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INVESTIGATING THE INFLUENCE OF SOME WELL AND FLUID PARAMETERS ON THE ACCUMULATION OF LIQUIDS IN GAS WELLS

Amieibibama Joseph, Ngowari O. Ikiriko*

Department of Petroleum Engineering, University of Port Harcourt, Port Harcourt, Nigeria

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Abstract

During gas well production, it is easier to produce accumulated liquids (water or condensate) from wells with high gas flow rates than low rate wells to the surface. As pressure depletes, the carrying capacity of gas of entrained liquids reduces, inhibiting efficient production of gas and accumulated liquids to the surface. Whereas pressure depletion is naturally synonymous with depletion of finite resource in the reservoir, inadequate design and deterioration of well and fluid properties could influence and accelerate fast depletion of bottomhole flowing pressure; which is primarily responsible for the transport of accumulated fluids in the wellbore to the surface. In this paper, some well and fluid properties (tubing size, wellhead pressure, condensate-gas ratio and water-gas ratios) are investigated to determine how they influence and exacerbate accumulation of liquids in the wellbore. It was observed that irrespective of the tubing size used, at wellhead pressures up to 2000psi, the well quits flowing and larger tubing sizes increases gas rate, however may quit flowing at early times due to slugging resulting from higher liquid rates. Also, increase in condensate-gas ratio and water-gas ratio in the wellbore promotes increase in liquid accumulation in the wellbore.

***Keywords**: Liquid loading; Condensate-gas ratio; Water-gas ratio; Wellhead pressure; Tubing ID.*

1. Introduction

Like oil wells, gas wells experience tenacious production decline during their lifetime due to depletion and associated well problems [1]. Liquid loading is one of the imminent problems gas wells undergo and has made gas wells susceptible to early shut downs. Liquid loading is the inability of gas wells to lift and continuously lift liquids that are co-produced with the gas from the wellbore. The inability of the gas to lift produced liquids out of the well results to the accumulation of these liquids (water or condensate or both) at the wellbore and thus increase in the bottomhole flowing pressure [2-3]. The increase in the bottomhole flowing pressure imposes a back pressure on the adjacent reservoir which drastically causes outright reduction of gas production or killing of the gas well [4-5].

Liquid loading is not easy to detect [6] and upon occurrence can lead to the cessation of production if no timely identification, prevention or remediation is carried out. It is a multiphase flow phenomenon and its occurrence has always been connected to the existential flow regimes in the wellbore [7-9]. In this paper, some well and fluid properties are investigated to determine their influence on the accumulation of liquids in the wellbore

Liquid loading does not just happen but follows a mechanism of occurrence and depending on the system, the following can constitute the source of liquids in gas wells [10].

i. Heavier fractions condensation: mass transfer occurs between phases during condensation. Leading to liquid droplets falling out of gas and accumulating at the bottom of the wellbore or impinge on the wall of the pipe. The droplets on the wall of the pipe increase the liquid film thickness which then trickles down and accumulates at the bottom of the wellbore when it exceeds its carrying capacity.

ii. Entrained liquid droplet deposition: this being similar to that of condensation of heavier fractions except it does not involve mass transfer between the phases but an actual phase change.
iii. Direct incursion of liquids into the wellbore: this is a major source of liquids. Liquids are directly produced into the wellbore. This mechanism has the highest effect in liquid loading problems especially when the liquid is water from an adjacent aquifer. This hinders gas well productivity because gas is soluble in water.

Fig.1 shows the sequence of liquid loading occurrence in a typical gas well. In Fig. 1(a) the gas well flows as a mist with very high flow rate capable of lifting all produced liquids to the surface. However, due to depletion and associated well/reservoir problems, pressure declines and the liquid carrying capacity of the gas drops, leading to the emergence of annular flow where deposition and entrainment of impinged liquids on the wall of the pipe causes the build-up of liquid films. At the onset of annular flow, part of these liquids will trickle down and accumulate at the bottom of the wellbore as shown in Fig. 1(b). As flow conditions deteriorate, there ensues massive accumulation of liquids at the wellbore arising from flow reversals from liquid films from the wall and falling of liquid droplets from the core of tubing as shown in Fig.1(c). If timely measures are not taken, the conditions will deteriorate further with massive accumulation of liquids that exerts a back pressure on the adjacent formation that may eventually kill the well as shown in Fig. 1(d).

