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# Gaslift Optimization to Improve Well Performance: A Case Study of X Field in Niger Delta

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***Abstract*-** The earliest drilled wells of the Niger-Delta have depleted, hence the need for support. Also associated gas utilization is still an issue in the Niger-Delta. Gas-lift rate optimization; Operating a gas-lift under low or high gas-lift injection rate has some disadvantage. The aim of this research is to optimize oil production by: developing a model for gas lift volume requirement, for increasing oil production, extending life of artificial lift system, reducing operating cost and lowering capital expenditure. A comparative cost analysis was done between gas-lift and Electric Submersible Pumps method to choose the most economical lift method for the Niger-Delta region. The profitability indicator such as Net Present Value (NPV) and Profitability Index (PI) on Investment were used to select the economic service-producing investments. A plot of the oil production rate for various gas injection rates was generated and it was seen that the maximum oil rate for the technical optimum is approximately 522 STBO/day and that injection at a rate greater than 360 MSCFD results in very little increase in oil rate. Also, it was seen that the maximum oil rate for the economic optimum is approximately 490 STBO/day and that injection at a rate greater than 250 MSCFD might not be economically viable, depending on the cost to compress the gas and the income from the sale of the oil.

***Keywords*-** *Gaslift, Optimisation, Well Performance*

## I. Introduction

Gas lift is a method of lifting fluid where relatively high pressure (250 psi minimum) gas is used as the lifting medium through a mechanical process. The need for artificial lift is required when the pressure of the well is not enough as to maintain the oil production with satisfactory economic return. This situation is typical in mature oil field where increasing water cut or decreasing reservoir pressure eventually causes well to cease natural flow. In order to solve this problem, two different approaches are generally used. First approach is to increase bottom-hole flowing pressure with the aid of bottom-hole well pumping. Second one is to reduce fluid column density in the wellbore by injecting compressed gas which is called gas lift [1]. In a typical gas lift system, compressed gas is injected through gas lift mandrels and valves into the production string. The injected gas lowers the hydrostatic pressure in the production string to re-establish the required pressure differential between the reservoir and wellbore thus causing the formation fluids to flow to the surface [1].

Production enhancement refers to the practice of making changes or adjustments in order to produce the limit (maximum). The ultimate goal of virtually all efforts spent on modelling a petroleum field is to devise an optimal strategy to develop, manage, and operate the field. For some petroleum fields, optimization of production operations can be a major factor in increasing production rates and reducing costs. While for single well or other small systems simple nodal analysis may be adequate, large complex systems demand a much more sophisticated approach to predict the response of a large complicated production system accurately and to examine alternative operational scenarios efficiently [2].

Well performance analysis is a combination of various components of oil or gas wells in order to predict flow rates and to optimize the various components in the system. A variety of issues are frequently classified as either inlet/outlet issue or downhole issue.

When natural lift begins to fall or decline, it can no longer be relied upon to get hydrocarbons to the surface and surface facilities. When this happens overtime, the well production stops and the well is said to be dead. When there are commercial quantities of hydrocarbons trapped in the well, an alternative is used to bring the well back to production. This is where artificial lift can supplement natural lift.

Sucker Rod Pump, Gas Lift and Electric Submersible Pumping (ESP) are the most common artificial-lift systems, but hydraulic and progressing cavity pumps are also used.

### A. *Reasons for gas-lift*

Gas lift installations absolutely can handle the flowing conditions throughout the life of the well. Changing reservoir pressures, water cuts, and formation gas rates can be taken into account with the initial design. And because gas lift equipment is durable, portable and has few moving parts, it offers a longer life compared to other forms of lift. It possesses low installation and maintenance cost. Can control production rates at the surface, suited for deviations and horizontal well bores and produced sand has little effect on it [3].

### B. *Facts about Gas-lift*

Gas lift can produce almost any oil or gas well that requires artificial lift, Gas lift is limited only by the availability of gas. Gas lift can unload and kick-off wells that flow on their own. Gas lift can increase the rate of flowing wells. Gas lift can increase the velocity in a gas well to ensure produced fluids are recovered at the surface. Large tubing or annular flow gas lift can be utilized to produce extremely high rates. Intermittent gas lift can produce wells with low production rates or low reservoir pressure. Side pocket gas lift mandrels can be installed with dummy valves in the initial completion when the well may flow on its own. Later, when the well has loading problems, gas lift valves can be installed with wireline to enable the gas lift system [3].

