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Analytical Simulation for the Improvement of Oil Well Productivity Using Artificial Gas Lifting Techniques

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ABSTRACT: *A well simulation analysis was done using integrated production modeling (IPM) software (PROSPER) to determine the productivity of two wells. The simulation includes the well properties and a detailed description of the reservoir and vertical lift performance of the wells under investigation. The process was segmented into two phases. Phase -1 comprises of simulating a well using Pressure, Volume, Temperature (PVT) data, Inflow Performance Relationship (IPR) data, and surface production data. While phase-2 includes conducting Well analyses based on the different operating conditions prevalent in the field. Each constituent of the producing Well for the study was evaluated using a well-analytical approach. The bias in this procedure is to identify potential challenges in the production mechanisms causing flow restriction which adversely limit the well from achieving its maximum producing potential flow proportion. Three operational conditions were selected for the reservoir simulation, which include; varying the tubing size, varying gas injection rate, and reduction of the tubing head pressure. The simulation and analysis of the wells (22T and 19L) indicate Well Productivity as a function of Tubing-head pressure, while the reduction in the Tubing-head pressure causes an increase in production rates. However, the variation of the tubing sizes did not show a significant increase in Wells 22T and 19L. This is potentially due to the well's high reservoir pressure, which required no artificial lift application at this instant but certainly in the future.At the conclusion of the analysis done on the two selected producers Wells under investigation, the results show that a gas artificial lift will certainly enhance well Productivity in the selected field.*

KEY WORDS: artificial gas lift, simulation, productivity, oil and gas production, oml 42, gas injection rate, water-cut.

INTRODUCTION

Primarily, the objective of any Exploration & Production company is to find oil and gas fields with sufficiently large reserves to maximize profits. This business objective is largely dependent on reservoirs having relatively high pressures capable of producing hydrocarbon over a long period of time. Wherever, such high-pressure reservoirs are discovered, hydrocarbons are produced without the investment in further enhanced oil recovery mechanism such as artificial gas lift system to extract reservoir fluids to the surface production equipment.

However, with continuous production of hydrocarbon fluids from the reservoir, there will be obviously significant decline in reservoir pressure, that will make it insufficient to extract reservoir fluids to topside modules, and therefore, there will be need for alternative enhance Oil recovery (EOR) methods to continue further production of hydrocarbon from the reservoir.

Wells that are flowing naturally are wells that reservoir pressures are sufficient to produce oil at a commercial rate without requiring an artificial lift system. Natural reservoir energy is a function of pressure and gravity which is the fundamental driving force in transporting fluids from the underground reservoir to the surface in wells that are naturally flowing without artificial drive mechanism.

Significant research over the years have shown that there are several causes of low Productivity in naturally flowing reservoir wells. These causes include reservoir damage regarded as skin effect around the wellbore, thief zones in the formation, plugged/ineffective perforations, high water-cut, low reservoir temperature in offshore locations, low formation permeability, challenges during well completions, restrictions in the wellbore, etc. Consequently, Diagnostic analysis is required to troubleshoot a low oil producing well, analyse the reservoir and well parameters that are responsible for the low productivity which will enable the reservoir engineers to select the best artificial lift techniques required for maximum oil production.

Artificial lift therefore refers to using production mechanical devices or methods in the case of gas lifting, to increase the flow of hydrocarbon in producing oil and gas wells. In the early stages of production, the well may be capable of producing hydrocarbon fluids through natural energy. However, in the later stages of the well life, it produces only a tiny portion of the desired well fluids naturally due to dropping reservoir pressure. A suitable means of artificial lift must be installed in order to maintain the required bottom hole pressure that will be sufficient to lift the hydrocarbon to the surface at the later stages of the well productive life. Therefore, this research work is to investigate the optimum gas lift injection pressure desirable to lift subsurface hydrocarbon fluids in low producing wells within the field under investigation while utilizing the gas lift method as the potential artificial lift techniques for the field, in other to ensure the sample wells are producing within the desirable economic limits of 1000STB/D.

LITERATURE REVIEW

The major challenge of the present-day energy sector is to meet the constantly growing world energy demand. The world energy forecasts still show that hydrocarbon production will remain the foremost energy source in the coming decades (Pankaj *et al,* 2018). In other words, there is need for the oil and gas industry to provide more oil and gas than it currently producing, though the potential for discoveries of new fields is somewhat reduced due to global financial challenges and divestment into renewable energy. In addressing the global energy challenges, it will be crucial to continuously optimize and increase the recovery factor of currently existing oil and gas production fields. Thus, without any doubt, the use of Artificial Gas Lifting (AGL) method will be vital to achieving this objective as its potentials in increasing production is well established in the industry.

Some of the most popular artificial lift techniques include sucker rod pumps, electric submersible pumps, and lifts. Nevertheless, these methods are more frequently used in Arabian countries where the natural reservoir drive mechanism is very low (Brown, 1982).

However, researchers such as (Kermit *et al*, 2006), have argued that the most widely used artificial lift technologies include intermittent gas lift and continuous gas lift, and pump assisted (including plunger lifts, bean/rod pumps, hydraulic jet pumps, progressive cavity pumps and electrical Submersible pumps), that have been in existence for decades.

Characteristically, more than one lift method can be in use for a given oil field, and selecting the most suitable type of artificial lift for a well or group of wells can be difficult or easy depending on the prevailing production conditions in the field, (Kermit *et al*, 2006). However, the most vital determinant in selecting a lift method is the enhanced flow rates achievable by each method in a given field that is key (*Brown*,1982).

Inflow Performance Relationship

Inflow performance relationship (IPR) could be defined as the Well-flowing bottom hole pressure (P_{wf}) as a function of production rate (q) over a practical range of operating conditions (Muskat *et al*, 1942). Also, IPR of a well is the relationship between the production rate into the wellbore and the flowing bottom hole pressure (Jahanbani *et al*, 2013). Hence, IPR is vital in understanding productivity outputs in an oil and gas producing reservoir. Evinger and Muskat (1942), showed a curved relationship between flow rate and pressure when a two-phase flow occurs in the reservoir.

Productivity Index

Oil and gas well productivity index (PI) is regarded as a measure of the well to produce quantifiable amount of hydrocarbon fluids. It is denoted by the symbol (J) in most scholarly text. The productivity index is also regarded as the ratio of the total flow rate to the pressure drawdown in a well.

In most water-free oil production scenario, the productivity index is mathematically expressed as:

$$J = \frac{q}{P_R - P_{wf}} = \frac{q}{\Delta P} = \frac{2\pi kh}{\mu B_o} \frac{1}{In\left(\frac{r_e}{r_w}\right) - \frac{2}{4} + S} \text{---(1)}$$

Thus, production well test is typically used to assess a well productivity index in the industry. In such instances, the well is shut-in and given time to build up to its static reservoir pressure. During the test period, the well can produce at a constant rate (q) and a stable bottom hole pressure (P_{wf}) once the static reservoir pressure has been reached. But the moment the well is allowed to flow, the stabilized bottom hole pressure value should be continuously monitored and recorded for purpose of reservoir properties analysis.

The productivity index (J) indicates the well's production capacity only if the Well is producing during a pseudo-steady state regime. Hence, allowing the Well to flow constantly for a sufficiently long period is vital to reach its pseudo-steady state.

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Factors Affecting Inflow Performance Relationship

Mostly, the inflow performance relationship is affected by several reservoir parameters. The most significant parameters include, but not limited to, well and reservoir parameters such as; reservoir pressure, well geometry, and reservoir rock properties. For example, a decrease in relative permeability to oil (K_{ro}) as gas saturation increases and formation damage around the wellbore. Fluid properties such as increase in oil viscosity as pressure decreases and gas is evolved, and shrinkage of the oil as gas is evolved when pressure on the oil decreases in flowing well are also some critical examples.

