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Monitoring of Gas Well Liquid Loading Using Integrated Variable Approach

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Abstract

Liquid loading in gas well is a worrisome situation that cannot be neglected at the early stage of gas field development or at the commencement of production. It can affect well production to the point of killing the well. In this paper, Multiphase flow (LPG and Water) experiment was conducted in 0.37 inch and 0.47 inch tubings on UAC Excellence flow loop facility. The changes in the flow variables of; temperature, downhole pressure, flow rate, flow time and water cut were integrated graphically and analysed for liquid loading. Mist flow and slug flow were obtained during the experiment. The multiphase fluid changed in the physical state from liquid gas to condensed liquid gas during loading. The result of the graphical relationships that exist between downhole pressure and water cut, downhole pressure and flow time and temperature, downhole temperature and flow rate could reliably be used for monitoring liquid loading in gas wells. The experimental approach proved more reliable and more prototypes of flow loop are needed for the study of the control factors for liquid loading in gas wells.

Keywords: Liquid loading, Tubing, UAC Excellence Flow loop, integrated, monitoring

I. INTRODUCTION

A gas well is said to be loaded when the flowing gas velocity drops below a certain "gas critical velocity," and the gas can no longer lift the liquids (hydrocarbon condensate liquid or reservoir water) up to the surface. The liquid fall back and accumulate at the bottom of the well and reduce gas production, or even "kill" the well [6]. Gas wells suffering from liquid loading could present several symptoms at the early stage or later stage of occurrence. Liquid loading caused decline in production rate and in most extreme cases may stop the well from flowing or die if not detected and managed early. When pressure drop in the wellbore increases, the gas flow velocity will decrease and the bottomhole pressure will increase. At this point, the effective gas permeability near the wellbore is reduced as water saturation increases. This would certainly hamper gas production rate due to the backpressure effect that renders the reservoir pressure negligible to push the gas to the wellhead. However, as the transport energy reduces, the water or liquid hydrocarbon at the wellbore cannot more be transported to the surface and this perhaps lead to liquid loading. Reference [4] highlighted the symptoms of a loaded gas well to include sharp drop in cumulative production, unexpected changes in pressure gradient, the beginning of liquid slugs in the downstream facilities, low and long sharp temperature at the wellhead, increment in water production and reduction in oil-gas ratio. The percentage of produced water expected before loading phase in a gas well was not related to how it could signify that a well is loaded.

He emphasised on the need for a system that can model flow transition from annular to churn, churn to slug, then bubble which terminate the flowing life of gas well. The conclusion follows the need for a more realistic experimental approach and a predictive model for proper selection of remedial solution for gas wells with loading problem.

Many researchers have developed various models on how to predict and control liquid loading, the most popular ones are [7]. Two physical models were presented, the movement of liquid film along the pipe walls and liquid droplets entrained in high velocity gas core. The study shows that their critical terminal velocity model is a function of gravitational force, the drag force and force of buoyancy [9]. Many solutions exist for addressing this problem, but the application of these solutions depends on the severity of the problem which in most cases could begin at the early stage of production. Reference [1] created a new model for the prediction of liquid loading in gas wells based on established models of [7], [5] and [3]. Transient time and kinetic term for liquid loading which were not considered by the formers were factored in the Adesina's model. The flow rates of the different tubing size were determined based on time interval. The use of turner's field data for the validation of the model posed some concern on the efficacy of the model. Variation in fluid PVT properties were not put into consideration, the assumed values for the interfacial tension for condensate-gas and gas-water could introduce some inconsistent in application of the model for lower or higher values or interfacial tension.

Reference [2] developed empirical correlation which was for liquid loading prediction based on multiphase upward flow measurement in a long vertical pipe known as flow-pattern-dependent correlation. The empirical model designed to analysed and diagnosed liquid loading culmination process was observed in a study to have predicted liquid content and corresponding flowing bottomhole pressure before gas production ceased to flow in a well. This was developed strictly for wellbore liquid prediction without considering the reservoir conditions that could lead to the liquid in the well. Again the critical velocity of the well is dependent on the reservoir energy and the flowing properties of reservoir rock. During production, gas well exhibit many characteristic sparing from steady to unsteady etc. Thus, adopting the steady state condition limit the deployment of the model in real time production conditions. Reference [2] experimental work had some limitations which are fundamental to liquid loading study. The flow behaviour in different tubing sizes was not considered in the investigation which could have broadened the validation and the application of the flow loop for different production configuration.