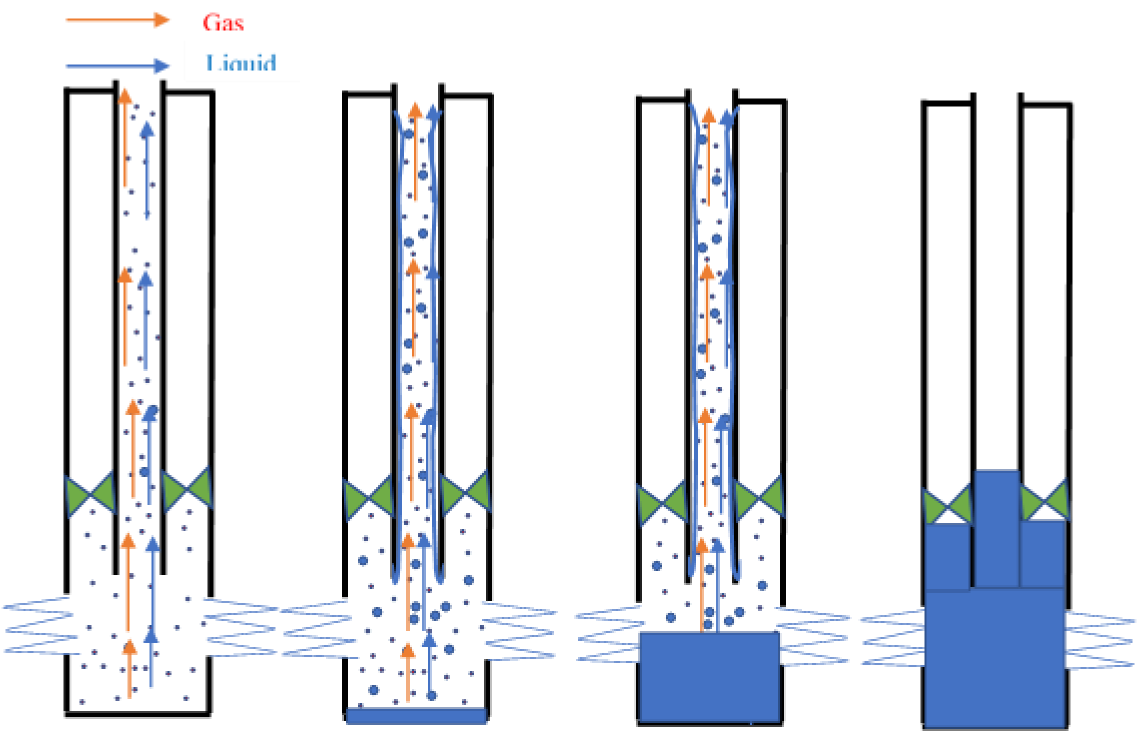
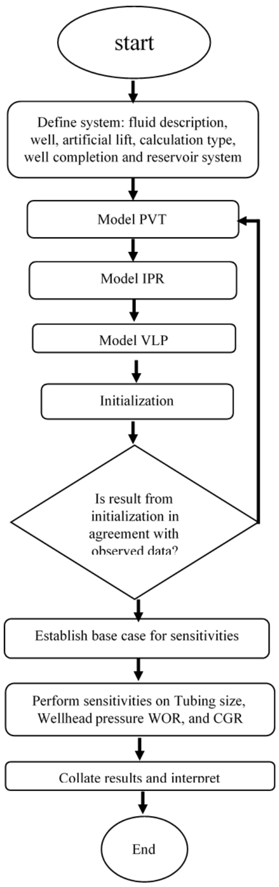