Reservoir Pressure

In its simplest term, the reservoir pressure is regarded as the force exerted by a column of water or hydrocarbon fluid from the formation's depth to sea level or by fluids inside a reservoir's pores or within the rock that makes up the reservoir. Due to consistent decline in reservoir pressure, many oil fields' production capacity has drastically reduced (Daoud *et al*, 2017). This has resulted to production rates decrease which is directly linked to a considerable decrease in reservoir pressure, as shown in (Fig.1) below:

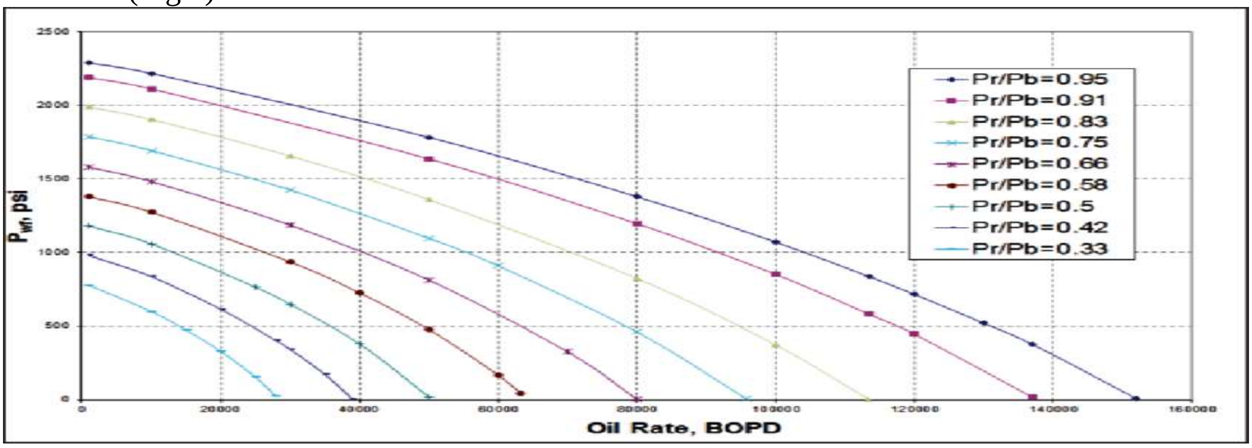

Fig. 1: The Effect of Reservoir pressure on IPR (Daoud et al, 2017)

Skin Factor

In other to analytically model the deviation from the pressure drop anticipated by Darcy's Law due to skin, the term "skin factor" is mostly utilized, and it is mathematically expressed as:

$$S = \left(\frac{K}{K_a} - 1\right) In \left(\frac{r_a}{r_w}\right) \text{-----------------(2)}$$

Where: S is the Skin Factor, K is the formation permeability, K_a is the permeability of the damaged/altered zone, r_a and r_w is the radius of the damaged zone and the radius of the wellbore respectively.

Therefore, skin factor changes might be caused by stimulation or formation damage. The value of the flow capacity (kh) of the reservoir which results from the formation permeability (k) and the producing formation thickness (h) in a producing well, significantly impacts the skin factor, (Mahdiani *et al*, 2015).

The Vogel's Method of Predicting Inflow Performance Relationship (VIPR)

Vogel in (1968), created IPRs for various hypothetically saturated oil reservoirs that are produced under various conditions by using a computer model. The Model predicts a well inflow performance under a two-phase condition based on many well simulations, and an equation was proposed. He also presented the link between the estimated IPRs and normalized them in a dimensionless setup. The IPRs were normalized by Vogel using the following dimensionless parameters specified below:

$Dimensionless\ pressure = {}^{P_{wf}}/_{P_R}$-----(3)

$Dimensionless\ flowrate = Q_o/(Q_o)max$---(4)

Where: (Q_o)max is the flowrate at zero wellbore pressure, i.e., Absolute flow Potential (AOF).
Vogel also, found the following relationship between the dimensionless parameters:

$\frac{Q_o}{(Q_o)max} = 1 - 0.2\frac{P_{wf}}{P_r} - 0.8\left[\frac{P_{wf}}{P_r}\right]^2$--------(5)

Where: Q_o is the oil flowrate at P_{wf}, BOPD; P_{wf} is the wellbore pressure measured in $Psig$, and P_R is the average reservoir pressure, $Psig$.
The behaviour of the Inflow Performance Ratio (IPR) curves of Vogel's hypothetical saturated reservoir, undersaturated reservoir and when the pressure is at the region above the bubble point is as shown in the (Fig. 2) below:

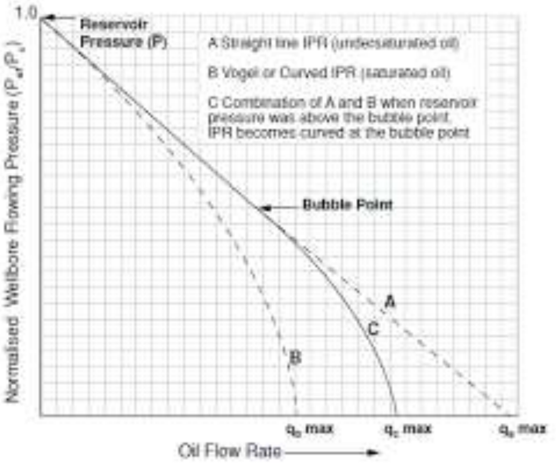

Fig. 2: Vogel Combined IPR Curve for Saturated and Undersaturated Reservoirs (Crete, 2017)

Vertical Lift Performance (VLP)

Another important parameter considered is the vertical lift performance curve which signifies the relationship between flow rate and pressure in the system. The VLP curve illustrates the pressure required to lift a specific fluid volume to the surface at a specific wellhead pressure. The vertical lift performance, also termed "outflow performance", describes the bottom hole pressure as a function of flow rate during the production of reservoir fluids in the system. In other words, it describes the flow from the bottom hole of the well to the wellhead. The outflow performance depends on several factors which includes; Production Rate (PR), well depth, tubing diameter, Water cut, and other parameters such as gas oil ratio and gas liquid ratio as part of the restriction parameters.

The Relationship between Inflow Performance and Vertical Lift Performance

This relationship relates to the wellbore flowing pressure and surface production rate that exist in a given system. In other words, the vertical lift performance shows what the well can produce to the surface at a given time, whereas the inflow performance relationship represents what the reservoir can supply to the bottom hole as shown in (Fig. 3) below:

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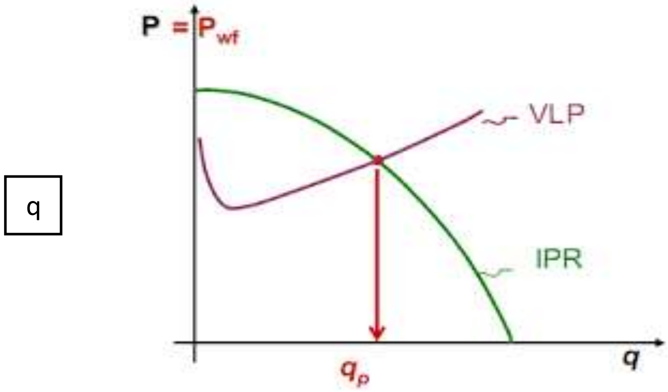

Fig. 3: The graphical representation of the Relationship between (IPR) and (VLP)

The vertical lift performance curve and the inflow performance relationship intersect at the operating point marked (q) as shown in (*Fig. 3.)* above.

Hence, the resultant effect is the well deliverability, which expresses what the well will produce under a specific operating condition prevalent in the field. However, there exist a non-flowing circumstance where there is no interaction between the (IPR) and the (VLP) curve (Handley *et al,* 2000).

