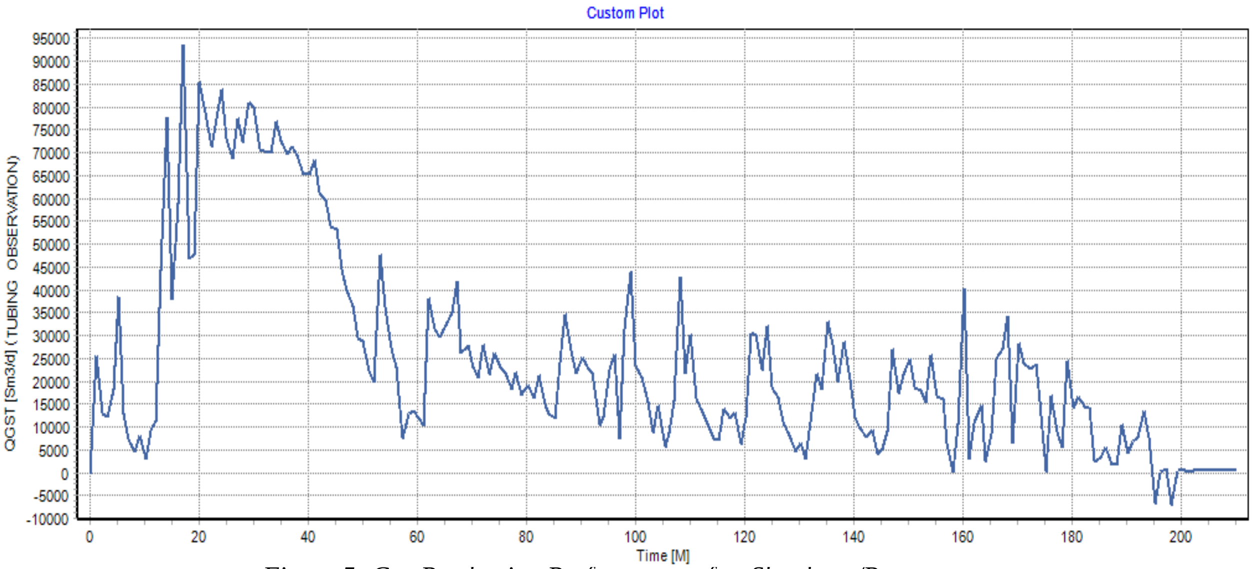

Figure 5: Gas Production Performance after Shutdown/Restart

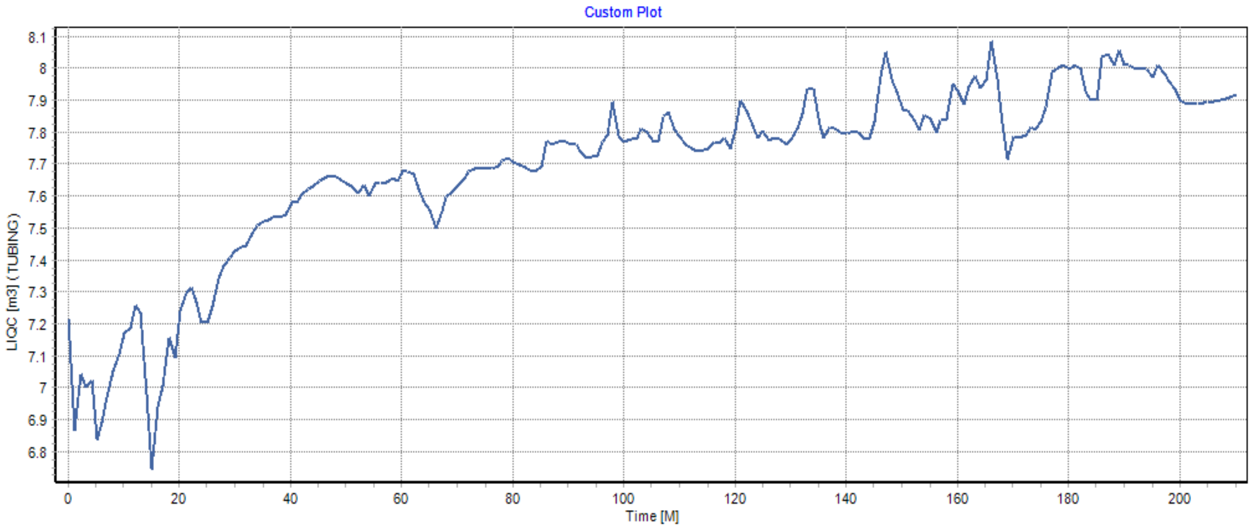

Figure 6: Increasing Liquid Content in Gas Well after Shutdown/Restart

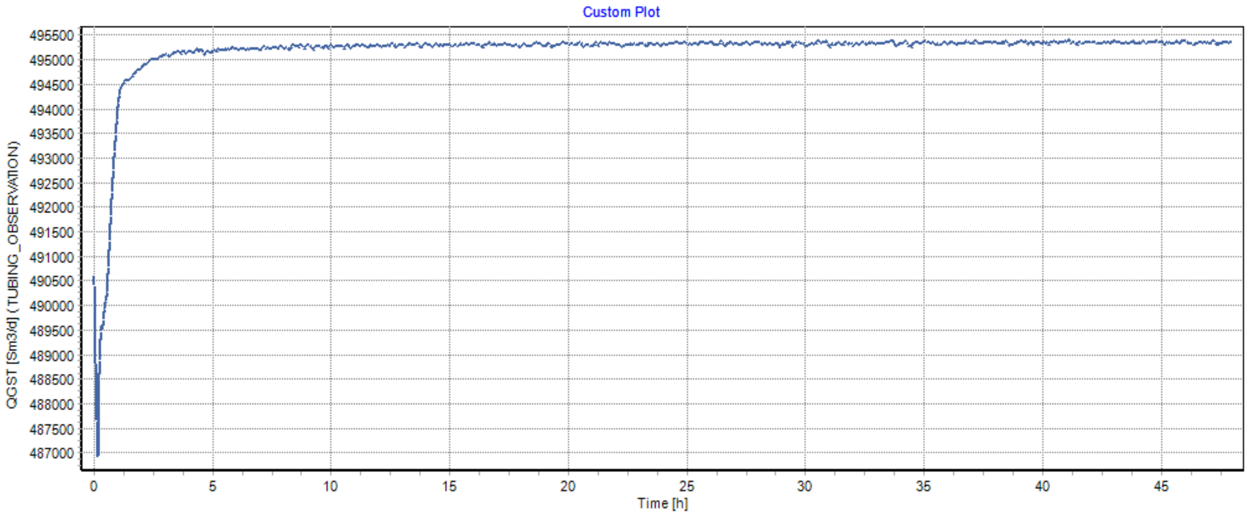

Figure 7: Increasing Gas Production after Gas Lift Injection

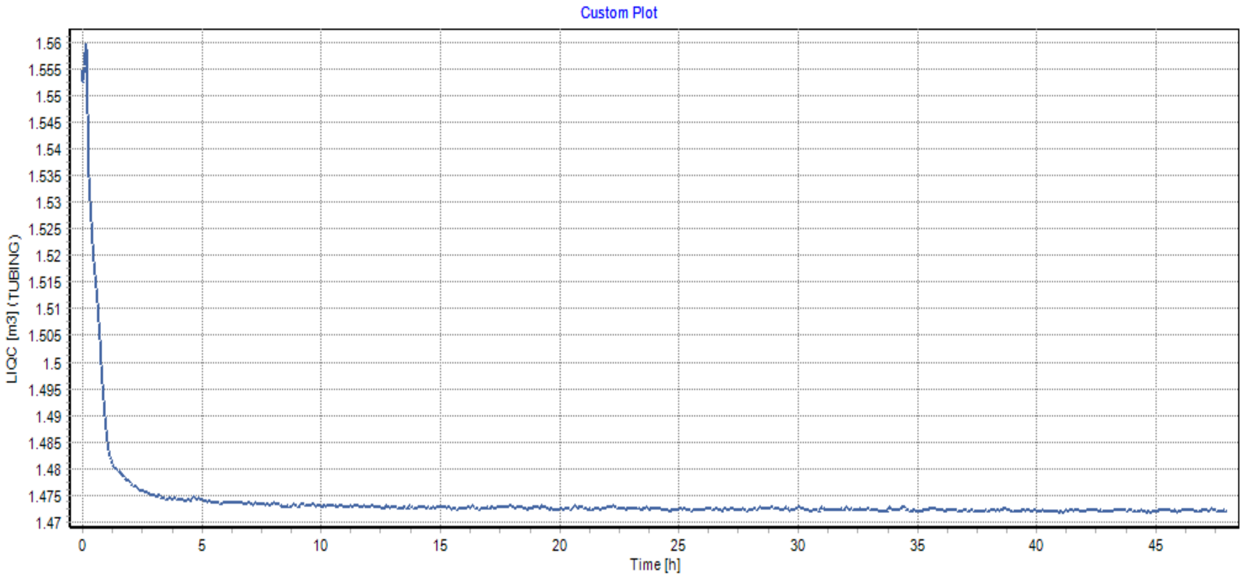

Figure 8: Decreasing Liquid content in Gas Well After Gas Lift

Conclusion

In this study, we developed an integrated model (wellbore-reservoir) to investigate the dynamic interaction between wellbore and reservoir using field data obtained from an oil company operating in the Niger Delta region of Nigeria. From the results, it was observed that the onset time of liquid loading occurred after 21 hours and increases to 35 hours before the wellbore was totally accumulated with liquid. Using dynamic approach, we have added some inside into the process of liquid Loading and have looked into the new operation procedures that enable us to move more quickly to diagnose well behaviour and determined how to minimize down time. Hence, dynamic modeling has the potential to serve as a comprehensive tool for operators to predict the onset of liquid loading and the subsequent wellbore challenges.

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