Fig. 1: Sequence of Liquid loading process in a gas well (a) Onset of gas well production with high gas rate flowing as mist flow where ever liquid produced is carried along with the gas as mist (b) Moderately high pressure gas production with entrainment and deposition liquids on the wall to build liquid film allowing some to trickle to the bottom of the well (annular flow) (c) Flow condition deteriorates with obvious liquid film reversal and deposition of liquid droplets at the wellbore liquid content (churn flow) (d) Massive liquid build-up at the wellbore and the liquid exerting a back pressure on the adjacent formation and thereby, killing the well

Liquid loading can present itself as a problem for high rate/high pressure wells as well as low rate/low pressure wells. The difference depends on tubing string size, surface pressure, amount and density of liquids produced along with the gas [12]. In this paper, the effects of some well and fluid properties are investigated to determine their influence on liquid accumulation in gas wells.

2. Method



The principle of Nodal Analysis was used to investigate four parameters: tubing size, well head pressure, condensate-gas ratio and water-oil ratio to determine their impacts on liquid accumulation in gas wells using PROSPER. This was achieved using data from Niger Delta.

The work flow is as shown in Figure 2. Using the acquired data, the well and fluid properties were inputted to appropriately describe the system. Thereafter, pressure-volume-temperature (PVT) data was matched. The IPR which describes the flow of formation fluid into the wellbore and the VLP which describes flow of fluid from the well to the surface was simulated using the appropriate data. Using the wellbore as the solution node, initialization was done to ensure that the current flowing conditions of the well is closely/correctly predicted. Where the predicted conditions are at variance with the actual, some of the data with high degree of uncertainty were tuned until a match was obtained.

Fig. 2. Flow chart used for designing PROSPER

3. Results and discussions

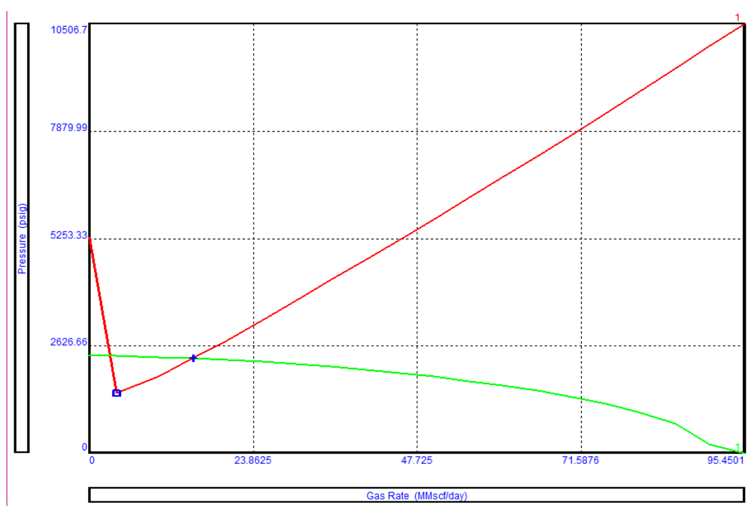


Fig. 3. System plot showing the base case scenario

After the initialization, the base case was obtained as shown in Figure 3. Figure 3 shows a gas well in metastable state with double intersections on the IPR curve. The true solution node is the point of intersection to the right rather than to the left asterix blue at 1968. 35psig and 12.498 MMscf/day whereas, the minimum point at 1520.7 psig and 4.375 MMscf/day is the onset of liquid loading in this well.

3.1. Effect of tubing sizes

Choosing optimum tubing sizes is paramount for effective and efficient production of gas wells. Various tubing sizes such as: 2.441, 3, 3.5, 4, 4.5 and 5 inches were investigated to determine their impact on liquid accumulation as shown in Figure 4. As can be seen in Figure 4 and Table 1, the larger the tubing size, the higher the gas and liquid production rates and vice versa. However, as can be seen in Table 1, the increase in the tubing sizes and the subsequent increase in the liquid production results to decrease in the bottom hole flowing pressure (BHFP). Hence, larger tubing sizes cause additional pressure loss which results to slugging and promotes liquid accumulation while smaller tubing sizes acts as velocity strings but enhances excessive frictional and erosional losses [13].

