

COMPARATIVE EVALUATION OF ARTIFICIAL LIFT METHODS ON A NIGER DELTA FIELD

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ABSTRACT

During the reservoir production life reservoir pressure will decline. Also after water breakthrough the fluid column weight will increase as hydrostatic pressure will increase because of increased water and oil mixture density. In this case, reservoir pressure may not be enough to lift up the fluid from bottom to the surface. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. Artificial lift system technologies are used to augment fluid production from the reservoir. These fall into several categories depending on the operating principle, design and energy source. Artificial lift techniques are applied to add energy to the produced fluids. Artificial lift as a system of adding energy to the fluid column in a wellbore to initiate and enhance production from the well is necessary when reservoir drives do not sustain acceptable rates or cause fluids to flow at all in some cases; which use a range of operating principles, including pumping and gas lifting. The reliability of the production forecast is dependent on the reservoir pressure, and mostly the water cut. A small change in water cut gives a large change in oil production. This study uses a simulation based model of the PIPESIM artificial lift method based on operating limits of each artificial lift technique to present suitable artificial lift type regarding application conditions for a hypothetical well on a Niger Delta field. The results from the developed simulation based model shows that the ESP solution gives a superior production rate compared to gas lift and the “base case”.

Keywords: Artificial Lift, Production, Downhole, Water cut, Fluid flow, ESP, Gas lift

INTRODUCTION

The production of crude oil in oil reservoirs can include up to three distinct phases; primary, secondary, and tertiary recovery. Fluids will flow from reservoir to the surface when the well is completed and reservoir pressure is sufficient to receive fluid from matrix, transport it to the wellbore and lift to the surface. During primary recovery, the reservoir's natural pressure, combined with pumping equipment, brings oil to the surface. During the reservoir production life reservoir pressure will decline and this could cause increase in water cut and decrease in gas fraction (Clegg, 1988). These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline. Before artificial lift application the wells were being produced only naturally. Therefore, most of the brown fields were abandoned as reservoir pressure depleted. Because wells were produced under the natural flow regime and there wasn't any additional energy to the well as bottom-hole pressure decreased. Additional energy source must be added to the well in order to lift up the fluid to the surface. In these cases, artificial lift techniques are applied to add energy to the produced fluids. Artificial lift is used in petroleum production when the energy

of the reservoir is not enough to sustain the flow of oil in the well up to the surface with satisfactory economic return. Artificial lift allows wells that are non-flowing or insufficiently flowing to be produced (Saepudin et al., 2007). It is mainly designed for oil producers but the technology can also be applied to wells that produce water for a number of different uses such as for utilities or water injection to maintain pressure. It may prove necessary from the beginning of production for oil wells when the reservoir does not have enough energy to lift the fluid to the surface process facilities or when the productivity index is deemed inadequate.

ARTIFICIAL LIFT LITERATURE SURVEY

Artificial lift methods fall into two groups as presented in table 1 below. Those that use pumps and those that uses gas.

Table 1. Artificial Lifts Methods Group

Pump Types	Gas Method
Beam Pump / Sucker Rod Pumps (Rod Lift)	Gas Lift
Progressive Cavity Pumps (Jet /piston lift)	
Subsurface Hydraulic Pumps	
Electric Submersible Pumps (ESP)	

Maximizing the use of natural energy in a reservoir is critical to any production installation. In a naturally flowing well there is enough energy stored in the reservoir to flow the produced fluid to the surface. Reservoir pressure and formation gas provide this energy in the flowing well. When reservoir energy is too low for natural flow, or when the desired production rate is greater than the reservoir energy can deliver, it becomes necessary to put the well on some form of artificial lift. It is estimated that 95% of the world's oil wells are on some form of artificial lift (Mathew, 2013).

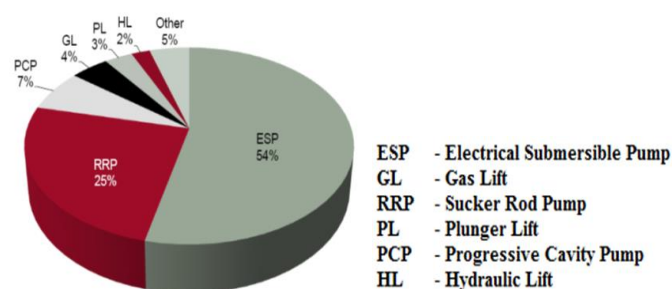


Figure 1: Artificial Lift Market Share by Type

An oil well usually flows naturally initially, that means the pressure at well bottom is sufficient to overcome the pressure losses in the well and flow line to the separator. When the criteria is no longer met due to decrease in bottom hole pressure, or pressure losses in the well become too great, the natural flow stops and the well dies. The increased pressure losses in the well can come from increased overall density due to decreased gas production, increased water cut or mechanical problems like downhole restrictions (scale etc.). Figure 2 presents the schematic pressure profile for production system and Figure 3 presents the IPR and VLP curves.

