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Gas lift allocation optimization using Pipesim network optimizer

Nyelebuchi Amadichuku *, Ugwunna Dickson Amadi, Abu Robin and Ndidi Uzoigwe

Department of Petroleum Engineering, Rivers State University, 500101Port Harcourt, Nigeria.

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Abstract

This work maximizes oil production from a network of gas lift wells and determines the optimal amount of lift gas with PIPESIM network optimizer. PIPESIM was used to build a couple wellbore-flowline model and its network optimizer was utilized to maximize oil production from a network of gas lifted wells. Two wells were created (Well A and B) and connected to their respective flow lines to a manifold and from the manifold to the central processing facility (CPF) represented by a sink node. A comparison of the oil production rate from Well B with and without constraint on water production rate shows that 7337.432STB/day of oil was produced without any constraints on water production while 7373.479 STB/day of oil was produced with constraint on water production and Well A, 280.6693 STB/day of oil was produced without any constraints on water production while 3.266503 STB/day of oil was produced with constraint on water production. For the injection of 4MMscf/day of gas with a constraint of 1800STB/day on water production, results reveals that a total gas lift rate of 3.723612MMscf/day was required to lift a total oil rate of 7484.669STB/day. Therefore, out of the 4MMscf/day of gas available, 3.723612MMscf/day should be allocated to the network to optimized production.

Keywords: Gas lift; Production rate; Water Production; Maximize; Constraint; Optimizer

1. Introduction

Artificial lift technologies are a major topic for production system design. They supply energy to fluid in the production well to restore and improve upon reduced productivity in the reservoir, and are used to facilitate or accelerate oil production. Gas lift is the most preferred artificial lift when injection gas is available; compressed gas is injected into the production well to allow oil to flow from the reservoir to the surface. Continued gas injection reduces the average fluid density and bottom-hole pressure in the production well, which allows the oil to flow to the surface. The gas lift method offers easy installation, economic feasibility, and effectiveness for large fields. However, a stable supply of gas should be ensured because the increased fluid production includes large amount of gas, which increases the bottom-hole pressure, and reduces oil production. Thus, the gas injected into each oil well should be allocated appropriately. Oilfields where production is already underway have operating and facility constraints with respect to the capacities of the compressors and separators; thus, they require allocation optimization (Buitrago *et al.,*1996).

The daily available lift gas are often constrained due to facility conditions and is prone to variation. In addition, operating conditions and handling facilities can dictate compressor deliverability and separator limits during production, while poor allocation of the available lift gas can be economically costly, leading to over-constrained or overdesigned facilities (Camponogara and Nakashima, 2006). As such, an optimal lift gas allocation is desirable to ensure that the best possible oil production or profit can be realized (Rashid, 2010; 2011).

In order to resolve the various issues related to gas lift allocation, Nishikiori *et al.,* (1989), Fang and Lo (1996), Dutta-Roy and Kattapuram (1997), Dutta-Roy *et al.*,(1997) and Wang *et al.,* (2002) applied optimization techniques based on

* Corresponding author: Nyelebuchi Amadichuku

derived functions. However, such techniques are limited to locally optimal solutions or do not ensure stable convergence for huge production systems with strong non-linearity. To overcome such restrictions, Martinez *et al.,* (1994), Stoisits *et al.,* [1994; 1999], and Posenato and Rosa (2012) applied genetic algorithms, which are effective for global optimization. This study optimized gas lift while considering constraints on the gas lift system.

2. Methodology

2.1. Simulator and Data

PIPESIM steady state multiphase flow simulator and the data on Casing design, tubing, completion, Flow line, Gas lift port, and Fluid properties presented in Table 1 to Table 6 were used in this work.