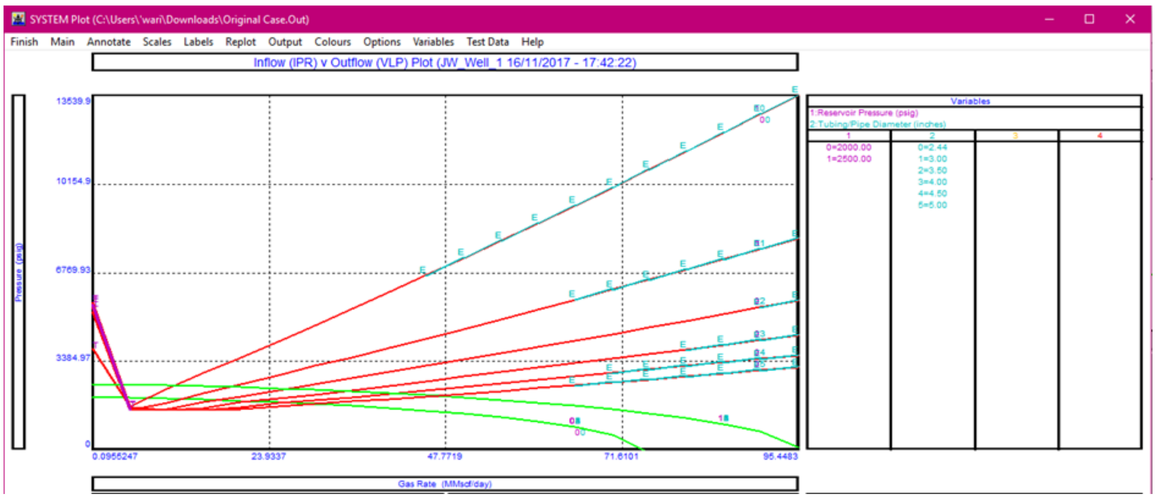


Fig. 4. VLP/IPR matching showing various tubing sizes

Table 1. Effect of variation of tubing sizes on fluid flow rates

@Wellhead pressure = 500 psig; @CGR = 40STB/MMscf
@WGR = 2.03 STB/MMscf

Tubing size	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
2.441	12.011	480.5	24.4	2447.70
3	20.237	809.5	41.1	2390.74
3.5	28.875	1155.0	48.6	2308.55
4	37.711	1508.4	76.6	2201.15
4.5	45.782	1831.3	92.9	2081.02
5	52.440	2097.6	106.5	1962.29

3.2. Effect wellhead pressure

Another parameter investigated to determine its influence on liquid loading is the wellhead pressure. Excessive increase in the wellhead pressure significantly inhibits efficient flow of hydrocarbons during production [14]. An increasing wellhead pressure will reduce the flow of gas and affect the vertical lift performance particularly when its value approaches the wellbore flowing pressure. Different values of wellhead flowing pressures of 500, 875, 1250, 1625 and 2000 psig were arbitrarily chosen and sensitized as shown in Fig. 5 with a 4inch tubing size.

From Fig. 5, out of the five wellhead pressures arbitrarily selected for a 4 in. tubing size, it was observed that the well produce at all the pressures except for the wellhead pressure 2000 psig. Moreover, as the wellhead pressure increases, the gas, oil and water rates decrease while a slight variation in the bottom hole flowing pressure was observed as shown in Table 2.

Table 2. Effect of wellhead pressures on fluid flow rates on a 4in. tubing

@Tubing size = 4 in.; @CRG = 40 STB/MMscf
@WGR = 2.03 STB/MMscf

Wellhead Pressure	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
500	37.711	1508.4	76.6	2201.15
875	34.047	1361.9	69.1	2248.93
1250	27.644	1105.8	56.1	2321.31
1650	20.887	835.5	42.4	2384.97
2000	-	-	-	-

This is as a result of the fact that the increase of the wellhead pressure imposes a restriction on the vertical lift following a slight change in the bottomhole flowing pressure (p_{wf}). For an efficient vertical lift, the difference between the bottom hole flowing pressure and wellhead pressure should be reasonably high. Similar trends were also observed with a tubing size of 2.441 in. when the wellhead pressure was gradually increased from 500 to 2000 psig at the same water-gas-ratio and condensate-gas ratio as shown in Table 3.