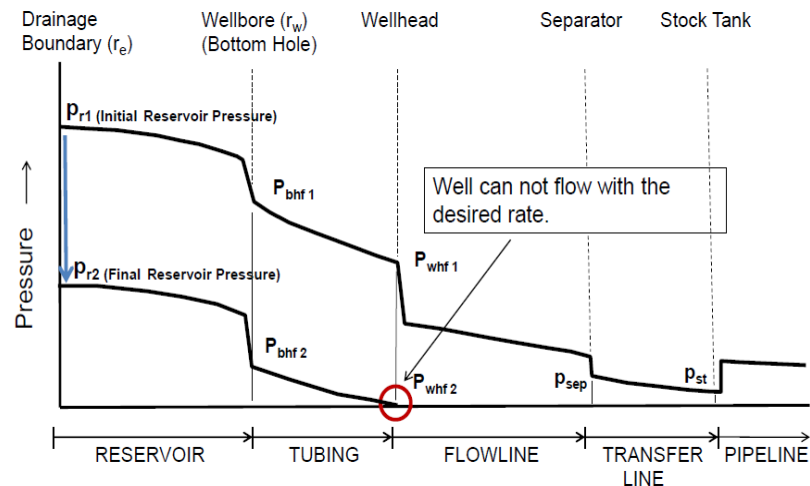


Figure 2: Schematic Pressure Profile for Production System (Source: HWU)

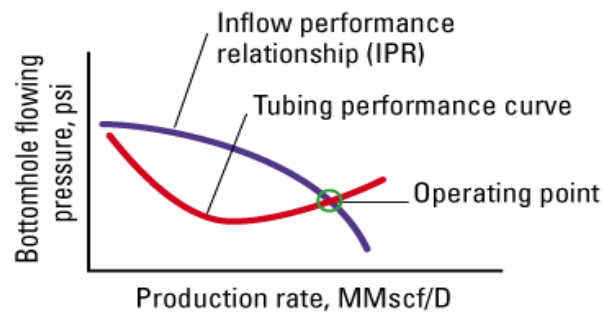


Figure 3: IPR curve Operating point (intersection between IPR and VLP curves)

Artificial lift is required when a well will no longer flow or when the production rate is too low to be economic. Figure 4 illustrates such a situation - the reservoir pressure is so low that the static fluid level is below the wellhead.

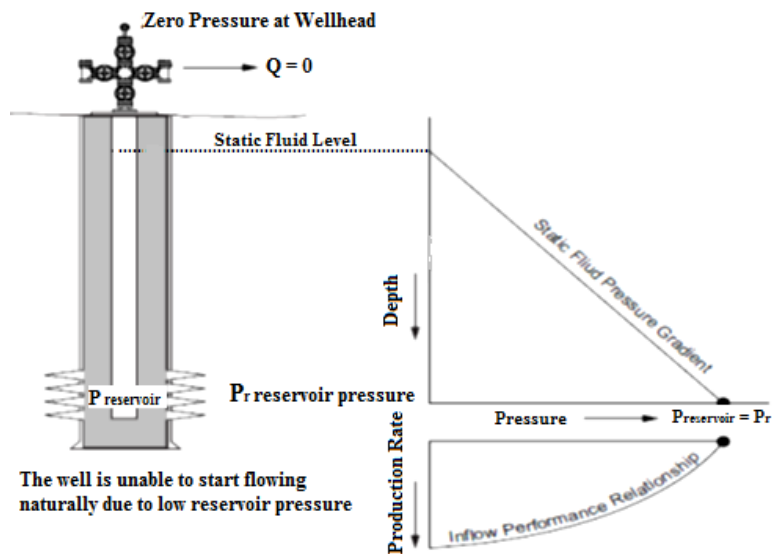


Figure 4: Well not flowing due to low reservoir pressure [8]

Review of Artificial Lift Techniques

The most popular forms of artificial lift are;

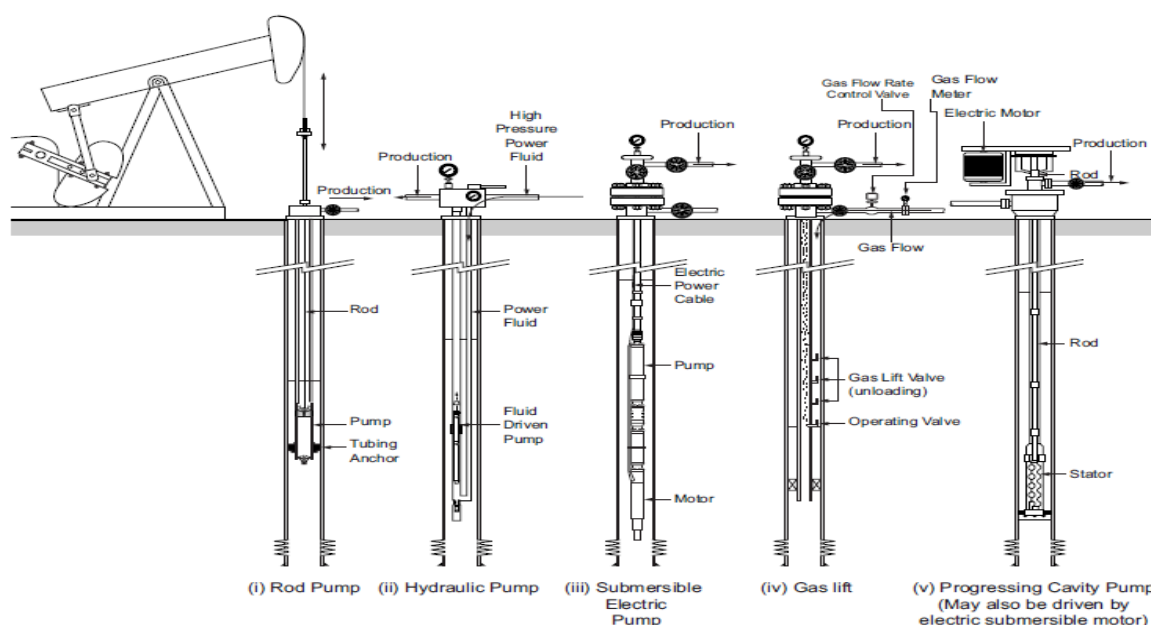


Figure 5: The most popular types of artificial lift (Source: Elshan, 2013)

i. Rod Pumps

In rod pumps, a downhole plunger is moved up and down by a rod connected to an engine at the surface. The plunger movement displaces produced fluid into the tubing via a pump consisting of suitably arranged travelling and standing valves mounted in a pump barrel.