II. METHODLOGY

The concept of integrated variables approach in this paper involves the study and the interpretation of the graphical relationships of the data variables of downhole pressures, temperature, water cut, flow rate and time interval obtained from the simulation of multiphase flow experiment in 0.3 inch and 0.47 inch tubings on UAC Excellence Flow Loop. This flow loop is a new facility that utilizes liquefied petroleum gas (LPG) and water as near reservoir fluids for multiphase flow experiment (Figure 1) [8].

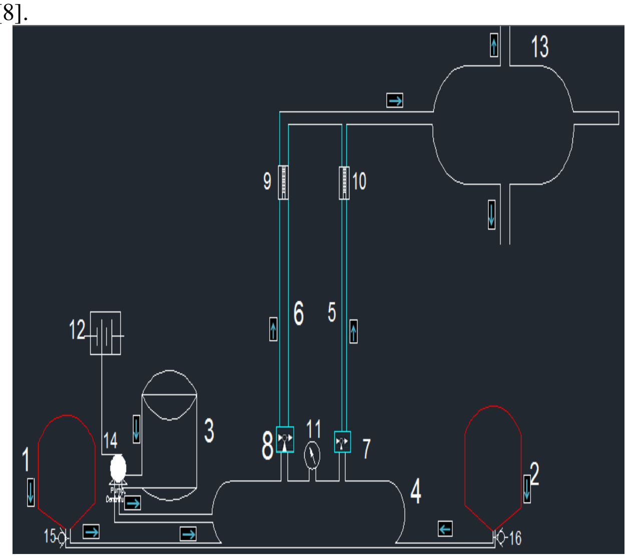

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Figure 1: UAC Excellence Flow Loop Schematic (Udoaka *et al.,* 2021)

Table .1: Summary of UAC Excellence Flow Loop

1	Gas Reservoir 1
2	Gas Reservoir 2
3	Water Reservoir
4	Wellbore Section
5	0.37 inch tubing
6	0.47 inch tubing
7	Wellbore control valves 1
8	Wellbore control valves 2
9	Flow Metre 1
10	Flow Metre 1
11	Downhole pressure gauge
12	12 Volt DC battery
13	Vent section
14	Centrifugal Pump
15	Gas reservoir 1 control Valve
16	Gas reservoir 2 control Valve