Over the years, researchers have extensively deliberated on the consistency among different well rate estimation methods as a dependant factor on the validity of the parameters considered and the evolution of reservoir parameters (Wigwe, 2019). In other words, an increase in the Gas-Oil Ratio (GOR) might influence the decrease in the fluid density, thereby, causing the Borehole Pressure (BHP) to decrease while increasing the IPR rate. Moreso, decrease in the pressure across the tubing might cause the decrease in the VLP, and the pressure drop across the choke to increase in the wellbore will causing choke rate to increase.

The Artificial Lift Systems

Artificial Lift is used to overcome bottom-hole pressure so that a well can produce at a desired rate (Edwards, 1990). Artificial Lifts is mostly linked with mature and highly depleted oil and gas fields that, the reservoir pressure has dropped to the point where the reservoir can no longer produce using its inherent energy (Ismail, 2014). However, artificial lift methods are these days being applied to boost production rates and project economics in fairly newer fields that the reservoir pressure is not high as predicted during the exploration stage of the field (Ahmed, 2016).

Selection of the suitable Artificial Lift Method

The selection of a suitable artificial lift method at every given point in time in the production of hydrocarbon is essential with regards to its financial implication in the oil well long-term profitability plan (Zain and Abdin, 2000). Consequently, a wrong decision will result in low production and high operational costs. Artificial lift methods are broadly divided into two categories namely; Pumping Lifts and Gas Lifts. The bias for this research on the method of artificial lift is the gas lifting method.

The Gas Lift System

Gas injection is one of the most extensively used artificial lift techniques to boost tail-end production from matured fields (Ismail, 2014). Gas is injected into the tube as deeply as possible to mix with the

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reservoir fluid. Since the gas is less dense than the reservoir fluid, the downhole pressure decreases along with the density of the fluid in the tubing. Alternatively, the production from the reservoir increases as the downhole pressure is reduced.

In this method, compressed gas is injected at high pressure in the annulus, which lightens the fluid column by reducing its density and pressure losses. The presence of gas inside the production tubing at the deepest point reduces the flow pressure of the bottom hole to allow fluid to flow from the reservoir to the surface production gathering system.

Coltharp and Khokhar (1984), devolved a computer-based gas lift surveillance and gas injection control system installed in a well in Dubai, and the result showed a profitable return in the level of crude recovered. While Everitt (1994), showed that the gas-lift optimization efforts in a large mature field could reduce the gas-lift requirements by 50%.

The aim of gas-lift is to send the fluid to the wellhead topside equipment while maintaining a bottom-hole pressure that is low enough to create a significant pressure difference between the reservoir and bottom hole (Jahanbani and Shadizadeh, 2013).

The rate of liquid output will typically increase as bottom hole pressure is reduced because of gas injection. However, an excessive gas injection will raise the bottom hole pressure, which will cause the production flow rate to fall. There are certain drawbacks to operating a gas lift with low or high gas-lift injection rates. First, a very inefficient operation results from not precisely utilizing the full lift potential of the gas. Second, there is a chance that significant operational issues will arise when pressure surges in production facilities are this large.

Furthermore, it becomes challenging to control production. Thus, well performance analysis combines various oil or gas well components to forecast flow rates and optimize the numerous system components. The effectiveness of gas-lift wells can be affected by several problems. The factors that prevent or restrict gas injection into the well are inlet issues. Inlet/outlet issues and downhole concerns are two common categories for these problems (Zain *et al.*, 2000). Outlet issues are the conditions downstream of the wellhead that impair a well's flow ability. These include high separator pressure, inadequate flow lines or manifolds, and excessive back pressure from a production choke.
As a production well ages, the amount of oil it produces declines gradually. Around 70% of oil and gas output comes from matured oil wells spread across the globe (Ismail *et al*, 2014). The presence of gas inside the production tubing at its deepest point reduces the flowing bottom hole pressure thereby, allowing fluid to flow from the reservoir to the surface (Sylvester, 2015). This phenomenon is described by the gas lifts well schematic diagram shown in (Fig. 4) below:

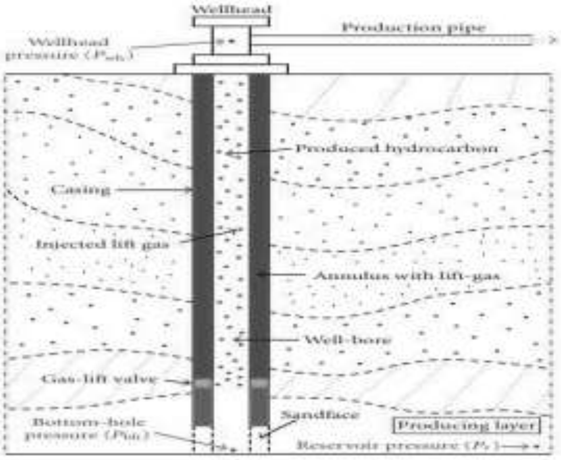

Fig. 4: Gas Lift well Schematic diagram (Rashid et al., 2012)

The instability phenomenon is one of the main problems with gas allocation optimization. The dynamic interaction between the multiphase fluid in the tubing and the injection gas in the casing causes the instability phenomenon. These difficulties should be considered before implementing any artificial lift techniques, because They gravely impair output and damage surface and downhole equipment (Mahdiani *et al.* 2015).

Typically, oil production output increases as gas injection increases. On the other hand, excessive gas injection (where the gas phase moves more rapidly than the liquid phase) will result in undersupply. Oil production will eventually decline because of this situation (Mahdiani *et al.* 2015). The gas lift optimization challenge focuses on selecting the appropriate gas injection to maximize oil output.

The decreasing condition of the surface equipment and the subsurface well completion in an established field, such as degrading well integrity with leaks and holes, inaccurate production metering, and unstable gas compressor availability and efficiency, are some predicted challenges associated with gas lift (Trjangganung, 2014).

The standard approach among many industry operators is to distribute the gas lift to a well (per a gas-lift performance curve) to calculate the ideal gas lift rate (Sylvester, 2015). Bates *et al*, 2012), highlighted the goals of gas lift optimization to achieving the optimum result to include; producing oil at a consistent rate, the parameters such as casing and tubing pressures, water cut, and wellhead temperature to be stable. Also, in other to produce the same amount of oil, there should be less gas injection.

The Integrated Production Modelling (PROSPER)

According to the Integrated Petroleum Handbook (IPH) published by Petroleum Experts Limited, PROSPER is a well performance, design and optimization programming software that is part of the Integrated Production Modelling Toolkit (IPM) system. Some of its functional applications in the oil and gas industry include:

- ❖ Design and optimization of well completions, including multi-lateral, multilayer, and horizontal wells
- ❖ Design, diagnose and optimize gas lifted hydraulic pumps and ESP wells

- Analytically generate lift curves for use in simulators
- Design and optimize tubing and pipeline sizes
- Predict flowing temperatures in wells and pipelines
- Calculate pressure losses in wells, flow lines and across chokes
- Calculate total skin and determine breakdown (damage, deviation or partial penetration)
- Monitor well performance to rapidly identify wells requiring remedial action
- Allocate production between wells
- Unique black oil model for retrograde condensate fluids, accounting for liquid dropout in the wellbore
- Etc.