ii. Hydraulic Pumps

This type of pumps uses a high pressure power fluid to drive a downhole turbine pump or flow through a venturi or jet, creating a low pressure area which produces an increased drawdown and inflow from the reservoir.

iii. Electric Submersible Pump (ESP)

The Electric Submersible Pump (ESP), employs a downhole centrifugal pump driven by a three phase, electric motor supplied with electric power via a cable run from the surface on the outside of the tubing.

iv. Gas Lift

Gas Lift involves the supply of high pressure gas to the casing/tubing annulus and its injection into the tubing deep in the well. The increased gas content of the produced fluid reduces the average flowing density of the fluids in the tubing, hence increasing the formation drawdown and the well inflow rate.

v. Progressing Cavity Pump (PCP)

This employs a helical, metal rotor rotating inside an elastomeric, double helical stator. The rotating action is supplied by downhole electric motor or by rotating rods.

METHODOLOGY

Development of the PIPESIM System

The PIPESIM software modeling tool is an integrated petroleum engineer and facilities package for design, operation and optimization. PIPESIM is a production engineer's tool that covers a wide range of applications relevant to the oil and gas industry. The software allow building of well models with the ability to address all variables such as well configuration, fluid characteristics (PVT), multiphase VLP correlations and various IPR models. The artificial lifting methods available are:

- a. Electric Submersible Pump – ESP
- b. Gas Lift
- c. Rod Pumps

A full range of well types can be modelled in PIPESIM which includes gas, gas condensate, liquid, liquid and gas, steam. Different configurations such as angled, multi-layer and multi-laterals can also be modelled as well as various completion configurations such as gravel pack, open, cased and perforated hole are also available. Pipesim uses a full range of IPR models.

Basic theory of PIPESIM

To predict pressure and temperature changes from the reservoir, along the wellbore and flow line tubular it is necessary to accurately predict fluid properties as a function of pressure and temperature. The Black Oil PVT model is used for the vast majority of applications. Different applications can be chosen for the Black Oil model in PIPESIM. Black oil fluid modeling utilizes correlation models to simulate the key PVT fluid properties of the oil/gas/water system. These empirical correlations treat the oil/gas system as a simple two component system, unlike the more rigorous multi-component compositional model methods. The hydrocarbon is treated simply as a liquid component (if present) and a gas component related to stock tank conditions. All that is needed for most applications is a minimum of production data, oil gravity, gas gravity, solution gas/oil ratio and, if water is also present in the system, the watercut.

Black oil fluid modeling is appropriate for use with a wide range of applications and hydrocarbon fluid systems. In general, the basic black oil correlations will provide reasonable accuracy in most PVT fluid property evaluations over the range of pressures and temperatures likely to be found in production or pipeline systems.

It should be noted that the black oil calibration feature is only applicable to oil fluid types, as it is not appropriate for a gas fluid type. The oil and water model which is used for this study, takes the surface production of oil and associated gas together with the water cut to determine the well mass flow rate.

There is no universal rule for selecting the best correlation for a given well. The correlation must be selected on the basis of flow regimes and closeness of fit to measured pressure data. In making a selection the purpose of analysis should be considered. The IPR describes pressure drawdown as a function of production rate.

Building a Model

The first step when modelling a new well in PIPESIM is to select a method and fill out a system summary like Figure 5 shows. The Black Oil model, with the oil and water option describing the fluid, is used (PIPESIM User Guide, 2008).

Figure 5: Layout of PIPESIM system summary

After entering the fluid data, the next step is to fill in the PVT data. First the basic data for the Black Oil model for the well is entered (Appendices A to B). Second, PVT test data is entered and matched to the Black Oil correlations.

Then a well model is constructed and a Nodal Analysis performed at bottom hole. (At the initial stage, no pump in the well is assumed).

Pump Selection/Design

In selecting and designing the ESP, the design condition given in appendix E is used, with the aim to determine the following:

- i. The number of stages required using Reda HN13000 pump.
- ii. The motor HP required.
- iii. Generate a Pump Performance Plot showing the potential operating flowrate range for variable frequency between 50 to 70Hz.

Also, from the Pump Performance Plot, the flow rate that the pump pressure will fall below the bubble point is determined.

Gas Lift Design

When performing a gas lift design, the best compromise between a numbers of objectives are sought:

- i. Find optimum production and lift gas injection rates.
- ii. Inject gas as deep as possible.
- iii. Determine depth and number of unloading valves.
- iv. Produce at stable conditions without "heading" and avoiding pressure surges that could result in multipoint injection and cause pressure fluctuations large enough to be disruptive to surface facilities.

When designing a gas lift system with more than one well, one should optimize the allocation of available gas, so that the total production is maximized. The developers of PIPESIM have made software for this (GAP), but this is not the scope of this study and has not been done.

Modelling the Well with Gas Lift

When modelling a gas lift well a number of parameters have been entered into the system. The design conditions given in appendix F and G were used to determine the required Mandrel spacing to unload the well and also to test rack pressure of each of the unloading valves.