III. RESULTS

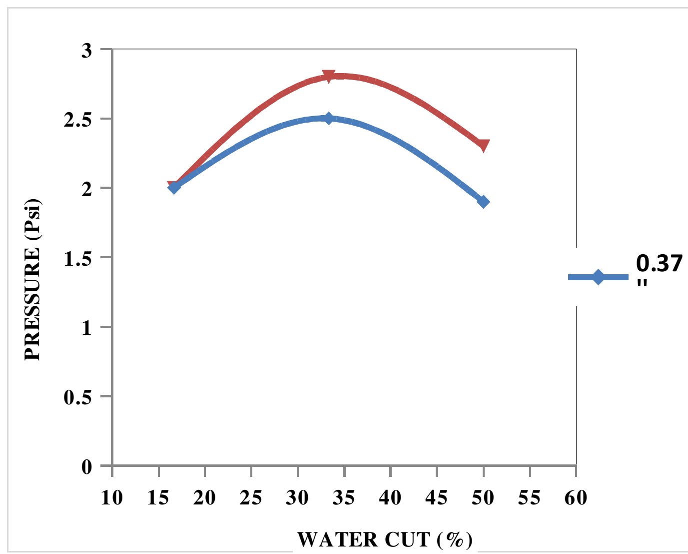

Figure 2: Downhole Pressure and Water Cut Plot for 0.37 and 0.47 inch Tubings

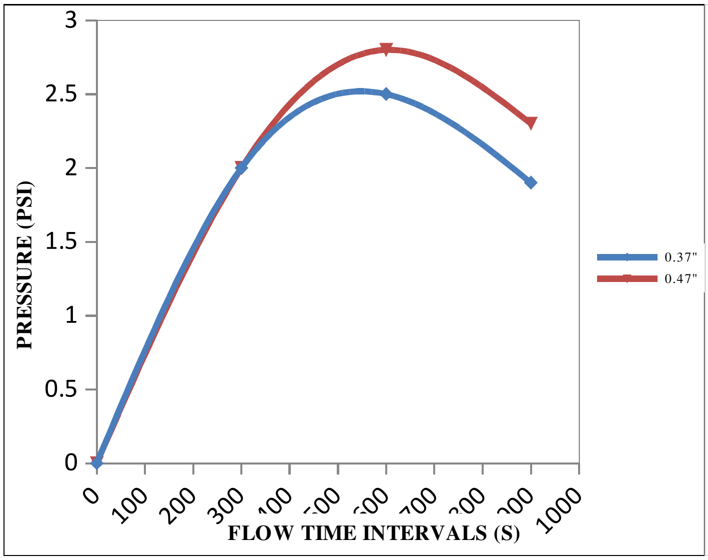

Figure 3: Downhole Pressure and Flow time intervals Plot for 0.37 and 0.47 inch Tubings