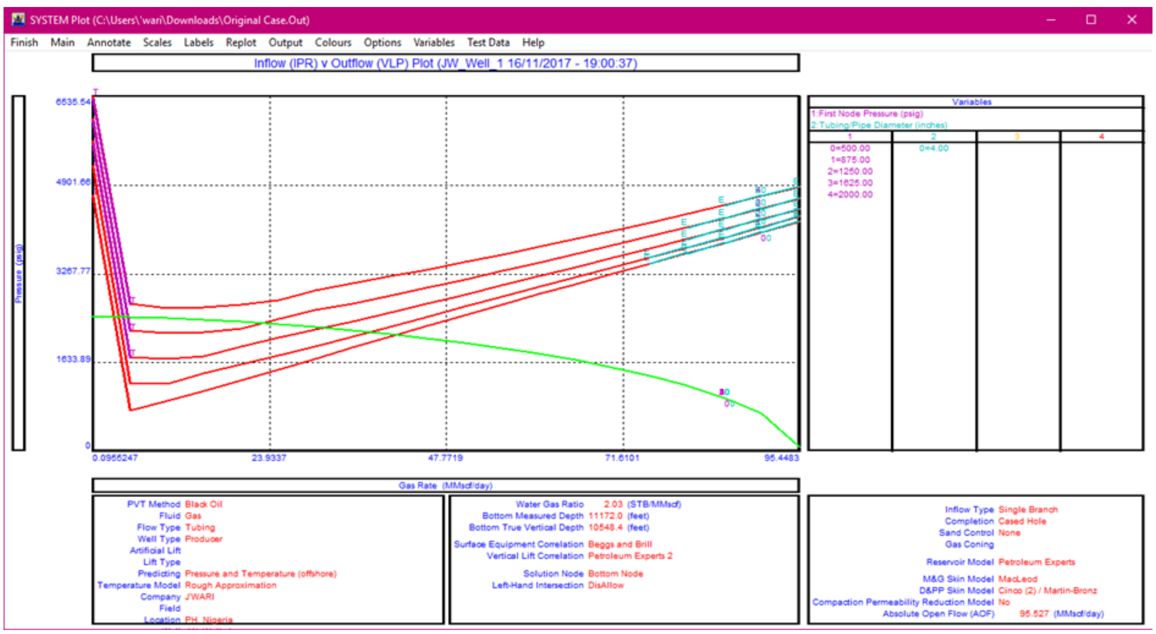


Fig. 5. System plot showing various wellhead pressures for a 4 in. tubing

Table 3. Effect of wellhead pressures on fluid flow rates on a 2.441 in. tubing

@Tubing size = 2.441 in.; @CRG = 40 STB/MMscf
@WGR = 2.03 STB/MMscf

Wellhead Pressure	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
500	12.011	480.5	24.4	2447.70
875	10.785	431.4	21.9	2455.13
1250	9.086	363.4	18.4	2464.00
1650	6.382	255.3	13.0	2476.73
2000	-	-	-	-

3.3. Water-gas ratio (WGR)

Fig.6 shows effect of varying water-gas ratio on liquid accumulation in gas wells. Again, five different values of WGR's: 2,6, 10, 25 and 50 STB/MMscf were sensitized to investigate the impact on liquid accumulation. Although the impact as shown in Fig. 6 seemingly looks small, it is obvious that as the WGR increases, the gas and oil rates decrease while the water rate increases as shown in Table 4 respectively. The increase of the WGR could be due to direct incursion from an adjacent aquifer, channeling or leaks. Since gas is soluble in water, a sudden and significant increase in the WGR would result not only in loading but outright killing of the gas well due the back pressure it will impose on the adjacent formation [15-16].