Table 1 Casing design data

Parameters	**Well A**	**Well B**
Casing bottom measured depth (ft)	5000	5500
Casing ID (inch)	5.984	5.984
Casing wall thickness (inch)	0.5984	0.5984
Roughness	0.001	0.001

Table 2 Tubing data

Parameter	**Well A**	**Well B**
Tubing Bottom Depth (ft)	4500	5000
Tubing ID (inch)	2.992	2.992
Tubing wall thickness (in)	0.5	0.5
Roughness	0.001	0.001
Packer measured depth (ft)	4300	4700

Table 3 Completion data

Variable	**Well A**	**Well B**
Fluid entry	Single point	Single point
Completion measured depth (ft)	5000	5500
IPR model	Well PI	Well PI
Reservoir pressure (psia)	1500	1600
Reservoir temperature (°F)	190	190
IPR Basis	Liquid	Liquid
Productivity index, STB/(d.psi)	5	2

Table 4 Flowline data

Name	**Length (ft)**	**Elevation (ft)**	**Diameter (in)**	**Roughness (in)**	**Wall thickness (in)**
Well-A Flowline	4000	0	4	0.001	0.5
Well-B Flowline	3000	0	4	0.001	0.5
CPF Flowline	2000	0	6	0.001	0.5

Table 5 Gas lift port data

Properties	**Well A**	**Well B**
Injection measured depth (ft)	4260	3850
Injection gas rate (MMscf/d)	0.45	0.95
Gas specific gravity	0.71	0.71

Table 6 Fluid properties

Properties	Well A	Well B
Water cut (%)	65	20
GOR (SCF/STB)	200	200
Gas specific gravity	0.72	0.74
Water specific gravity	1.02	1.02
API	32	28

2.2. Simulation Procedure

A wellbore model was built with PIPESIM in the well centric workspace and exported to the network canvass for the development and linked to the flowlines and coupled to the surface facilities. Downhole tubulars (casing and tubing strings) were added to the well template for both wells using the data in Table 1 and 2. The single option was selected for both the overall heat transfer coefficient and the ambient temperature input in the thermal gradient section and a value of 2-Btu/h/ft^2/°F and 60°F were entered for the overall heat transfer coefficient and the ambient temperature respectively. The geometry profile, fluid entry and middle measured depth were entered in the completion section. The Vogel method IPR model was selected and the reservoir pressure, temperature and productivity index were entered and liquid phase selected as the IPR basis. A black oil fluid model was created using the data shown in Table 4 and the completed well models (Well A and Well B) were exported to the PIPESIM network canvass. Gas lift valve was added to the well model using the gas lift port data in Table 5.

The wellbore model and the flowline model were coupled with the PIPESIM workspace switched from the well-centric workspace to the network-centric workspace. The network model which consists of two wells (Well A and Well B) that produced together into a single manifold. And a commingled streams delivered to a single delivery point (Central Processing Facilities (CPF)) were added to the PIPESIM network interface.

Then, the flowline connector was used to connect the wells (Well A and Well B) to the manifold and the manifold to a sink node representing the central processing facility (CPF) and to the two junction nodes. The flowline properties (length, elevation) were define using the data in Table 4 and used in the development of Well-A-Flowline, Well-B-Flowline and CPF-Flowline.

The PIPESIM Network simulation task was run to the production from the network of gas lifted wells with a total gas lift rate of 1.4 MMscf/d. The Network Optimizer task was run with any constraint on water production to maximize the oil production when allocating a total gas lift rate of 4 MMscf/d to the two production wells. Also, with the optimization task, a constraint of 1800 STB/day on water production was included while still allocating a total gas lift rate of 4 MMscf/d to the two production wells. The simulation workflow is presented in Figure 1