RESULTS AND DISCUSSIONS

Base Case

Given the input parameters in the appendix, PIPESIM gives a production profile, with no artificial lift, for the hypothetical well. The well has no oil production, therefore the well must be considered as dead. (see Figure 6)

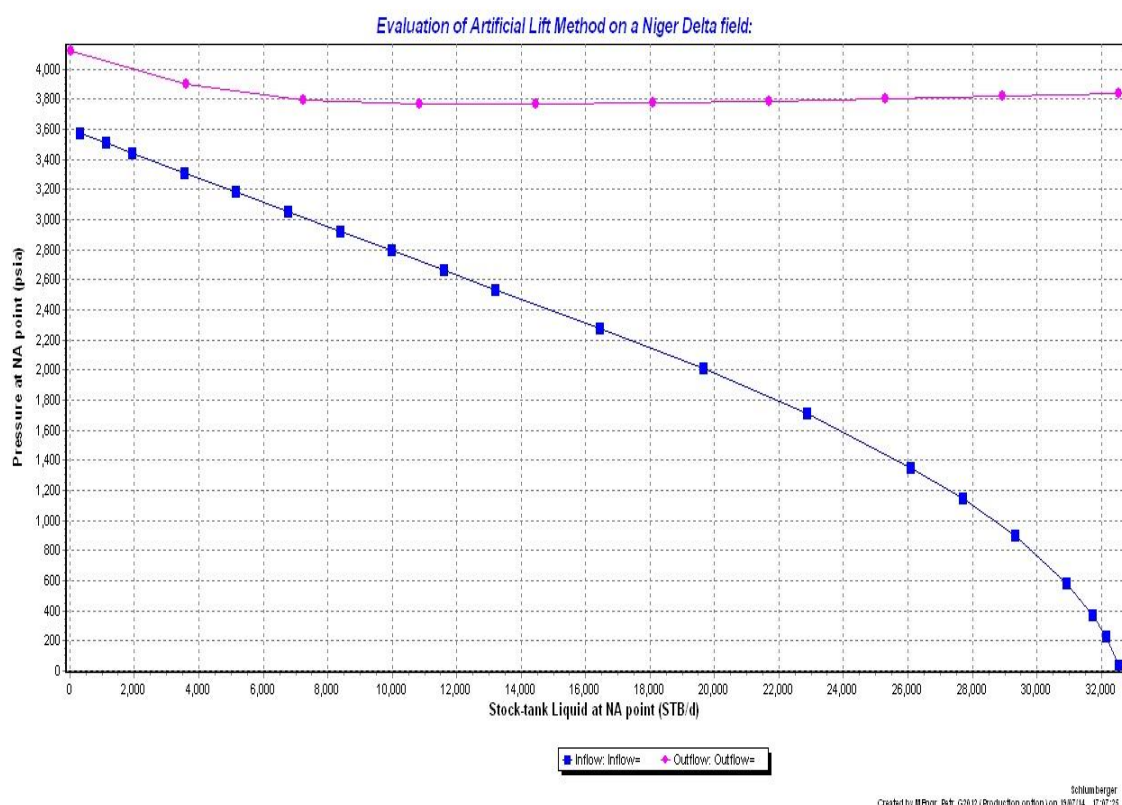


Figure 6: Well Production with No Artificial Lift
(No intersection between IPR and VLP “situation today”)

For implementation of gas lift or ESP in the well, a full workover is necessary. ESPs are a part of the tubing, and the well does not contain side pockets so that gas lift valves can be installed by wireline. However, the current well completion is used for the PIPESIM simulations. Inner and outer diameter of casings, tubings and liners are put into the model. Inner diameter of restrictions like the downhole safety valve is also accounted for. A tubing and casing inside roughness of 0.0006inch is used. Figure 7 shows the schematics of the modelled well.

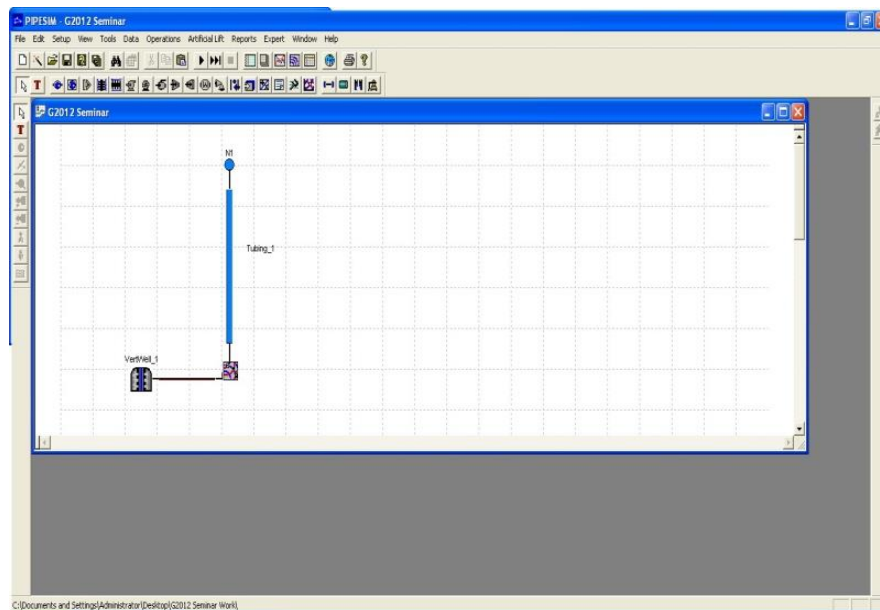


Figure 7: Schematics of the Modelled Well

ESP Considered

The wells show a significant production compared both to the ESP case and base case (no artificial lift).

The well has a total liquid rate which lies well within the operating range of the pump, between the minimum and best efficiency line. This means that there is still a good capacity for handling more fluid. Figure 8 shows the production point, which is the intersection between the VLP and IPR curve.