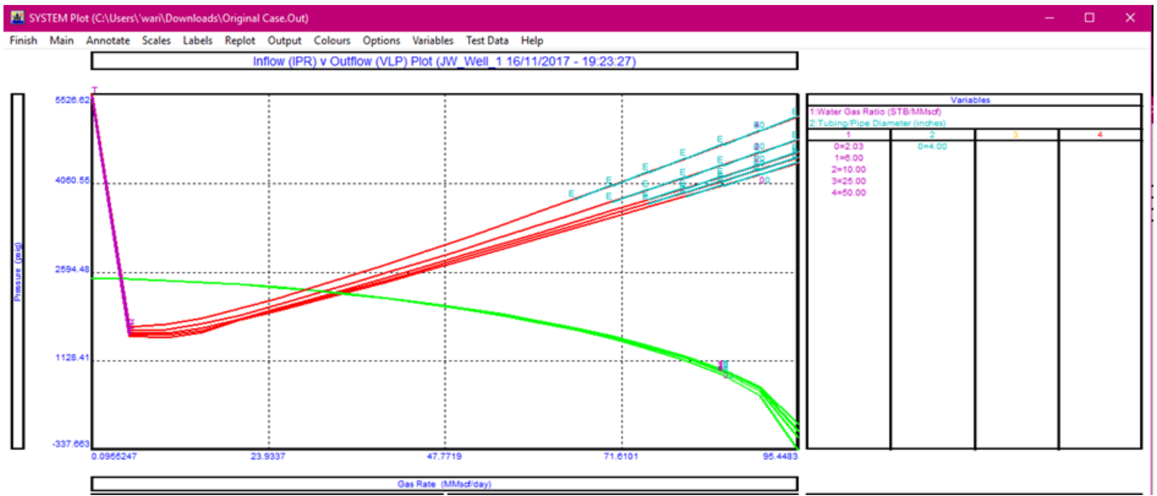


Fig. 6. System plot showing impact of WGR on liquid loading

Table 4. Effect of variation of Water Gas Ratio on fluid flow rates on a 2.441in. tubing

@Tubing size = 2.441 in.; @CRG = 40 STB/MMscf
@Wellhead pressure = 500 psig

Water Gas Ratio	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
2.03	12.011	480.5	24.4	2447.70
6	11.792	471.7	70.7	2448.95
10	11.810	472.4	118.1	2448.75
25	11.508	460.3	287.7	2450.29
50	10.598	423.9	529.9	2455.46

3.4. Effect of condensate-gas ratio

Another parameter investigated is the condensate-gas ratio (CGR) as shown in Figure 7. Four values of CGR: 0, 40 60 and 80 STB/MMscf were investigated. A Zero CGR value implies dry gas production; which can occur at early stages of production. As can be seen in Tables 6 and 7 at 2.441 and 4 in tubing sizes, the gas, oil and water rates decrease while the BHFP increases as the CGR increases. An increase in CGR leads to build-up of liquids [17] in the wellbore like that of WGR previously discussed. And build-up of liquids generally increases the BHFP which inhibits the flow of reservoir fluid into the wellbore by exerting back pressure on the adjacent formation.

Table .6. Effect of variation of Condensate Gas Ratio on fluid flow rates on 2.441in tubing

@Tubing size = 2.441 in.; @Wellhead pressure = 500 psig
@WGR = 2.03 STB/MMscf

Condensate Gas Ratio	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
0	13.551	0	27.5	2439.40
40	12.011	480.5	24.4	2447.70
60	11.367	682.0	23.1	2451.31
80	10.786	862.9	21.9	2454.61