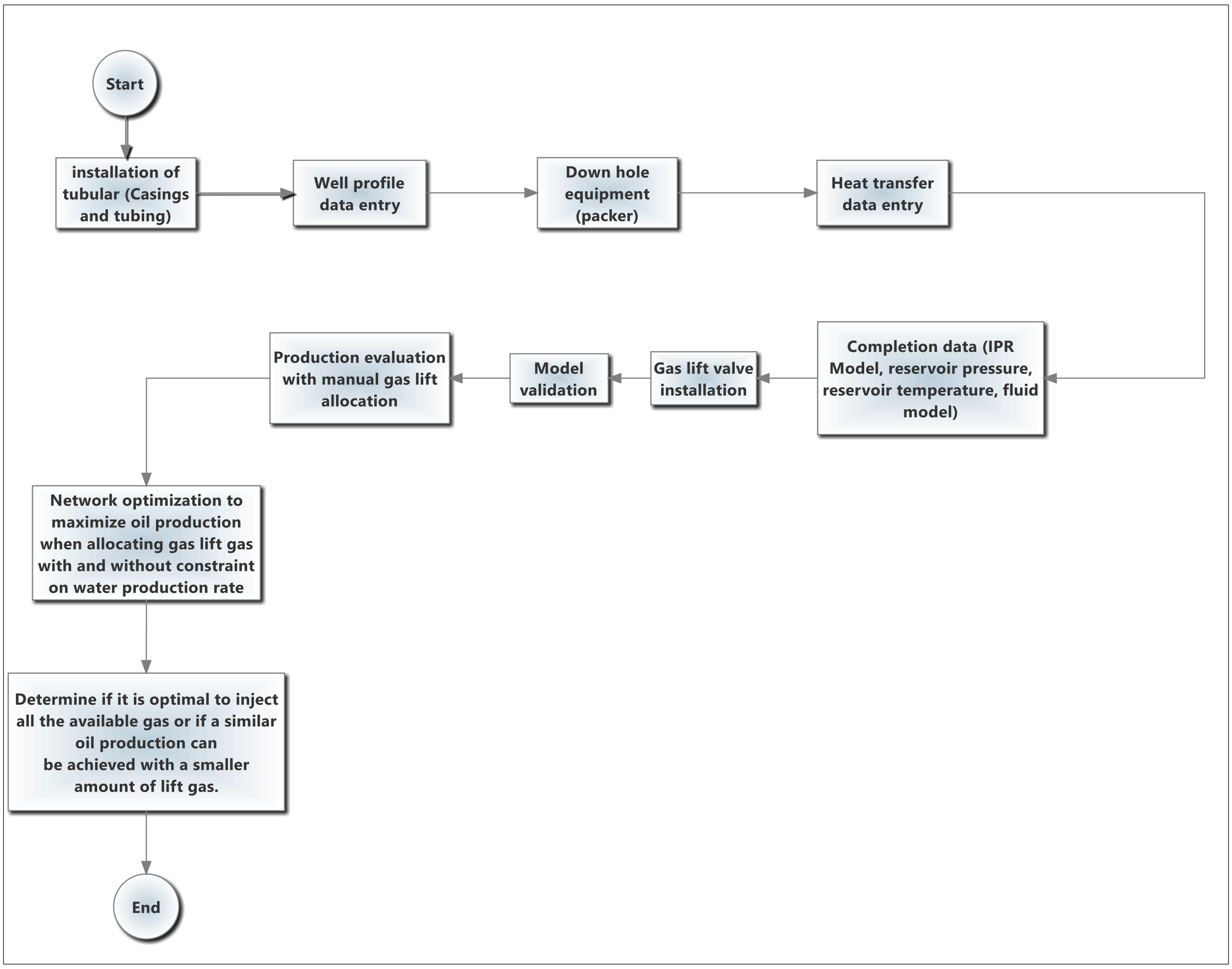

Figure 1 Simulation workflow

3. Results and discussion

3.1. Network optimization with no constraint on water production

The results for the optimization when a total gas lift rate of 4MMscf/day was allocated to the two production wells (Well A and Well B) with no constraint on water production rate is presented in Table 7.