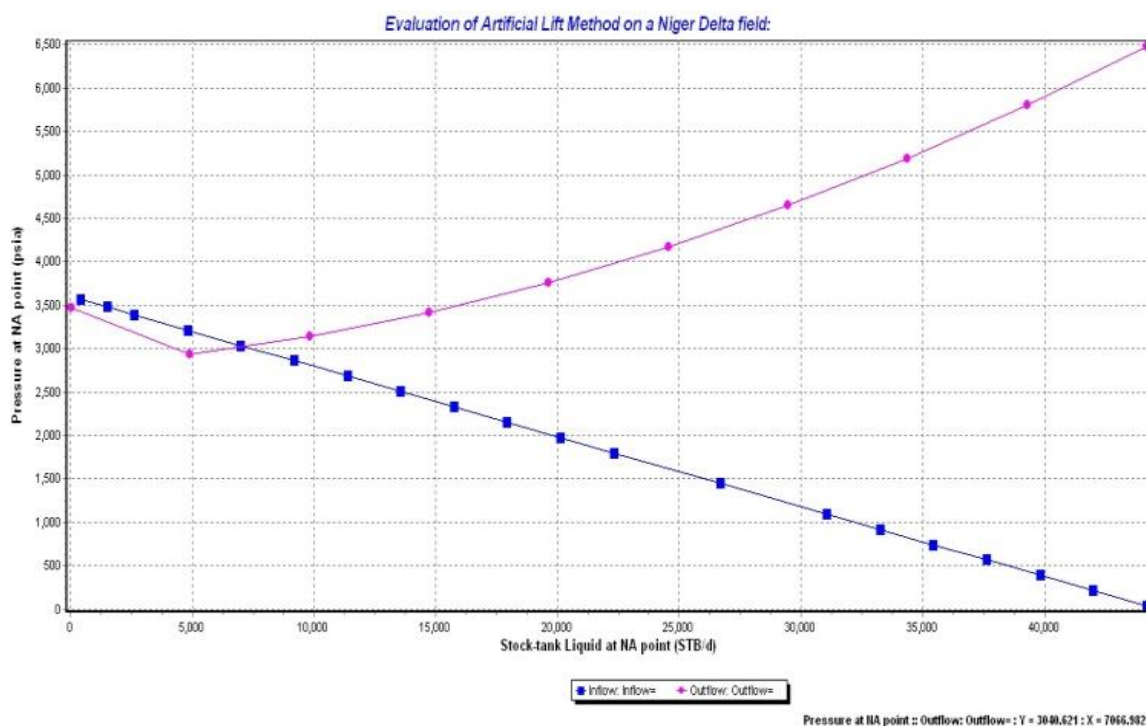


Figure 8: Production point, the intersection between the VLP and IPR curve.

Modelling the Well with ESP

Using the ESP design conditions in appendix E, the pump design data were inputted into the PIPESIM database and the Select Pump button clicked, which filters the pump database for all the pumps that meet the design criteria (Figure 9 & 10). With these coefficients the software calculates pump curves (Figure 11) so that one can simulate for any condition.

Figure 9: ESP Design input layout

	Manufacturer	Model	Diameter (inches)	Qmin (bbl/d)	Qmax (bbl/d)	Eff. at Design Condition (%)
1	Reda	JN10000	6.75	8000.00	14500.00	75.09
2	Reda	SN8500	5.38	6000.00	11000.00	71.91
3	Reda	GN10000	5.13	7000.00	12000.00	65.94
4	Reda	HN13000	5.63	9200.00	16400.00	61.23
5	Reda	HN13500	5.62	4500.00	18250.00	59.82
6	Reda	HN10000	5.63	5000.00	18000.00	59.77
7						
8						
9						
10						

Figure 10: ESP input pump selection layout

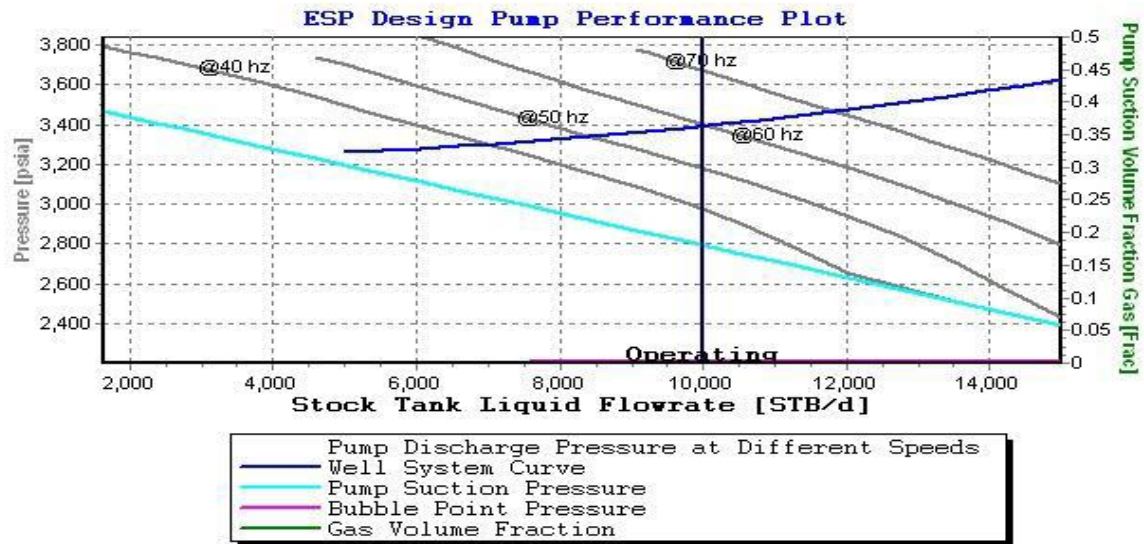


Figure 11: ESP Design Pump Performance Plot

There are two options when modelling an ESP well. One is to enter the design menu and let PIPESIM design the ESP scenario, and choose a pump from the options that the software suggests like in this case. The second option is to enter the pump data directly when type of pump and motor is already decided.