### C. Gas Lift Flow Process

Gas lift flow process is a type of artificial lift process that seem same as the natural flow process. In both flow processes, Reservoir Pressure is their driving force. Reservoir pressure drives fluid into the wellbore, to the surface wellhead and into the surface separator. The process and the wellhead pressure constrains have significant impact on bottom hole flowing pressure and the production rate. The tubing and the flow line sizing changes mixture velocity, flow patterns and pressure loss due to the quantity of gas flowing with the liquid.

Artificial lift system is a method which lowers the producing bottom-hole pressure (BHP) on the formation of a well in order to get a higher production rate from the well. This can be done with a positive-displacement down-hole pump, for example, a beam pump or a progressive cavity pump (PCP) to lower the flowing pressure at the pump intake. It also can be done with a down-hole centrifugal pump, which could be a part of an electrical submersible pump (ESP) system. Also low bottom-hole flowing pressure and high flow rate can be achieved with gas lift, which lower the density of the fluid in the tubing and expand gas to lift the fluids. Artificial lift can be used to generate flow from a well in which no flow is occurring or used to increase the flow from a well to produce at a higher rate. Most oil wells require artificial lift at some point in the life of the field, and many gas wells benefit from artificial lift to take liquids off the formation [4]. Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced hydrocarbon fluids to the surface. The produced hydrocarbon fluid can be oil, water or a mix of oil and water, typically mixed with some amount of gas.

As it is well known, there is a wide range of artificial lift systems available for oil and gas application. The requirement to eliminate and select the best artificial lift method and strategy for the life of the well cannot be over-emphasized. Yearly, the industry loses billions of dollars in both revenue loss and lift conversion or inefficient lift performance and failure expenses due mainly to improper artificial lift selections [5]. Ayatollahi *et al*. [6] used PVT data combined with fluid and multiphase flow correlations to optimize the continuous gas lift process in Aghajari oil field. From actual pressure and temperature surveys and determining the point of injection, a gas lift performance curve was constructed. In order to determine the optimal gas lift condition, nodal analysis was used to determine optimum injection depth, optimum wellhead pressure, optimum production rate and minimum injection gas volume as well as the appropriate valve spacing. Camponogara and Nakashima [7] developed a dynamic programming (DP) algorithm that solves the profit maximization problem for a cluster of oil wells producing via gas lift, with multiple well performance curves (WPCs) and constrained by the amount of lift gas available for injection. Redden *et al*. [8] calculated optimum distribution of available lift gas for a group of gas lifted wells based on each wells contribution to the profit of the system. Coltharp and Khokhar [9] devolved a computer gas lift surveillance and gas injection control system installed in Dubai. In 1990, Edwards established a gas-lift optimization and production allocation for manifold subsea wells [10].

A programmable logic controller was used by Lemetayer and Miret [11] to increase the gas-lift efficiency with an increase in oil production and decrease in gas injection. In 1994, Everitt showed that the gas-lift optimization efforts in a large mature field could reduce the gas-lift requirements by 50% [12].

Buitrago *et al.* [13] used a global optimization technique for determining the optimum gas injection rate for a given group of wells in order to maximize the total oil production rate for a given total amount of gas without restriction in the well response and the number of wells in the system. Ghoniem *et al.* [14] described the construction of using general optimization allocation models for Khafji field in the Arabian Gulf.

When reviewing the performance of an existing gas lift system or investigating the feasibility of a potential gas lift system the following rules were observed by Everitt, in 1994 [12]:

i. The success of any gas lift system depends on an adequate and reliable source of quality lift gas throughout the period when gas lift is required.

ii. The gas injection point should be as close as possible to the top of the completion interval.

iii. Gas lift systems should operate with minimum back pressure at the wellhead.

iv. Lift should be as stable as possible.

v. All gas lift system should address future, as well as present operating conditions.

vi. Overly conservative design assumptions should be avoided- design factors should reflect the availability and quality of design data.

vii. Lift gas availability should be optimized to enable the system to operate near continuously in the most profit-able configuration (example, minimize compressor downtime).

viii. Gas lift systems should be designed with all modes of operation in mind.

ix. Surveillance and control should be considered as an integral part of any system. The ability to control gas lift distribution is essential for efficient gas lift operation.

## II. Comparative Cost Analysis

Before making decision on which method of artificial lift to be used, a thorough economic analysis needs to be done. It is the profitability of a project that has to be the final decision criteria. In this work, a study is carried out for the economic comparison of the wells with same production design rate considering two artificial lift methods mostly common in Niger-Delta fields i.e., Gas-lift and ESP (Electric Submersible Pump). Selecting the best equipment for production operations will bring about maximum benefit and good return on investment.