Results shows that without any constraint on water production rate, a total oil rate of 7618.102STB/day, gas rate of 5.525699MMscf/day and water rate of 2355.601STB/day was obtained at the CPF. Comparatively, the oil, gas and water rate obtained at the CPF with no constraint on water production rate when 4MMscf/day of gas was assigned to the production wells was higher than that obtained with the network simulation task for which 1.4MMscf/day of gas was manually assigned to the two production wells. A percentage change in oil rate of 1.078777% for allocating 4MMscf/day to the network out of which 1.8506MMscf/day goes to Well A and 2.149352MMscf/day goes to Well B was observed. A percentage change in water rate of 4.031755% and a percentage increase in gas rate of 90.01764% were also obtained.

Table 7 Optimization with no constraint on water production

Well	Gas lift rate (MMscf/d)	Total gas rate (MMscf/d)	Oil rate (STB/day)	Water rate (STB/day)
Well A	1.8506	1.908698	280.6693	521.243
Well B	2.149352	3.617001	7337.432	1834.358
Total	3.999952	5.525699	7618.102	2355.601

3.2. Gas lift performance curves for Well A and B with no constraint on water production

Figure 2 shows the gas lift performance curve for Well A and it reveals that an optimum gas lift injection rate of 1.8506 MMscf/day was required to maximize oil production rate from Well A. An oil production rate of 280.669 STB/day was obtained from Well A when 1.8506 MMscf/day of gas was injected.

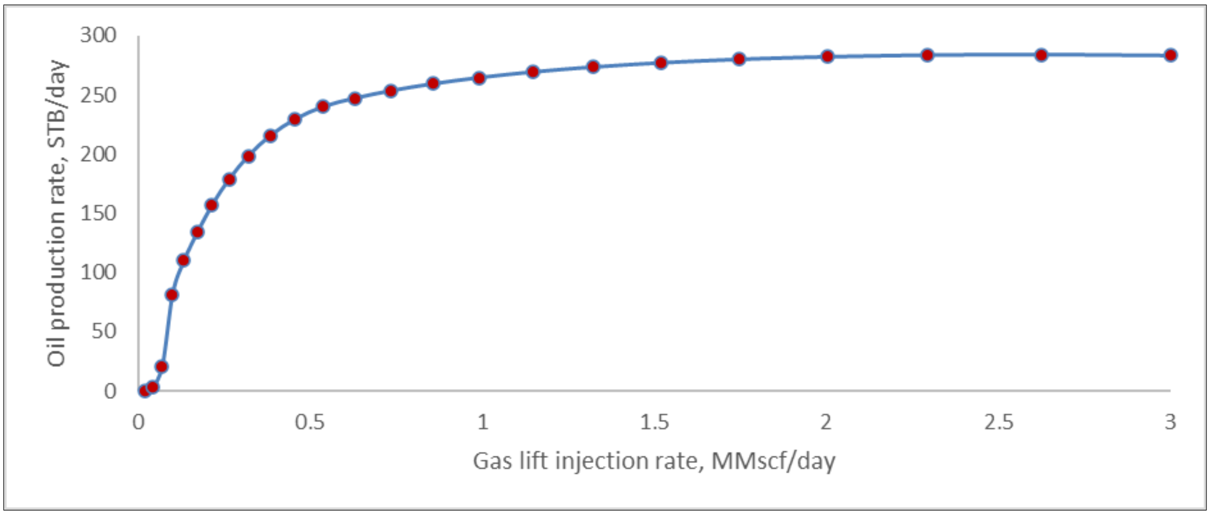

Figure 2 Gas lift performance curve for Well A with no constraint on water production

Figure 3 shows the gas lift performance curve for Well B and it is observed that an optimum gas lift injection rate of 2.149352MMscf/day was required to maximize oil production rate from Well B. An oil production rate of 7337.4 STB/day was obtained from Well B when 2.149352MMscf/day of gas was injected.