A pictorial view of the main menu interface of the PROSPER IPM Simulator that is deployed for this research is shown in (Fig. 5) below:

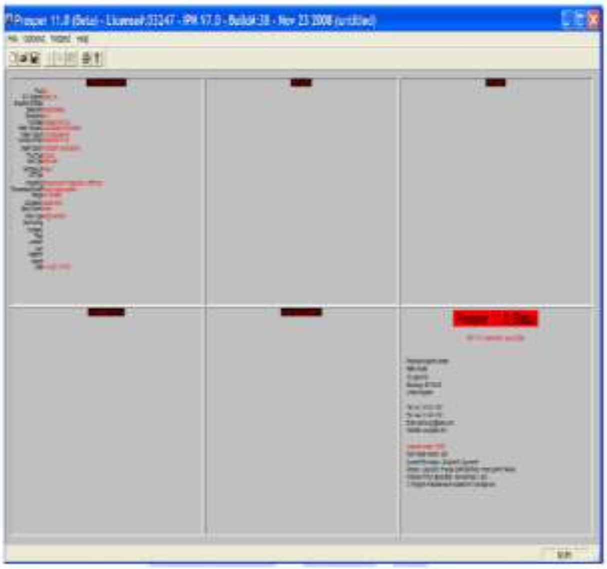

Fig. 5: PROSPER IPM Simulator main menu interface

Research Approach

The main approach for this research is to identify, evaluate and optimize the wells (under investigation) production by using PROSPER IPM Simulator, via inputting real-time field data in other to better understand the reservoir behaviour within specified operating conditions prevalent in the field. The researcher adopts the quantitative and qualitative approach as all views and analyses presented in this work are based on the analysis carried out in the simulator and not just by the bias of the researcher's perspective.

Research Design

Production data of two oil producers' wells (22T and 19L), have been obtained from the field under investigation. A few phases programming was conducted to monitor the performance and optimization of the well production. Phase one is inputting the field data into the simulator. The main menu option of the PROSPER simulator is divided into six sections, four of which must be filled for the simulation to be validated. The primary section in the main menu option allows the researcher to determine fluid descriptions, the type of well to be simulated and the artificial lift method to be adopted.

The other sections include; Pressure-Volume-Temperature (PVT), Inflow Performance Relationship (IPR), and equipment input data. Phase two is validating the input data and obtaining the best correlations possible for the analysis. Phase three simulates the base case using various operating conditions and the well analysis. Afterward, the recommendations are put forward to optimize the well productivity. The simulation flow chart is as shown in the diagram (Fig. 6) below:

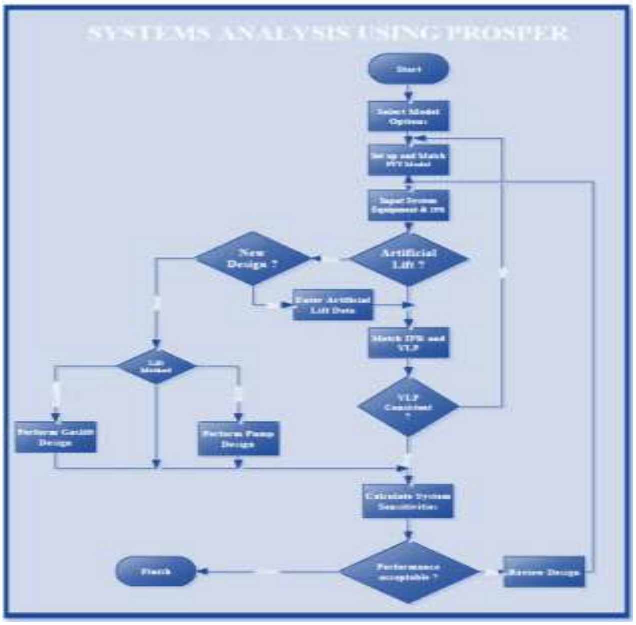

Fig. 6: The PROSPER Simulation Field Data entry flow diagram

Research Procedures

- ❖ Input data into the different sections of the simulator to determine if the data set is valid
- ❖ Determine which components in the system can be changed.
- ❖ Select one component to be optimized.
- ❖ Select the node location that best emphasizes the effect of change in the selected component.
- ❖ Obtain the required data to calculate pressure drop versus rate for all the components.
- ❖ Determine the effect of changing characteristics of the selected component by plotting inflow versus outflow and reading the intersections.
- ❖ Repeat the procedure for each component that is to be optimized.

RESULTS ANALYSIS

Two oil producer Wells was put under observation and simulation was conducted for this Optimization study. The producer wells are designated as (22T and 19L), respectively for ease of identification from the field data collected.

The OML 42 Field reached its peak production in late '90s. Since reaching its peak production, there has been a rapid decline in oil production due to an increase in water production and reduced reservoir pressure, which require gas lifting operation as part of the secondary oil recovery methods assessed for the field.

The research is targeted to simulate an economic limit of 1000STB/day production has been denoted for well (22T and 19L) as the case study wells. Any of these well producing at a rate lower than the premised rate as stated above is considered uneconomical and not viable.

Well Simulation Results Analysis
The simulation parameters obtain from the field for (Well–22T) are as shown in (*Table 1*) below:

Table 1: PVT Data for (Well–22T)

Reservoir Temperature	239 ºF
Oil Gravity	40
Gas relative density	0.766
GOR	400
Pb	2325 psia
Bo	1.388rb/STB
Oil Viscosity	0.379cp
Bg	1.388rb/STB
Gas Viscosity	0.017cp
Bw	1.047rb/STB
Gas Z Factor	3.35E-06 (1/psia)
Water Salinity	9708 ppm
Water viscosity	0.255433cp
Initial Pressure (psia)	2325
Current Pressure (psia)	1600
Water cut (%)	30

Sections of the PROSPER Simulator in (*Fig. 5*) above are been filled out with the above (*Table 1*) parameters to develop the (Well–22T) model, in order to obtain the IPR, PVT curves when the reservoir production and equipment data have been feed into the simulator.

The IPR plots obtained from the (Well–22T) model are summarized in (*Fig. 7) and (Fig. 8) below.* These IPR plots are used to forecast the (Well–22T) output performance that display the Absolute Open Flow (AOF), Productivity Index (PI), and skin values.

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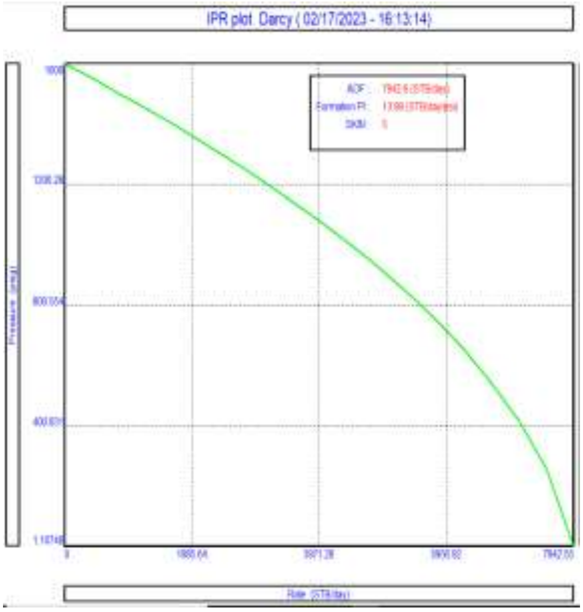

Fig. 7: IPR Plot for (Well – 22T)

The analytical diagnosis of (Well–22T) simulation shows that the well is still an economically viable production well. Although the well reservoir pressure has depleted, it still produces above the economically set (1000STB/d) limit of the simulation. Further analysis and variation of the production parameters of the well shows that the skin value and water-cut values of the well do not necessarily affect this well producibility.

The IPR vs VLP plots in (*Fig. 8)* shows that the well produces without a challenge. However, it is imperative to closely watch the water-cut (WC) as further increase in water-cut level might lead to the failure of the well to produce economically as expected.