The profitability indicator such as NPV, (Net Present Value) and PI, (Profitability Index) on Investment is used to select the economic service-producing investments such as the Gas-lift and ESP equipment.

The current oil price of bonny-light as at now is $78.40 per barrel. The targeted oil volume to be produced is assumed to be 1000 bbls/day. The current interest rate in Nigeria as of now is 14%. The estimated cost for six years is tabulated as shown in Appendix 1

The equations for the estimation of NPV and ROR are given below

$$NPV = NCF \times \left[\frac{(1+i)^t - 1}{i\,(1+i)^t}\right] - \text{Initial Investment} \quad (1)$$

Where, NCF =Annual Revenues – Annual Expenses

Annual Revenue = Oil price x Targeted production rate

NCF = Net Cash Flow, $

NPV = Net Present Value, $

i = Interest rate, fraction/percentage

t = Time, years

$$PI = 1 + \frac{NPV}{PV\ of\ Capital\ Investment} \quad (2)$$

Where,

PI =Profitability Index, dimensionless ratio

PV= Present Value, $

Appendix 2 shows the expected cash flow for the investment alternatives. The initial investment is the cost of the equipment and the installation cost of equipment. The annual revenue is the product of current oil price and production target rate, while the annual expenses comprises of cost of maintenance, water treatment, power and energy requirement, etc. NPV and PI is obtained by applying Equation 1 and Equation 2

From Appendix 2, the profitability indicators show that both equipment are economical, but Gas-lift method is more profitable than ESP method. Since the investments are mutually exclusive, only one is selected. The NPV and PI of each methods shows that Gas-lift should be selected for the optimization of the well.

## III. RESULT AND DISCUSSION

There is an optimum injection gas volume for a well that will result in a maximum liquid production rate. If this volume of gas is not available, the well will produce at a lower rate. If several gas lift wells in a field are utilizing a limited volume of injection gas, nodal analysis can be used to determine the optimum volume of gas to allocate to the various wells. The performance of a gas lift well can be analyzed using system nodal analysis.

The intersection of the inflow and outflow curves gave the liquid production rate corresponding to each injected Gas Liquid Ratio. The required volume of gas to be injected is calculated and a plot of liquid production rate versus gas injection rate is constructed.

Fig. 1 shows the Inflow performance relation and curve respectively. The inflow and six outflow curves are plotted on Fig. 2. The producing capacities for the various injected Gas Liquid Ratios are read from the intersections of the inflow and outflow curves.

A plot of the oil production rate for various gas injection rates is shown in Fig. 3. It can be seen that the maximum oil rate for the technical optimum is approximately 522 STBO/day and that injection at a rate greater than about 360 MSCFD results in very little increase in oil rate.

As lift gas volume gets to the maximum liquid rate, the benefits derived from a less dense fluid column is outweighed by friction effects - both in the tubing, and the flow line. Increasing lift gas rates further will have little benefit on well production, and if the lift rate is increased too far then the well will begin to produce less fluid.

As the maximum liquid rate is approached, a large increase in gas injection rate is required to obtain a small increase in liquid production rate. Also, Fig. 3 shows that the maximum oil rate for the economic optimum is approximately 490 STBO/day and that injection at a rate greater than about 250 MSCFD might not be economically viable, depending on the cost to compress the gas and the income from the sale of the oil. The economic optimum gas injection rate may be considerably lower than that required to obtain the maximum liquid rate.