Table 2: Result gotten from the ESP design

No. of stages (HN13000)	32
Motor HP required	180.44348hp
Flow rate range for 50 – 70Hz	8357.06 – 118223.96bbl/day
Flow rate for $P_{\text{suction}} \leq P_{\text{bubblepoint}}$	16000bbl/day

The selected pump when installed on the well model generated a plot of calculated Stock Tank Liquid Rate vs. Water Cut shown in the figure 4.8 below, considering an outlet pressure of 130psia (Figure 12). From the plot (Figure 13), the production rate at 95% water cut is 9017.46 stb/day.

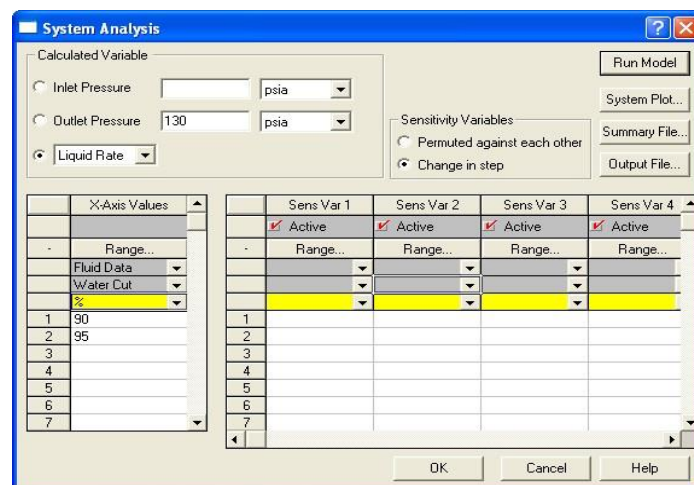


Figure 12: ESP system analysis layout

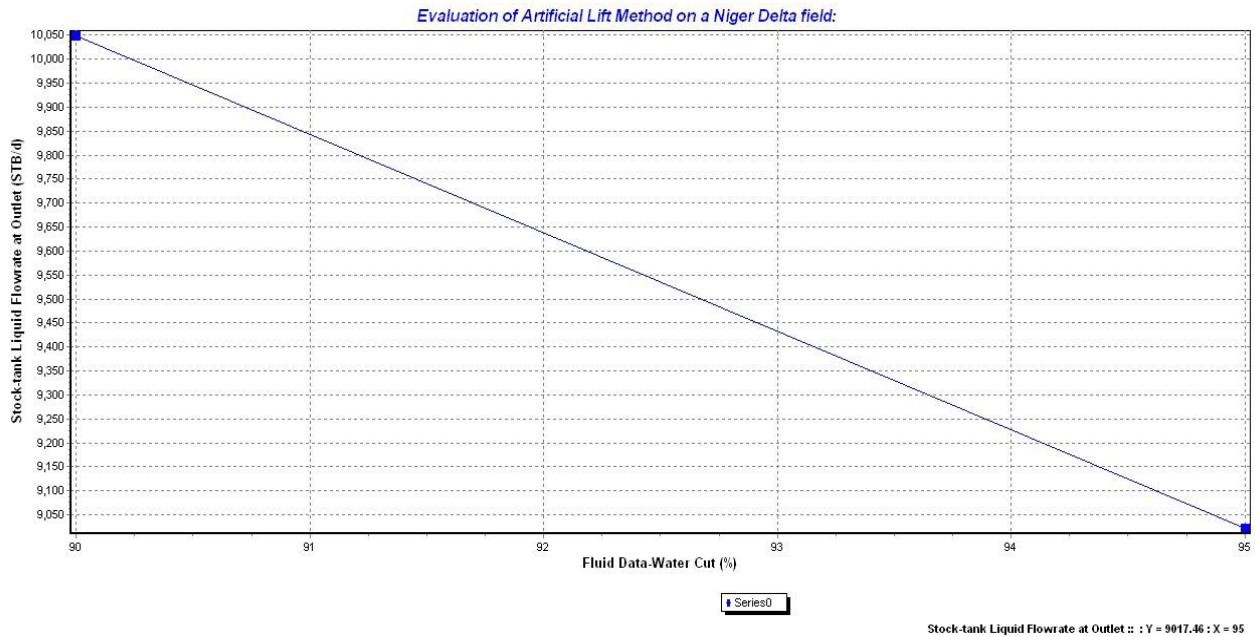


Figure 13: Plot of calculated Stock Tank Liquid Rate vs. Water Cut

Gas Lift Considered

An operating injection gas surface pressure of 1000psig and sensitivity values of 150 and 250psi for the Minimum injection gas dP across valves was assumed. Also gas lift rate sensitivity values of 0 to 5mmscf/d were entered; optimum injection depth for the well is set. For this study a “SLB Camco BK-1” valve is chosen from the PIPESIM database. The software calculates which port sizes that will generate optimal production. A valve from another manufacturer would maybe require different port sizes, but PIPESIM still calculates the same optimal production. Therefore the choice of type is not that important as long as it is casing sensitive. Now PIPESIM is able to calculate a gas lift performance curve.

Lift Gas Response Curves

Outlet Pressure: 130 psia

Injection Gas Surface Pressure: 1000 psig

Injection Gas Surface Temperature: 65 F

Max Allowable Injection TVD: 9393 ft

Inj. Gas SG: 0.64

Gas Injection Depth:
☒ Optimum Depth of Injection
☐ Injection at Valve Depths Only

Sensitivity Data:
 Object: Gas Lift Data
 Variable: Min Injection Gas DP

	Values
Range...	psi
1	150
2	250
3	
4	
5	
6	
7	

Injection Gas Rate

	Values
Range...	mmscf/d
1	0.1
2	0.2
3	0.3
4	0.4
5	0.5
6	0.6
7	0.7

Run Model

System Plot...