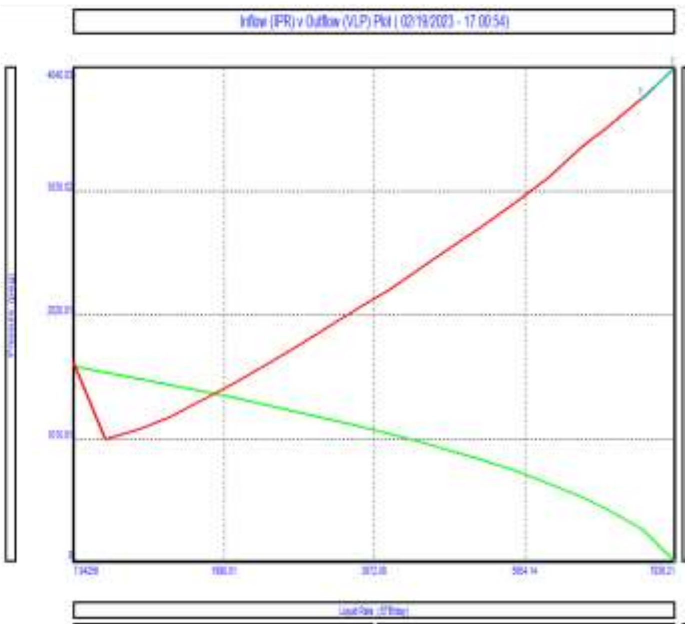

Fig. 8: IPR vs VLP Simulation for Base Case

The downhole system for Well–22T data simulations can also be obtain as shown in the (*Fig. 9*) below which describe the tubing size, depth, SSSCV size, and depth respectively.

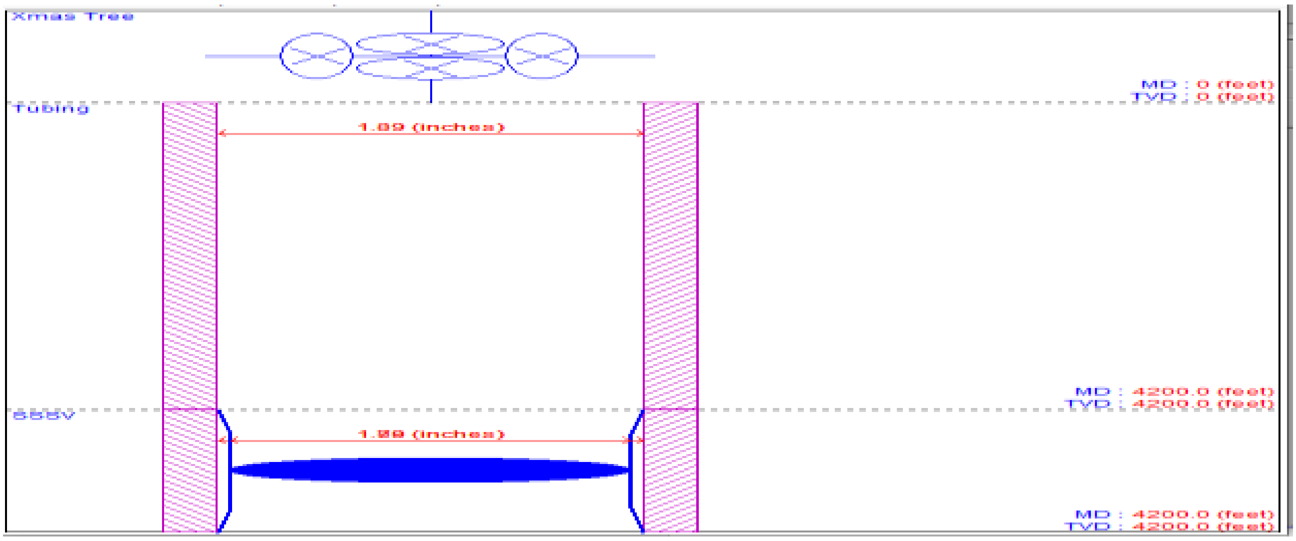

Fig. 9: The downhole system for Well–22T

However, there must be a connexion of the two curves at a point in other for the well to flow as anticipated. The (IPR) and (VLP) curve lines intersection indicates the points at which the Well–22T will flow or otherwise will not flow as expected. The joint pressure, water cut IPR vs VLP plot of Well–22T is as shown in (*Fig. 10*) below:

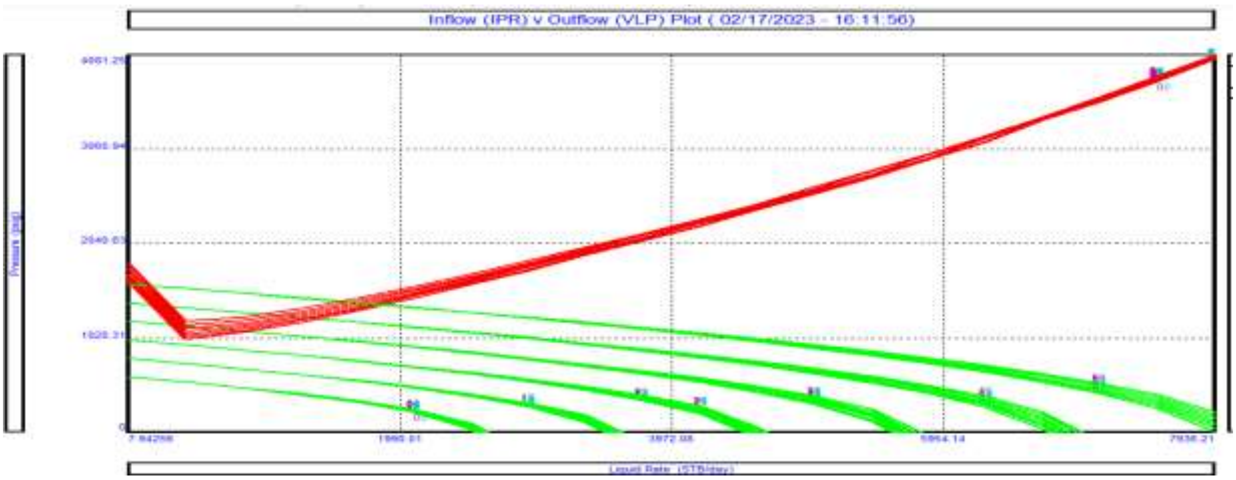

Fig. 10: IPR vs VLP Plot for Well–22T

Simulated Base Case Scenario Result

The Well–22T base case scenario was simulated using various reservoir pressure and water-cut ranges. Analysis of the result shows that, at the maximum economic water-cut of 30%, the well–22T can no longer produce at its economic rate of (1000STB/day) as reservoir pressure begins to decline. The oil rates obtained from this base case analysis are summarized in (*Table 2*) below:

Table 2: Oil Rates at different Pressure Ranges and % Water Cut for (Well–22T)

Reservoir Pressure (Psia)	**Water Cut (%)**			
	0%	10%	20%	**30%**
	Oil Rates at Different Water- cuts			
1600	1857.8	1602.9	1355.0	**1093.2**
1400	1390.8	1173.4	936.9	**697.7**
1200	880.4	656.9	409.2	**-**
1000	-	-	-	**-**

As shown in (*Table 2*), well–22T, although still producing oil at reservoir pressure of 1200(psia), and at water-cut of 20% respectively, but uneconomically at a production of (409.2STB/day). The well economical production limit is (1093.2STB/d) at a pressure of 1600Psia, and at 30% water-cut. However, the well fails to produce economically at reservoir pressures below 1600psia and water-cuts above 30%, and totally stops producing at a pressure of 1000psia at any of the water-cut range stated above. But if the well was to be produced at 0% water-cut and at 1600Psia, the economic oil production would be (1857.8STB/day).

Furthermore, analysis to evaluate various development options to optimize oil production was done. The Optimization was accomplished by adjusting the wellhead pressure, using different tubing sizes, while increasing the gas lift injection rates.

Changing the Tubing Size of the (Well–22T)

The various tubing internal diameter sizes (ID) techniques was also adopted to analysis the effect of changing tubing size on the well production output as shown in (Table 3) below:

Table 3: Oil Rate at Various Tubing Internal Diameter Sizes for (Well–22T)

Tubing Size (IN)	Oil Rates (STB/D)
2.441	1930.3
2.992	2431.0
4.09	2674.4
4.892	2598.8

As shown in (*Table 3*) above, and (*Fig. 11*) below, the oil rate differential increment attained using different tubing sizes above (2.992-in) are considerably insignificant when compared with the economic recovery limit. As a result, it will not be advisable to change the tubing size of this Well–22T.