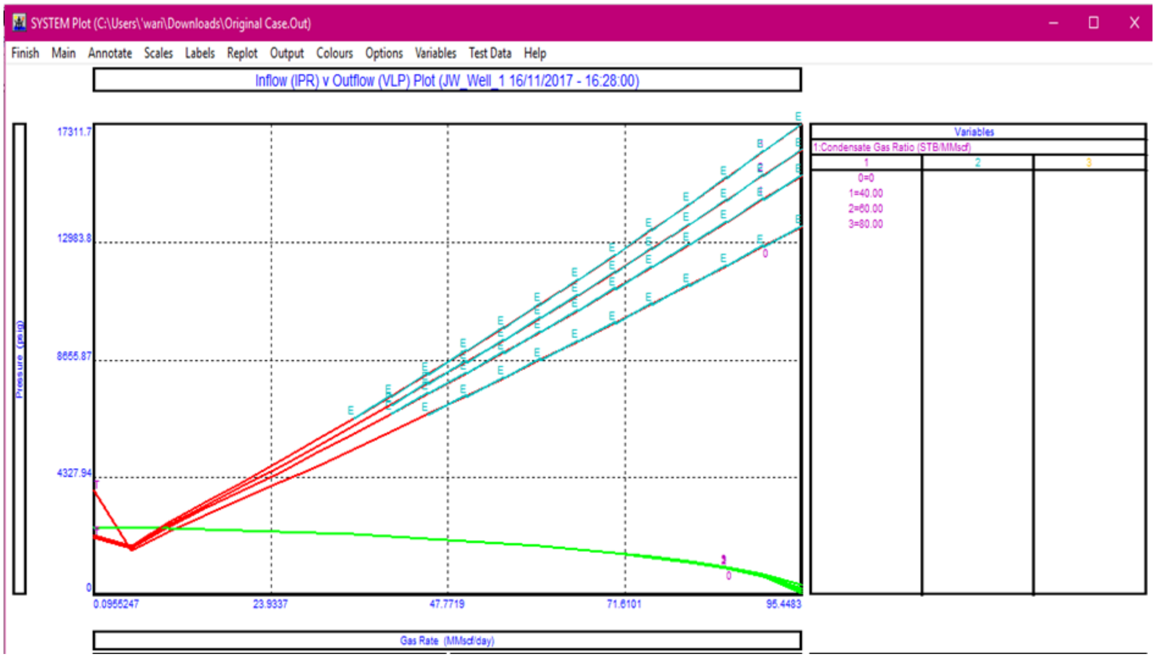


Fig. 7. VLP/IPR matching showing various CGR

Table 7. Effect of variation of Condensate Gas Ration on fluid flow rates on 4in. tubing

@Tubing size = 4 in.; @Wellhead pressure = 500 psig
@WGR = 2.03 STB/MMscf

Condensate Gas Ratio	Gas Rate (MMscf/day)	Oil Rate (STB/day)	Water Rate (STB/day)	BHFP (psig)
0	41.241	0	83.7	2152.60
40	37.71	1508.4	76.6	2201.15
60	36.181	2170.9	73.4	2223.00
80	34.768	2781.5	70.6	2243.05

4. Conclusion

The gas well loading phenomenon is one of the most serious problems that reduces and eventually cuts production in gas well. The phenomenon occurs as a result of liquid accumulation (water or/and condensate) in the wellbore. Over time, these liquids cause additional backpressure on the reservoir which results in a continual reduction of transport energy. Moreover, when a well starts slugging during production can give an even larger chance of liquid accumulation that completely overcomes the reservoir pressure and causes the well to die. From this investigation, it is obvious that tubing size, wellhead pressure, water-gas ratio and condensate-gas ratio can significantly impact on production from gas wells. Improperly sized tubing in gas wells can be detrimental and the wellhead pressure must be monitored to prevent excessive increase that can limit the tubing performance. In all, adequate well specific analysis is paramount to monitor and determine minimum gas rates to unload wells and investigate options for optimizations in order to efficiently and effectively produce gas wells.

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To whom correspondence should be addressed: Dr. Amieibibama Joseph, Department of Petroleum Engineering, University of Port Harcourt, Port Harcourt,, E-mail: Amieibibama.joseph@uniport.edu.ng