Summary File...

Output File...

OK Cancel Help

Figure 14: Lift Gas Response Curve input layout

The result from the plot in the Figure 16 shows the well gets a significant production from gas injection.

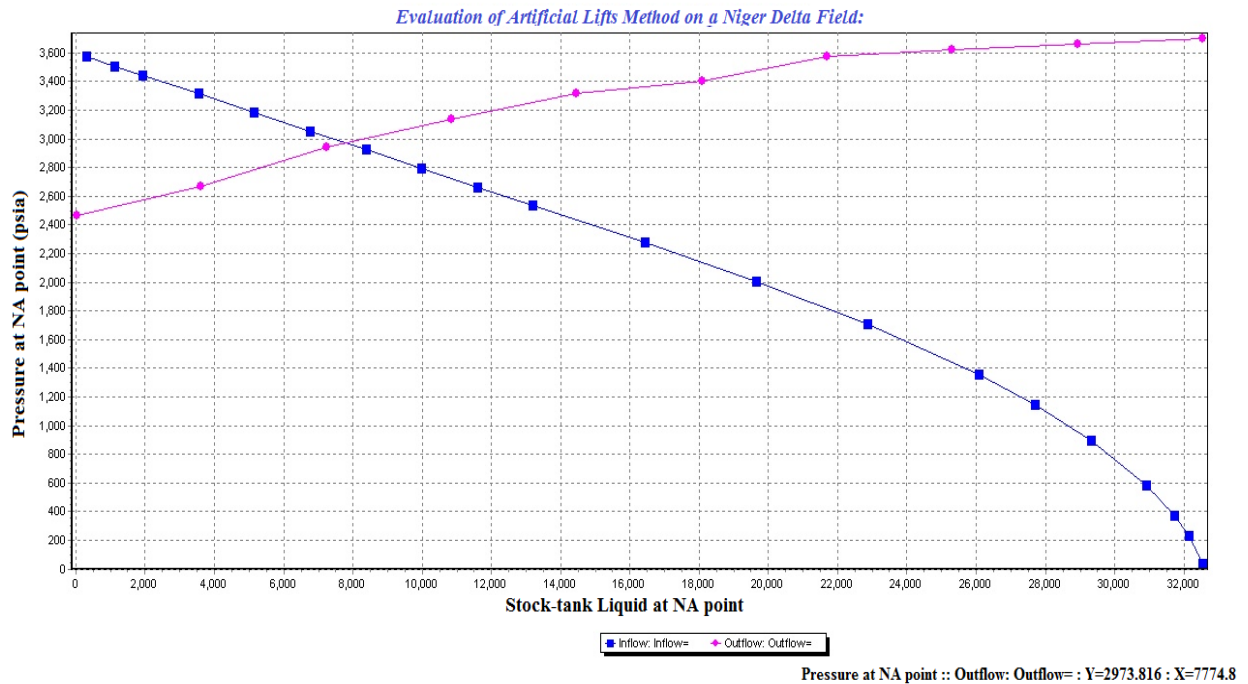


Figure 15: Production profile from gas injection

Table 3: Result from gas lift design on production

<i>Stock-tank Liquid at NA point (STB/d)</i>	<i>Pressure at NA point (psia)</i>
7774.8	2973.816

The well only needed one unloading valve. This is a combination of the operating valve setting depth, gas lift injection pressure and load fluid density. Also, Figure 16 shows the gas lift design summary and Figure 17 shows the gas lift design response.

Gas Lift Design - Summary

Proposed Design

☒ MD ☐ TVD

Calculated Production Rate at Target Injection Rate = 7728 STB/d

☐ Edit Depth ☐ Edit Valves ☐ Edit Temp

	Valve Depth	Valve Series	Port Size	Ptro	Open Pres at Surface	Close Pres at Surface	Gas Rate (unloading)	Unloading Liq Rate	Max Valve Throughput	Valve Temp
	ft			psig	psig	psig	mmscf/d	STB/d	mmscf/d	F
1	1887.8	BK-1	1/4	880	1000	895.2	0.468	3753	0.82	200
2	3395.5	BK-1	5/16	928.9	974	880.2	1.04	7051	1.14	260
3	4056.7	BK0	3/8	Orifice			1.25	7728	1.58	268
4										
5										
6										
7										
8										
9										
10										

Add... [Valve Lookup] Re-Design Graph...

Edit Selected Valve... Perform Re-Design Report...

Remove Selected Valve Install Design

Operating valve location is above static fluid level. Bracketing valves should be placed down to intersection of fluid gradient and gas gradient!