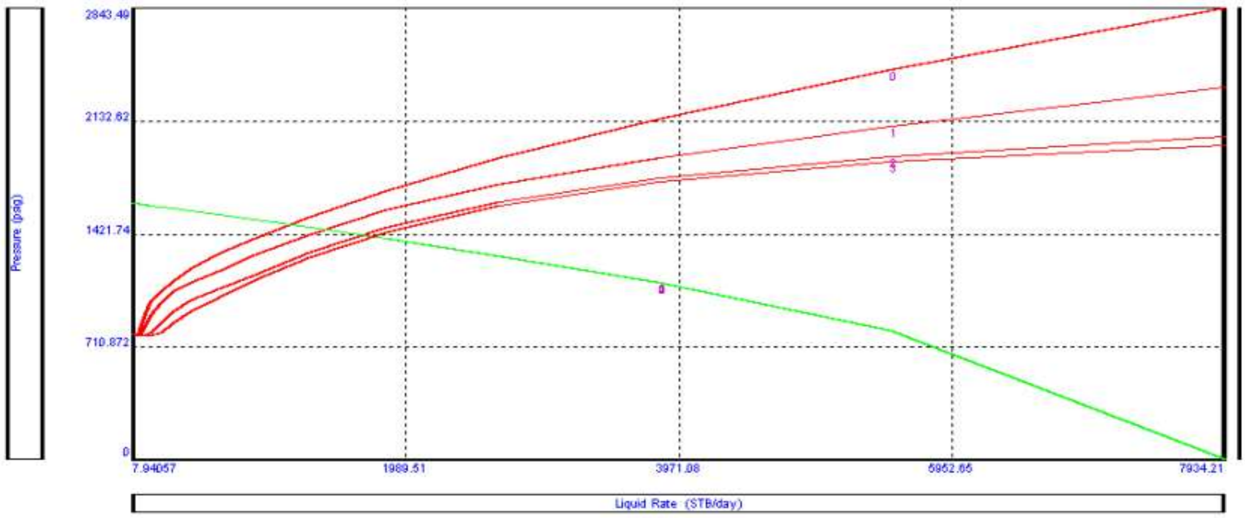

Fig. 11: IPR vs VLP Plot for Changing Tubing Size at Well–22T

Artificial Gas Lift Method Result Analysis

The artificial gas lift analysis was also conducted in other to obtain an optimum injection rate of 0.95161MMScf/D gas for the operation. At water-cuts above 45%, it is observed that the operating production rates produced have already reached the maximum economic limit.

Table 4: Oil Rate with Optimum gas Injection Rates for Well –22T

Gas Injection (MMscf/d)	Water Cuts			
	0%	**20%**	**40%**	**45%**
	Oil Rates at Different Water Cuts			
0.95161	2255.8	1714.6	1180.1	1050.1

The maximum daily economical oil production achieved at 0.95161MMScf/D gas injection is 1050.1STB/D. Thus, it is advisable to keep the water-cut below 45% and the THP low as 100psig to achieve daily economic production limits. This is as shown in (*Table 4*) above and (*Fig. 12*) below:

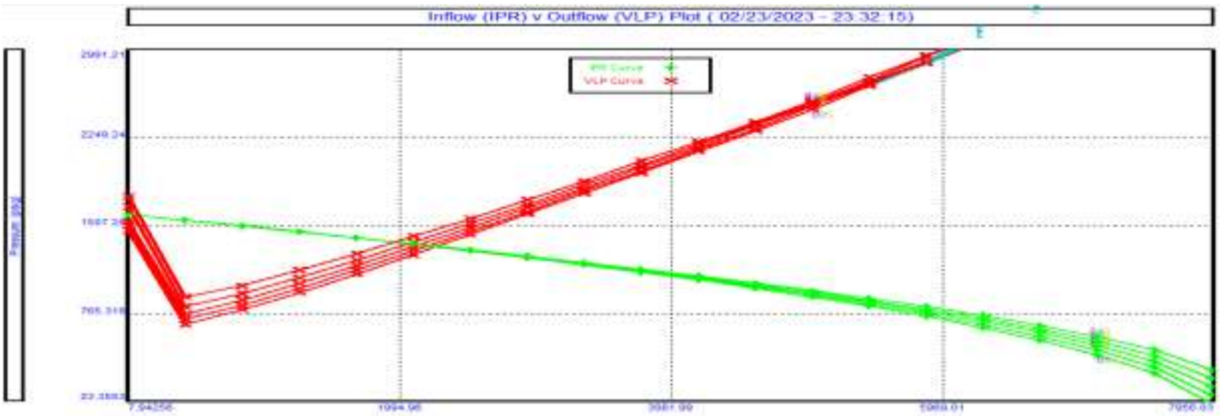

Fig. 12: IPR vs VLP for Changing Gas Lift Rate at Well–22T

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It can be therefore, concluded that; lowering Christmas tree pressure to 100psig is recommended because the well life can be extended to 50% water-cut without any disturbance. More so, changing the tubing size will not be recommendable because it does not produce an economical increment in the daily oil production rate as expected. Also, the gas lift method is economical as it produces up to a maximum economic water-cut of 45% with a gas injection rate of 0.95161MMscf/d, and oil production rates up to 1050.1STB/d respectively. However, if a (45%) water-cut is to be achieved for an economical oil production, then a topside water treatment facility will be required to deal with such high-water production rate.

PVT Parameters for (Well–19L) Simulation Result Analysis
Table 5 below shows the field parameters used for (Well–19L) simulation.

Table 4: PVT Data for Well A2

Reservoir Temperature	**239 ^{O}F**
Oil Gravity	40
Gas relative density	0.791
GOR	440 SCF/STB
Pb	2335 psia
Bo	1.388rb/STB
Oil Viscosity	0.379cp
Bg	1.387rb/STB
Gas Viscosity	0.019cp
Bw	1.047rb/STB
Gas Z Factor	3.35E-06 (1/psia)
Water Salinity	9708 ppm
Water viscosity	0.255433cp
P initial (psia)	2319
P Current (psia)	1100
THP	700
WC	40%

Simulation of Base Case Under Various Operating Conditions
In other to conduct the Well–19L Optimization process, the well was simulated within various operating conditions by changing different reservoir pressure and water-cut ranges. From the analysis of the base case, (Well–19L) presently is not flowing at the reservoir pressure of 1100psig and 40% water-cut respectively, as shown in the IPR vs VLP Plot in (*Fig. 13*) below:

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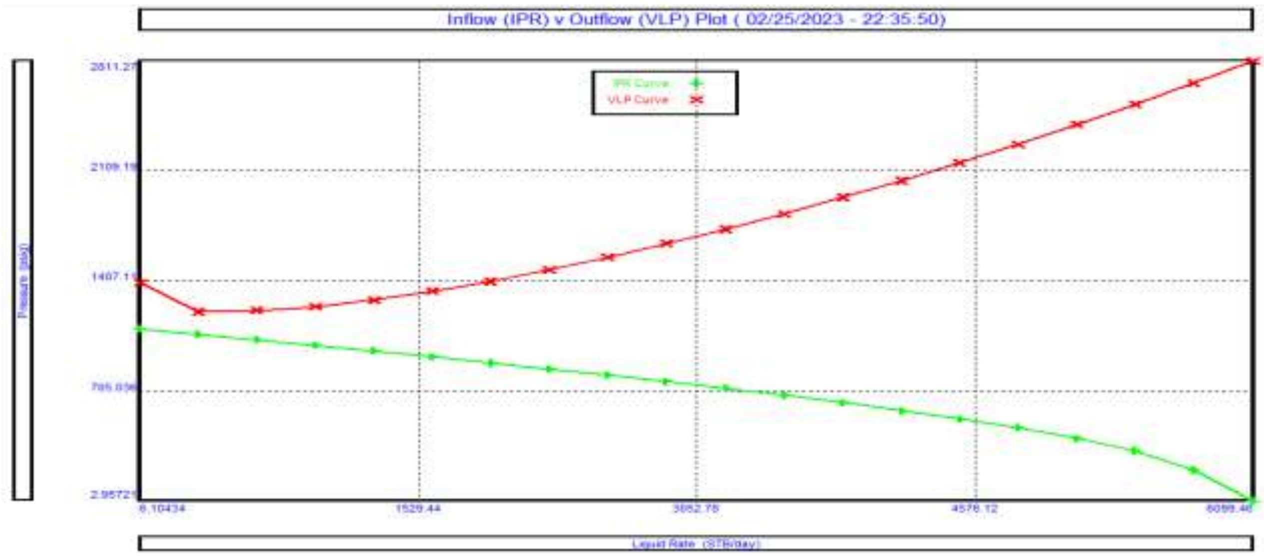