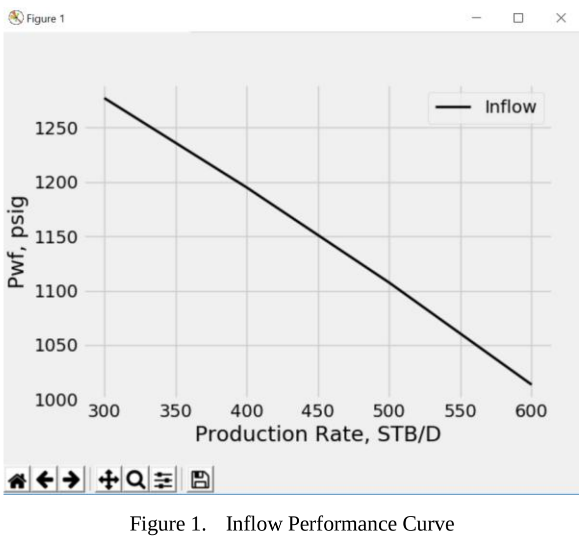


Figure 1. Inflow Performance Curve

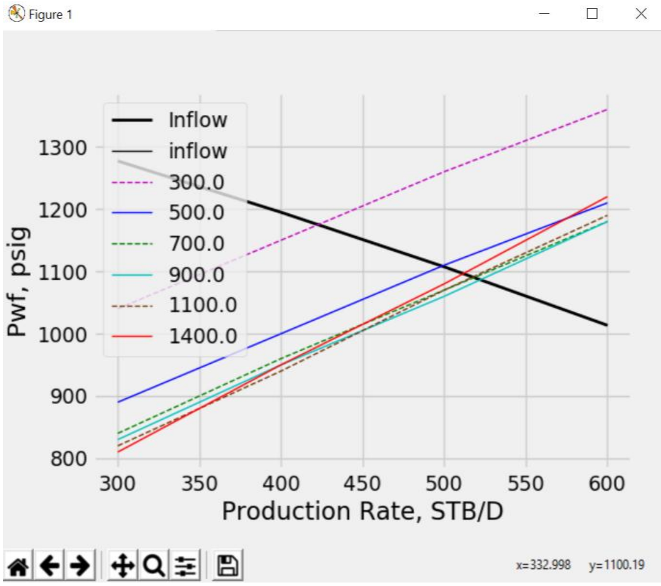


Figure 2. IPR/VLP Curve

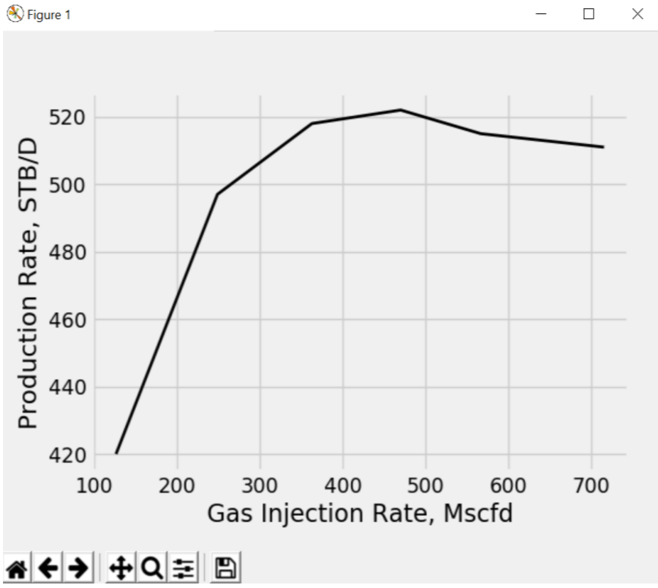


Figure 3. Gas volume required

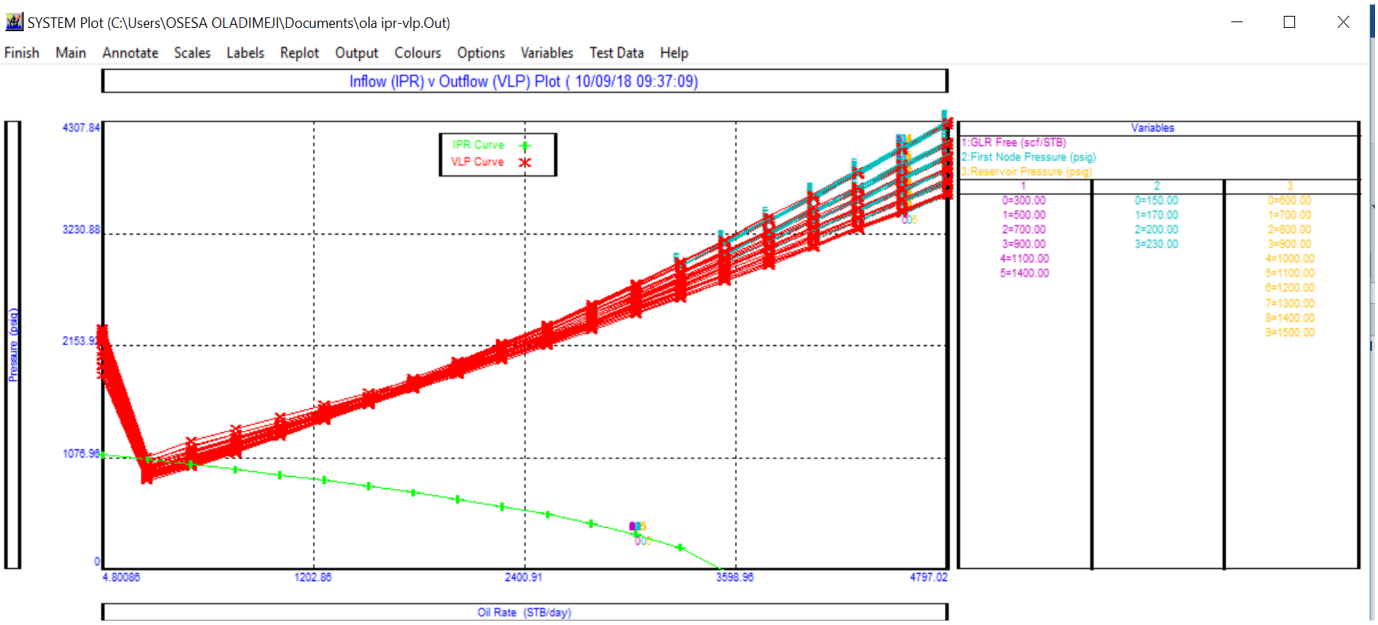


Figure 4. IPR/VLP Curve (Prosper)

### *A. Model Validation*

The model was validated with the same data by using PROSPER; a petroleum expert tool to see the deviation from the already established tool. This is as shown in Fig. 4 above.

## IV. Conclusion

From the model developed, based on the field history, the following observation were made. A software was developed as a quick estimate for the production capacity of the well. The following observation were made:

1. A well will produce at a lower rate, if several gas-lift wells in a field are utilizing a limited volume of injection gas, the sensitivity analysis was used to determine the optimum volume of gas to allocate to the well technically.
2. Based on the economic analysis and operations point of view couple with the fact that an operating gas compression station is already available in the field, gas lift was recommended as a best option and economically

depending on the cost of compressing the gas and the revenue from the sale of oil.

3. It was observed that the well head pressure has a large influence on the gas lift performance. The lower the well head pressure the more volume of oil is produced.