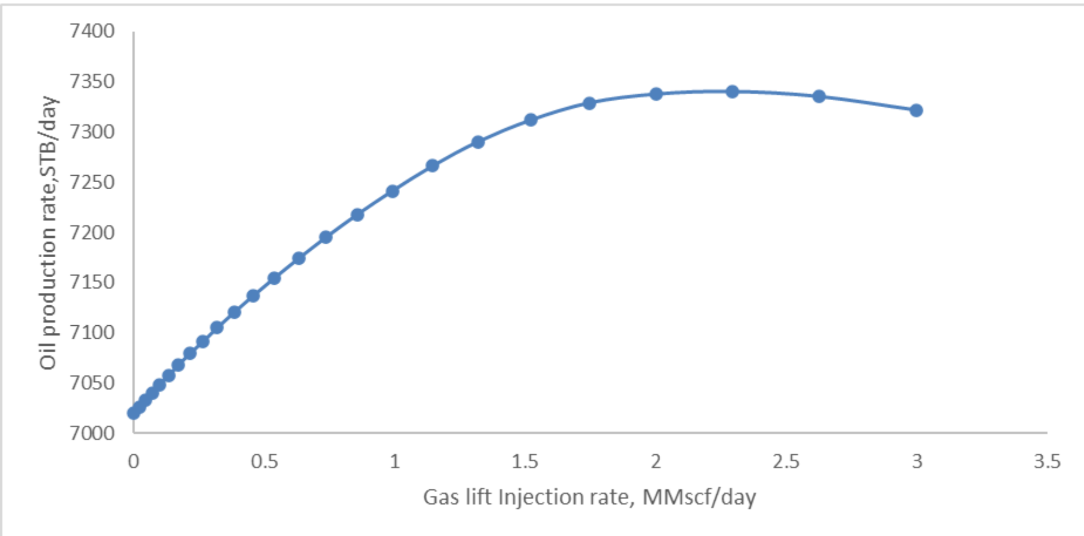

Figure 3 Gas lift performance curve for Well B with no constraint on water production

3.3. Network optimization with constraint on water production capacity

The water handling capacity at the delivery point (CPF) was 1800 STB/day, while the gas distribution determined in the previous task with no constraint lead to 2355.601 STB/day of water production. The result of a total gas lift rate of 4 MMscf/day allocated to the two production wells with constraint on water production rate is presented in Table 8. Result reveals a percentage decrease of 2.123591% on oil production rate as a result of a constraint of 1800 STB/day on water production and a percentage decrease of 18.32229% in water production rate as a result of a constraint of 1800 STB/day of water. A percentage change of 55.40342% in gas rate was observed.

Table 8 Optimization with constraint on water production capacity

Name	Gas lift rate (MMscf/day)	Total gas rate (MMscf/d)	Oil rate (STB/day)	Water rate (STB/day)
Well A	0.04332	0.04430835	3.266503	6.066362
Well B	3	4.474812	7373.479	1843.37
Total	3.04332	4.51912	7376.746	1849.436

The gas lift performance curve for Well A is presented in figure 4. Result reveals that with a constraint of 1800STB/day of water at the CPF, an optimum gas lift injection rate of 0.04332MMscf/day was required to maximize production rate Well A. An oil production rate of 3.266503 STB/day was obtained from Well A when 0.04332 MMscf/day of gas was injected. A comparison of the oil production rate from Well A with and without constraint on water production rate shows that 280.6693 STB/day of oil was produced without any constraints on water production while 3.266503 STB/day of oil was produced with constraint on water production.