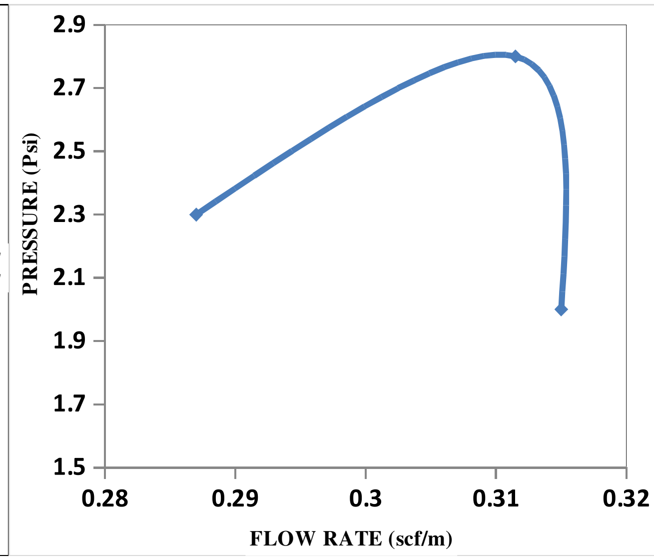

Figure 5: Downhole Pressure and Flow Rate Plot for 0.47 inch Tubing

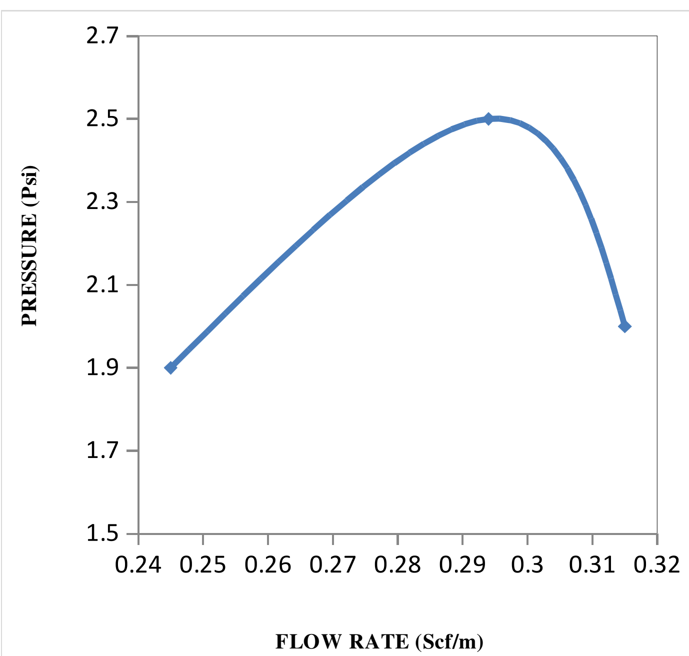

Figure 4: Downhole Pressure and Flow Rate Plot for 0.37 inch Tubing

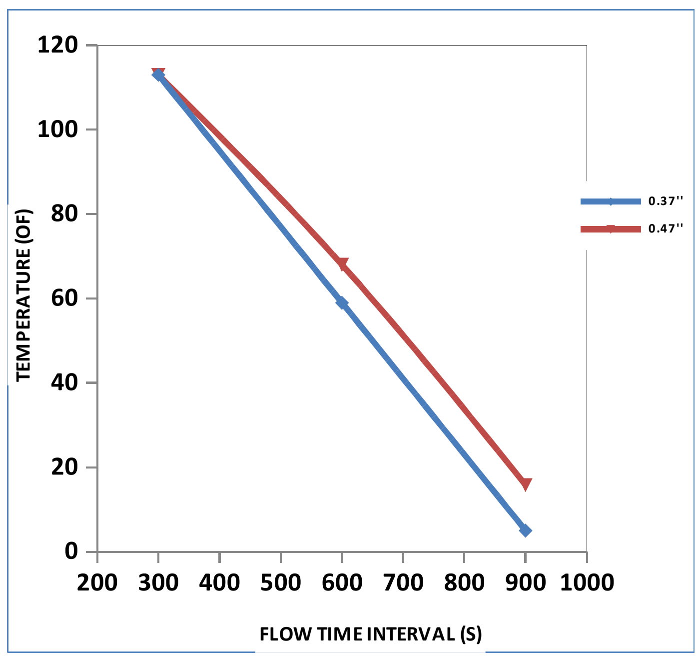

Figure 6: Temperature and flow time interval Plot for 0.37 and 0.47 inch tubings

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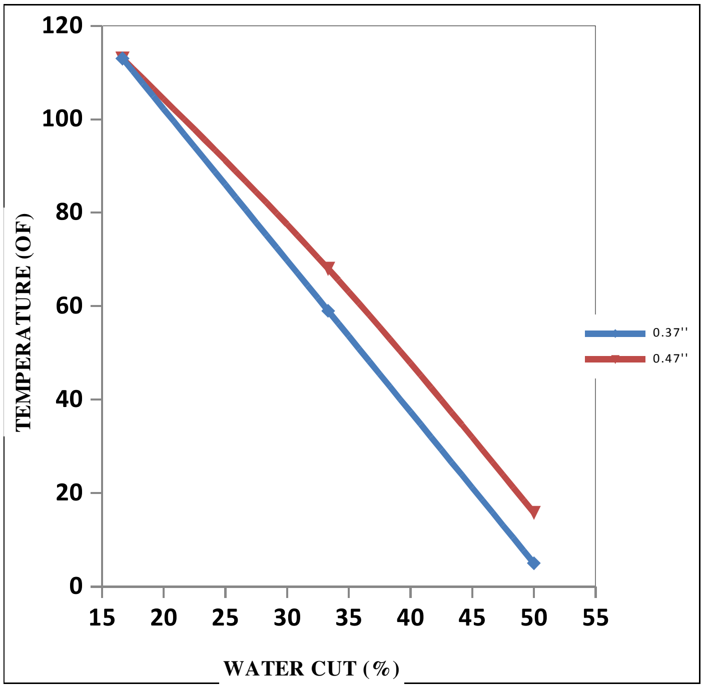

Figure 7: Water Cut and Downhole Temperature Plot for 0.37 inch and 0.47 inch Tubings

Figure 9: Condensed multiphase fluid from the vent section exit.