Fig. 13: IPR vs VLP Plot for Well –19L

As can be seen from the base case analysis, the reservoir pressure is needed to be increased to 1500psig for Well–19L to produce at an economic limit of 1000STB/day as expected.

Changing the Tubing Head Pressure (THP)

Based on the present analysis, (Well–19L) will eventually produce economically by lowering the THP range from 700psig to 500psig, and at 40% water-cut, even though it is still producing at an uneconomic rate of 603.1STB/d, which is lesser than the expected economical range of at least 1000STB/d, as can be seen in (*Table 6*) below:

Table 5: Oil Rates at Various THP and Water-Cut

THP (Psig)	Water Cuts (%)				
	0	**10**	**20**	**40**	**60**
	Operating rates at different water cuts				
700	-	-	-	-	-
500	1218.2	1067.2	916.5	**603.1**	271.6
350	1668.1	1485.7	1303.5	**942.0**	581.0
250	1910.7	1706.5	1509.7	**1112.8**	712.5

Simulating the well to produce at the required economical rate (1000 STB/d), the THP is lowered from the current (700psig) to a more acceptable range of (250psig) at 40% water-cut; which improved economical production rates to (1112.8 STB/d). See (*Fig. 14*) below:

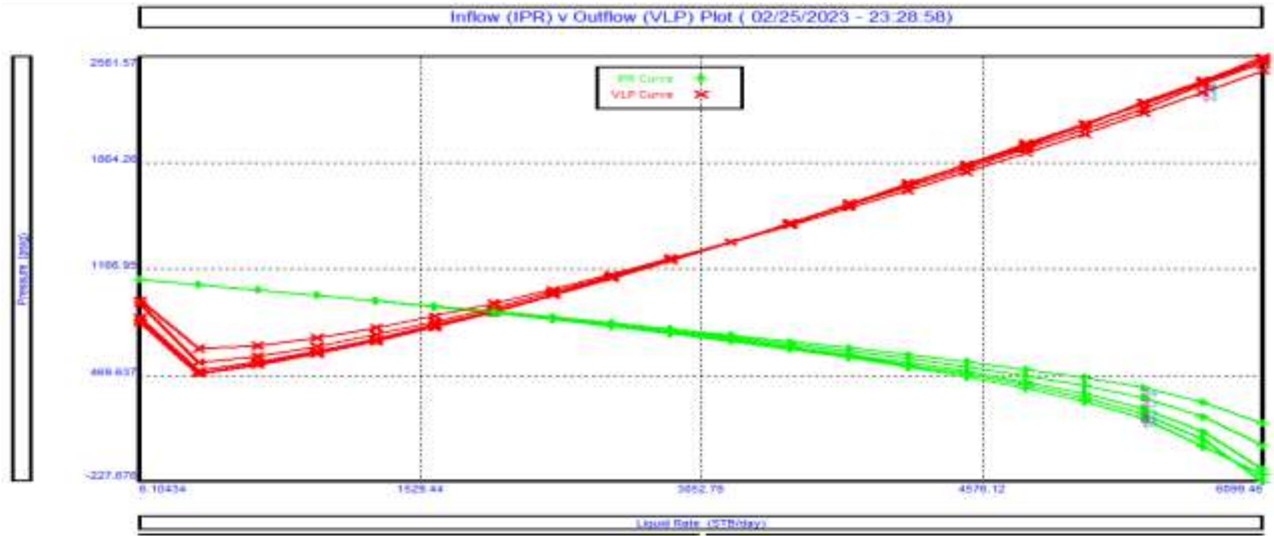

Fig. 14: IPR vs VLP for Changing Tubing Head Pressure (THP) of Well–19L

Artificial Gas Lift Method for Well–19L

In other to obtain a suitable artificial gas lifted production rate, analysis was performed on the well to finding the required gas injection rate suitable for (Well–19L) to flow economically. It was discovered to be at the injection rate of 1.01836MMSCF/d. See (Table 7) below:

Table 6: Oil Production Rate @ various Injection, and Water-Cut Rate

Gas Lift Injection rate	**Water Cut**				
	0	**10**	**20**	**40**	**60**
	Production rates @ Different Water-Cuts				
0.5	718.0	638.6	560.2	**407.6**	261.5
0.9375	702.9	625.5	549.3	**401.0**	258.7
1.01836	696.7	620.1	544.7	**397.9**	257.0

However, at this injection rate for the base analysis, the Well fails to produce at the required economic limit of (1000STB/d). This analysis is illustrated in the IPR vs VLP diagram shown for the gas-lifted (Well–19l) in (Fig. 15) below:

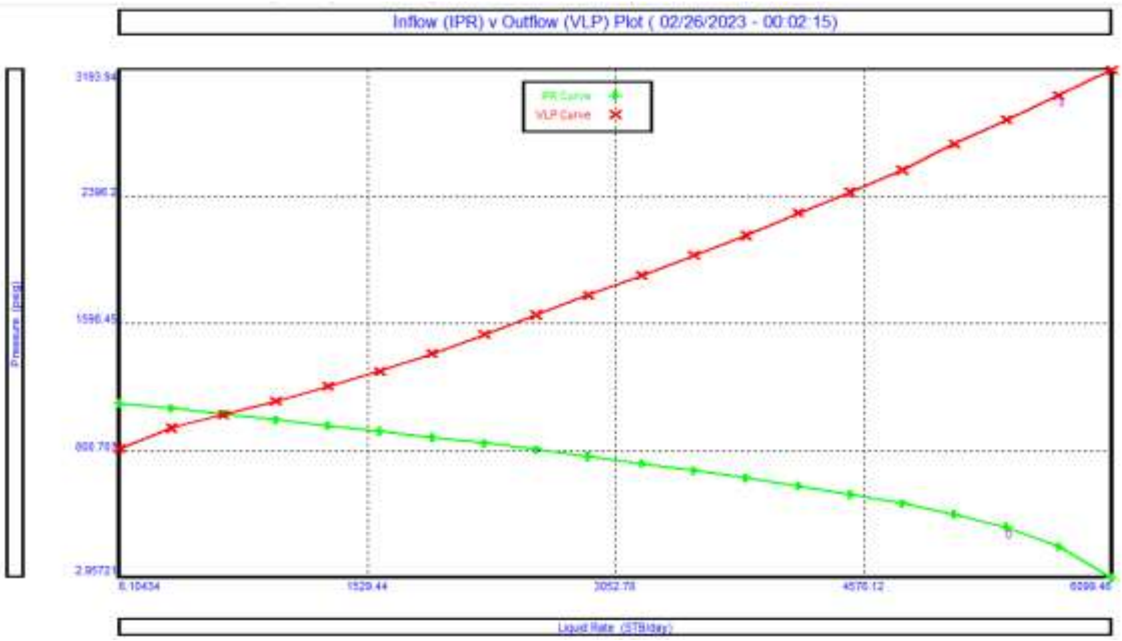

Fig. 15: IPR/VLP Plot for a Gas Lifted Well–19L

The gas lift design performance curve is also plotted as shown in (Fig. 16), which indicates the gas-lift design made for (Well–19L). The diagram (Fig. 16) also indicates the Optimum Injection pressure of the well as simulated.