4. A total system analysis is also required to evaluate the effects of other factors on production system especially downstream of the Christmas tree to the sale point.
5. Planning for gas lift should be made compulsory and done alongside with drilling plan, and installation of gas lift valves done after well perforation, to reduce cost, minimize non-productive time, and for effective tubing size selection.
6. Gas-lift performance while optimizing production should be monitor regularly, by both field operators and other engineers.

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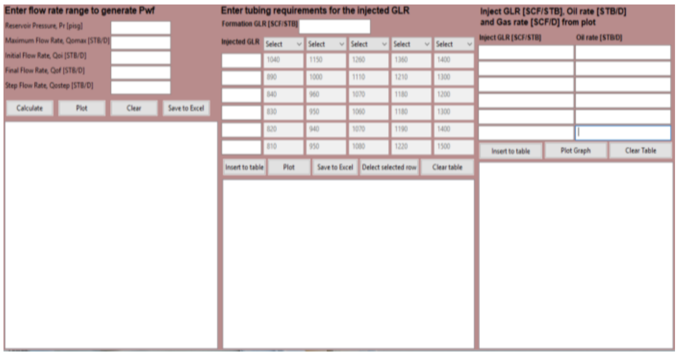
Appendix 1: Gas-lift and ESP Estimated Cost for six years

| For six years | Gas Lift | ESP |
|---|---|---|
| Item | (Cost, $) | (Cost, $) |
| Power/Energy Requirement | 1,478,516 | 5,043,032 |
| Installation | 70,000 | 100,000 |
| Equipment | 300,000 | 250,000 |
| Running cost | 18,000,000 | 18,000,000 |
| Maintenance | 2,400,000 | 3,200,000 |
| Water treatment | 2,100,000 | 2,100,000 |
| Sum | 24,348,516 | 28,693,032 |

Appendix 2: Gas-lift and ESP Cash Flow

| | Gas-Lift | ESP |
|---|---|---|
| Initial Investment, $ | 370,000 | 350,000 |
| Annual Revenues, $ | 28,616,000 | 28,616,000 |
| Annual Expenses, $ | 23,978,516 | 28,343,032 |
| Investment Life, Years | 6 | 6 |
| NCF | 4,637,484 | 272,968 |
| NPV | 28,117,380.16 | 1,599,770.16 |
| PI | 76.99 | 5.57 |

Appendix 3: OOC Software User Interface

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