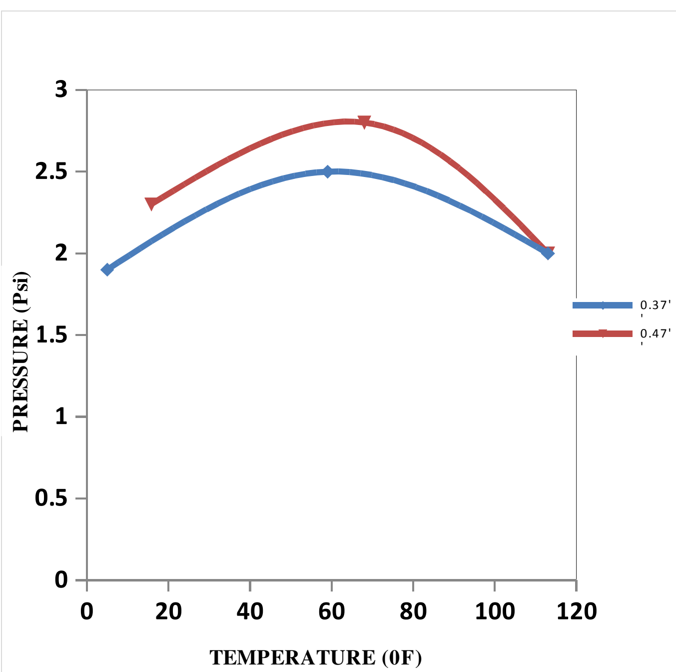

Figure 8: Downhole Pressure and Temperature Plot for 0.37 inch and 0.47 inch Tubings

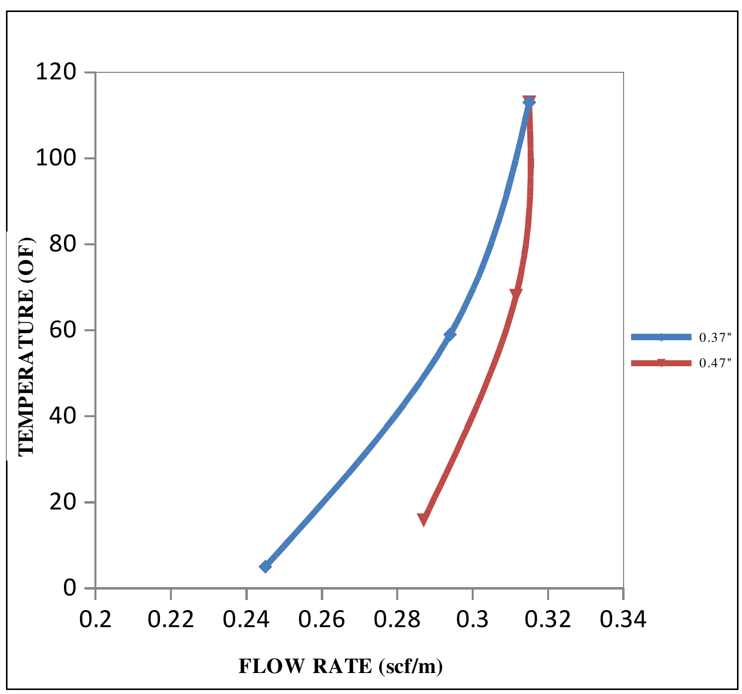

Figure 10: Downhole Temperature and Flow rate Plot for 0.37 inch and 0.47 inch Tubings