Fig. 16: Gas Lift Design Optimum Gas Injection Rate Performance Curve

As demonstrated from the above gas lift analysis, introducing a gas lift injection pressure of 1.01836MMSCF/d, and reducing the THP from 700psig to as suitable as (250psig) at a water-cut of 40%, (Well–19L) is expected to produce economically more than 1000STB/d. However, it is observed that injecting gas at the optimum injection rate is not economical and leads to gas waste. It is therefore, necessary to inject at a rate lower than the optimum gas injection rate for economical oil recovery.

Changing the Tubing size of Well–19L

Analysis on the use of various tubing internal diameter (ID) sizes was also conducted. The oil rates increment obtained using different tubing sizes are considerably smaller than expected. Thus, changing the tubing size in Well–19L is not economical nor recommendable because the differential tubing size above (2.442-in) has no effect economically based on the daily economical production target. This is illustrated in (*Table 8*) and (*Fig. 17*) below:

Table 7: Oil Rate at various Tubing Internal Diameter Sizes for (Well–19L)

Tubing Size (IN)	Oil Rate
2.442	641.6
2.992	824.9
4.09	966.0
4.892	978.9

It's worthy to note that; changing tubing size is not recommended as it does not produce a productive increment in the oil production rate. However, the gas lift method is economical as it makes the less producing Well–19L to produce economically after gas injection. Gas must be injected at a rate lower than the optimum gas injection rate of (1.01836MMSCF/d) to reduce gas wastage and extend the (Well–19L) production life-cycle.

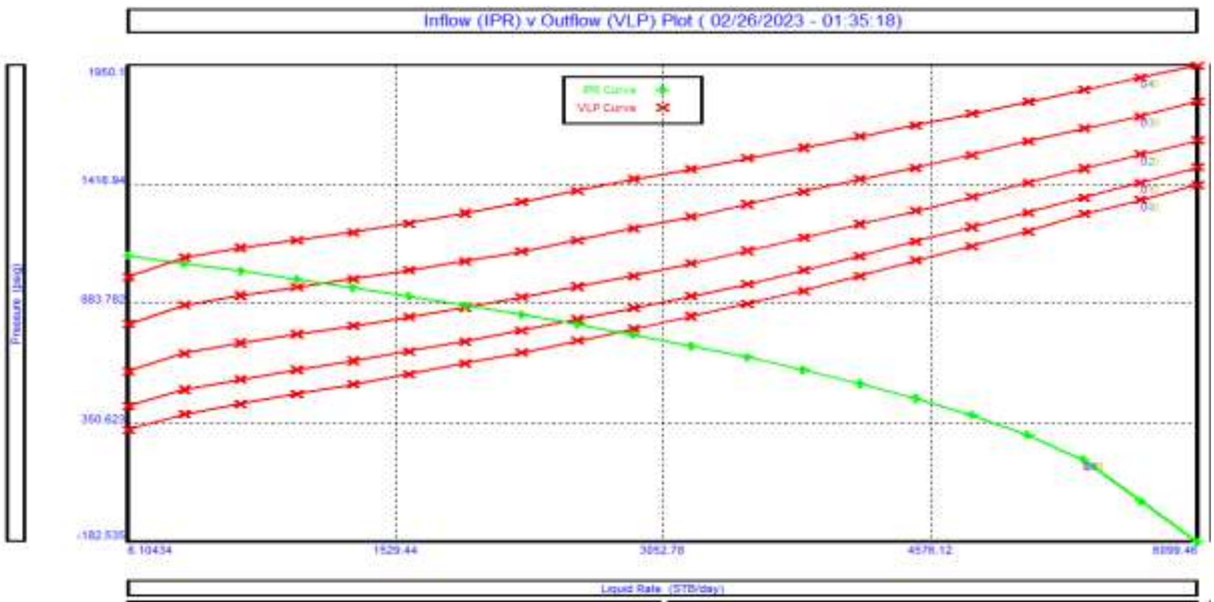

Figure 17: IPR vs VLP for Changing Tubing Size at (Well–19L)

Effect of Injection Pressure and Injection Rate on Well Productivity

It is a well-established fact that oil and gas reservoir pressure will gradually decrease throughout the reservoir production life-cycle. Similarly, after the water breakthrough, the fluid column weight will increase as hydrostatic pressure rises due to the increased density of the water and oil mixture. In which case, reservoir pressure might not be able to lift the fluid from the bottomhole to the surface production facilities. This necessitates the need for the artificial gas lift technique in other to boost the energy level of the reservoir and help to achieve more hydrocarbon production economically.

CONCLUSION

As earlier mentioned, this research was conducted to provide tangible evidence for optimizing productivity in (OML 42) located in the Niger Delta Region of Nigeria, using the artificial gas lift technique. The technique was conducted with the aid of a well simulation process from the Integrated Production Modelling software known as (IPM-PROSPER). Two different production data of oil producer (well–22T and well–19L) from the selected field was been simulated. The wells behaviour under the simulated production conditions were critically analysed to show that the artificial gas lifting technique can help significant hydrocarbon production. The research result also proves that, application of artificial gas lift can improve well productivity in the chosen field up to 1000STB/d for wells that are not producing economically. Furthermore, the researcher also deduced from the analysis that optimal gas injection rate required to lift the subsurface hydrocarbon from previous low-producing wells economically is at the rate of 0.95161MMScf/d and 1.01836MMSCf/d respectively. It is therefore, concluded that even though injecting at these optimal gas injection rate improves the well productivity, it well be beneficial to the overall life-cycle of the producing wells to inject below the above injection rates that will increase well life-cycle, and still obtain higher production rates without any challenge.

It is also, recommended that:

- Accurate field well test data should be deployed always to simulate and create suitable well model if the study is to be conducted in other fields. The production optimization for this research is only carried out using a solid model with PROSPER software. Thus, further research should be conducted using other software such as MBAL or GAP and other well model.
- The researcher also, noticed during the analysis that, water-cut levels increase with increase in production rates. While the well production rates were still considered economical, high water-cut levels may prove to be a problem when the topside production facility does not have the required waste-water treatment and disposal equipment. Therefore, further research needs to be conducted in order to reduce water-cut levels while increased production rates is achieved.

Abbreviation and Nomenclature

PVT – Pressure-Volume-Temperature
IPM – Integrated Production Modeling
IPR – Inflow Performance Relationship
EOR – Enhanced Oil recovery
AL – Artificial Lift
PI – Productivity Index
THP – Tubing Head Pressures
WC – Water cut
STB – Stock Tank Barrel
TPR – Tubing Performance Relationship
VLP – Vertical Lift Performance
GOR – Gas-Oil Ratio
GLR – Gas-Liquid Ratio
BHP – Borehole Pressure
BOPD – Barrel of Oil Produced per Day
ID – Internal Diameter

q *– Liquid flow rate, STB/day*
J *– Productivity Index, STB/day/psi*
P_R *– Average reservoir pressure, psi*
$P_{wf:}$ *– Wellbore flowing pressure, psi*
r_w *– Wellbore radius, ft*
r_e *– external drainage radius, ft*
S *– Skin factor, dimensionless*
H *– Reservoir thickness, ft*
μ *– Viscosity, cp*
Bo – Formation volume factor, resbbl/STB
Kro – Relative permeability to Oil
k *– Permeability*
k_a *– permeability of the altered zone*
r_a *– radius of the altered zone*
r_w *– radius of the wellbore*
SSSCV – Subsurface surface control valve

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