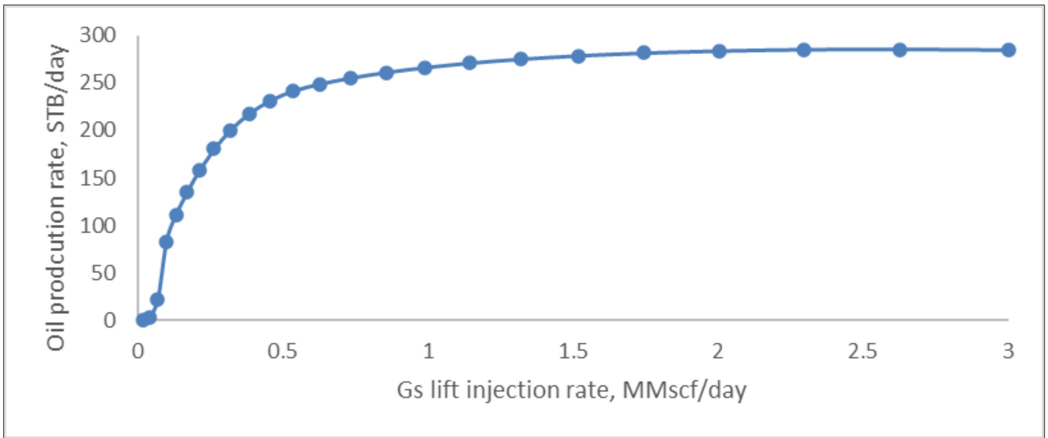

Figure 4 Gas lift performance curve for Well A with a constraint of 1800STB/day on water production

The gas lift performance curve for Well B after a constraint of 1800STB/day of water was placed on water production at the CPF is shown in figure 5. Result reveals that an optimum gas lift injection rate of 3 MMscf/day of gas was required to maximize oil production from Well B. An oil production rate of 7199.921STB/day was obtained from Well B when 0.7236126 MMscf/day of gas was injected. A comparison of the oil production rate from Well B with and without constraint on water production rate shows that 7337.432STB/day of oil was produced without any constraints on water production while 7373.479 STB/day of oil was produced with constraint on water production.

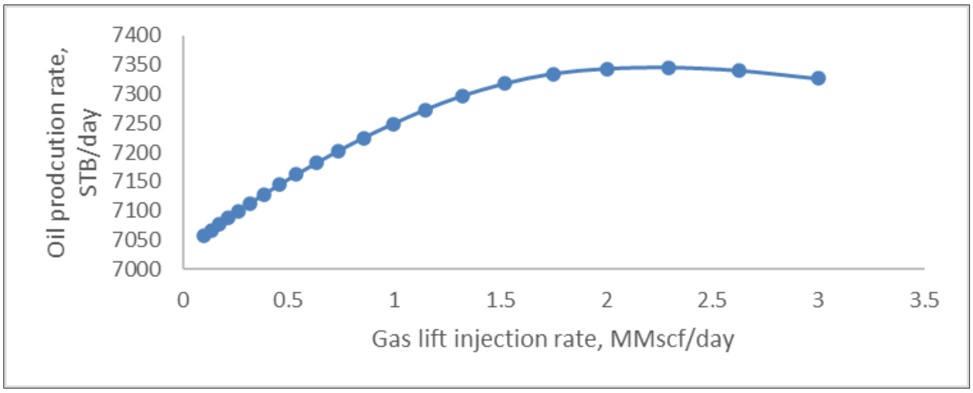

Figure 5 Gas lift performance curve for Well B with constraint on water production

For the injection of 4MMscf/day of gas with a constraint of 1800STB/day on water production, results reveals that a total gas lift rate of 3.723612MMacf/day was required to lift a total oil rate of 7484.669STB/day.

4. Conclusion

This work optimized gas lift injection rate based on the allocation of an optimal amount of gas to a network of wells with water handling capacity constraints at the Central Processing Facilities (CPF) to improve the oil production rate. The PIPESIM Network Optimizer was used to overcome the restrictions of locally optimized solutions during optimization, and the oil production rate was estimated based on the optimized gas lift allocation.

The following conclusions were drawn from the study:

- The optimum gas lift injection rate varies for the wells with well A having the least and well B the highest with no constraint on water production.
- The oil, gas and water rate obtained at the central processing facilities with no constraint on water production rate for higher gas rate to the production wells using PIPESIM network optimizer simulation task was higher than that obtained with the manual network simulation task for the lower gas rate for the two production wells.
- There was a higher oil production rate with constraint on water production than without constraint on water production.

Compliance with ethical standards

Disclosure of conflict of interest

No conflict of interest to be disclosed.

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