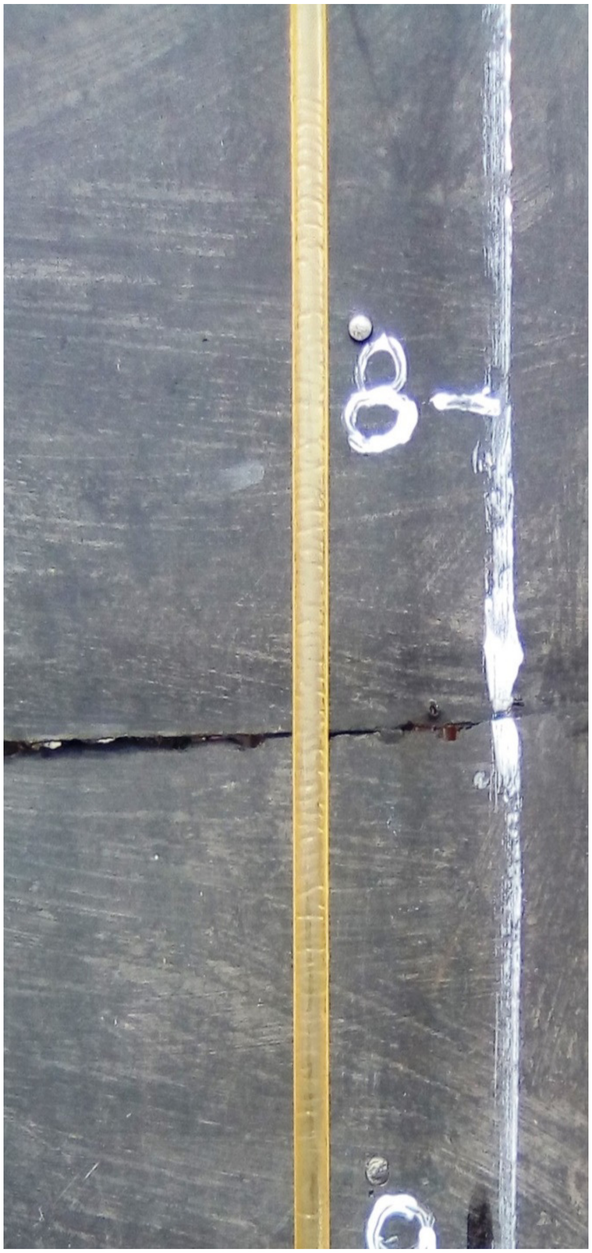

Figure 11: Experimental Visualized Mist flow

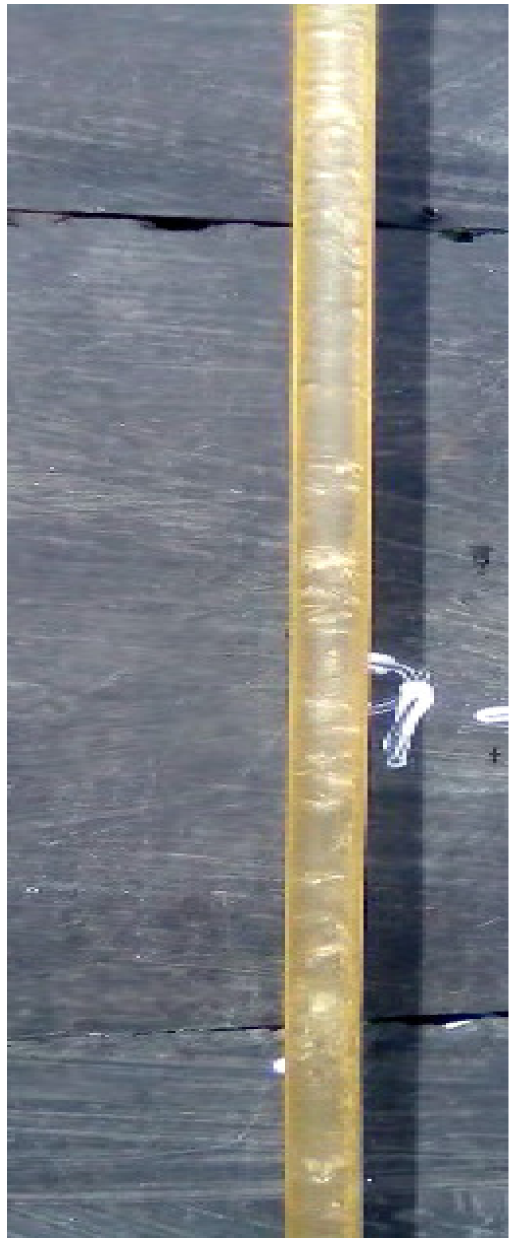

Figure 12: Experimental Visualized Slug flow

IV. DISCUSSION

The analysis of the graphical relationships arising from the integration of the data variables obtained from the simulation of multiphase flow in 0.37 inch and 0.47 inch tubings is the focus of this discussion. The pressure and water cut plots (Figure 2) shows an increased in pressure to water cut from 10% - 30%. Above the 30% water cut, the curve shows a decline in the pressure of the flow in the two tubings, thus, indicating the onset of liquid loading in the two tubings. Similarly, mist flow (Figure 11) was also observed in the upper part of the tubing at the height of 1 foot during the experiment which later changed to slug flow from the height of 8.0 feet to 12.0 feet (Figure 12). The changes in flow regime occurred when water cut went above 30% in the two tubings. The downhole pressure and flow time intervals plot is another relationship that serves as a quick look to the production performance of gas wells. Figure 3 shows the relationship for downhole pressure and flow time intervals for the 0.37 inch and 0.47 inch tubings. From Figure 3, downhole pressure maintained an increasing trend from 0-300 seconds and retarded after 300 seconds of flow to 600 seconds. At 600 seconds the downhole pressure declined rapidly. The time intervals for the changed in the shape of the curves in Figure 3 also correspond to the time interval for the occurrence of the visualized flow regimes in Figures 11 and 12. Thus, the three phases identified in figure 3 are; stable flow phase, onset of liquid loading phase and continuous loading phase. Figures 4 and 5 shows the relationship between downhole pressure and flow rate for 0.37 inch and 0.47 inch tubings. From the relationship, the steady increase in downhole pressures and flow rates represent a none-loaded flow. From the pressure of 2.5 psi and flow rate 0.29 scf/m, the curves show a decline in the pressure with less significant increase in the flow rate for 0.37 inch tubing (Figure 4). Similarly, Figure 5 also show a steady decline in the downhole pressure and flow rate of 2.8 psi and 0.31 scf/m for 0.47 inch tubing. The downhole pressure decline indicates liquid loading, and the effect is much significant in 0.47 inch tubing compare to 0.37 inch tubing. Figure 6 is the temperature and flow time interval relationship for 0.37 inch and 0.47 inch tubings. From the curves the temperature of the flowing system decreases with time. When this is compare with Figures 6 and 7, the curves shows a similar trend which brings to the understanding that the occurrence of liquid loading in gas wells is usually accompanied with low well temperature, and this also could serve as early indicator for monitoring the onset of loading. Figure 8 represent the downhole pressure and temperature relationship. From the left of the curves, a decrease in temperature with an increasing downhole pressure which peaked at the pressures of 2.8 psi for 0.47 inch tubing and 2.5 psi for 0.37 inch tubing which later declines at the temperature below 20^{o}F. From the peak of the curve to the right, the flowing system was predominantly liquid gas while from the peak of the curves to the Left, the flowing system exhibited predominantly condense liquid gas. Hence, it is found that the multiphase fluids usually undergo some physical changes in the state of the fluid in the wellbore during liquid loading. Some of the changes observed in this research are: liquid gas and condensed liquid gas (Figure 9). Figure (10) is the temperature and flow rate relationship for 0.37 inch and 0.47 inch tubings. From the curves, flow rate increases with increasing temperature and declines as temperature decreases. In line with the kinetic molecular theory, the increased in the water cut in the wellbore decreases the kinetic energy of the gaseous phase of the fluid required to lift the fluids to the vent section (wellhead). From these curves, it could be deduced that, a sudden drop in the wellhead temperature of a gas well followed by a slowly continuous drop in the temperature indicates liquid loading.

V. CONCLUSION

The success of liquid loading monitoring in gas wells is independent on few variables. It requires the integration of multiple variables relationships in order to view the well production performance in different ways. In this research, the following conclusions are drawn:

1. Multiphase flow experiment on UAC excellence flow loop provides multiple variables that could serve as a base for studying and monitoring liquid loading in gas wells.
2. During Liquid loading phase, multiphase fluids undergo changes in the physical nature of the fluids (ie liquid gas to condense liquid gas) (Figure 9).
3. Mist flow and slug flow were recorded during the experiment (Figures 12 and 13) at 600 seconds and 900 seconds respectively.
4. The use of experimental data provide a more reliable base for studying the responses of the multiphase flow variables to the percentages of water cut present in the wellbore at different time interval.
5. Figures 2, 3, 8 and 10 can be use reliably for liquid loading monitoring in gas wells.
6. The downhole pressure and flow time intervals could serve as a quick look for monitoring liquid loading in gas wells (Figure 3)

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