OK Cancel Help

Figure 16: Gas lift design summary

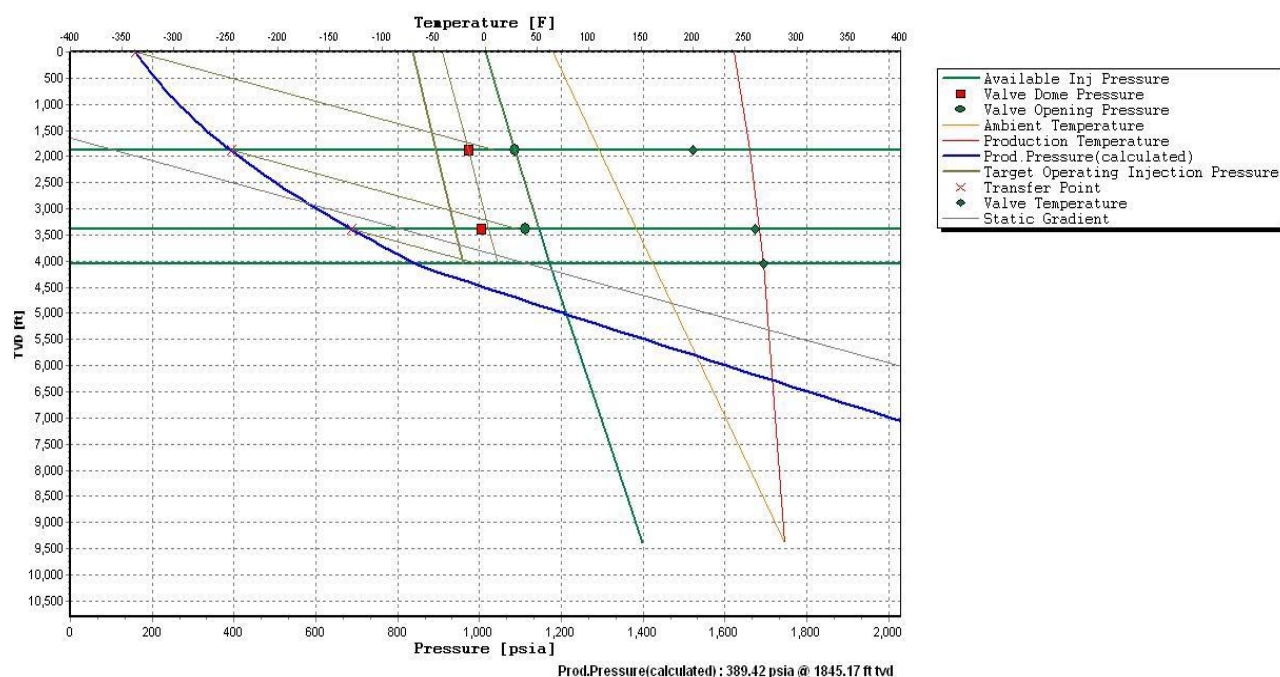


Figure 17: Gas lift design response.

Summary

The results of the plots show that the ESP solution gives a superior production rate compared to gas lift and the “base case”. The reliability of the production forecast is dependent of the reservoir pressure, and mostly the water cut. A small change in water cut gives a large change in oil production. The reservoir pressure is conservatively estimated, and the water cut trend is based on reliable reservoir simulations. In the well, it is assumed that there has not been a major water break-through yet, and the timing of this breakthrough involves some uncertainty. However, the same reservoir data source is used for the different scenarios, so the comparison of the two artificial lift methods should be valid.

CONCLUSION

Both ESP and gas lift gives production compared to the base case, but ESP is superior to gas lift in the considered well. It is reason to believe that the same difference would be seen in a full field artificial lift campaign. In this study the so called “ESP secondary effect” is not accounted for, this can increase production as well as the recovery factor for the field. So from a production point of view the ESPs is by far the best choice. The water cut behaviour is the biggest factor for change in the oil production. Expected lifetime of the ESP design on the hypothetical Niger Delta field is not accounted for.

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APPENDICES

Appendix A: Fluid Data

<i>Water Cut</i>	90%
<i>GOR</i>	449scf/stb
<i>Gas Gravity</i>	0.9
<i>Water Specific Gravity</i>	1.026
<i>Oil API</i>	30

Appendix B: PVT Calibration Data

<i>Range</i>	<i>Property</i>	<i>Value</i>	<i>Pressure (psia)</i>	<i>Temperature (°F)</i>
P = Pb	Sat. Gas	449scf/stb	2216	288
P = Pb	OFVF	1.33	2216	288
P = Pb	Life Oil Viscosity	0.54cp	2216	288

Appendix C: Wellbore Data

<i>Vertical Well</i>	
Perforation depth	9393
Flows is in:	4 $\frac{1}{2}$ " (3.958" ID) tubing from surface to 8200 ft.
	9 $\frac{5}{8}$ " (8.681" ID) casing from 8200 ft to 9393 ft.
Surface Ambient Temperature	68°F

Appendix D: Reservoir and Inflow Data

<i>Vertical Completion</i>	
Pressure (psia)	3625
Temperature (°F)	288
Productivity Index (stb/d/psi)	12.4

Appendix E: ESP Design Conditions

<i>ESP Design Conditions</i>	
Design Production Rate (stb/d)	10000
Design Wellhead (Outlet) pressure (psia)	130
Pump setting depth (ft)	8300 (within 9 $\frac{5}{8}$ " (8.681" ID) casing)
Design Frequency (Hz)	60
Design assumptions made: no gas separator, no viscosity correction and a head factor of 1.	

Appendix F: Gas Lift Design Conditions

<i>Design Control Parameters</i>	
Design Spacing	New Spacing
Design Method	IPO-Surface Close
Top Valve Location	Assume Liquid to Surface
Manufacturer	SLB (Camco)
Type	1" (Tubing size $2\frac{7}{8}$, $< 3\frac{1}{2}$)
Series	BK-1
Min Port Diameter	None
Unloading Temperature	Default (Unloading)
Production Pressure Curve	Production Pressure Model

Appendix G: Gas Lift Design Parameters

<i>Design Parameters</i>	
Kickoff Pressure	1000 psig
Operating Injection Pressure	1000 psig
Unloading Prod. Pressure	144.7 psig
Operating Prod. Pressure	144.7 psig
Target Injection Gas Flow rate	1.25 mmscf/d
Injection gas Surface Temp.	65°F
Injection Gas Specific Gravity	0.64
Unloading Gradient	0.465 psi/ft
Minimum Valve Spacing	Calculated
Minimum Valve Inj. Dp	150 psi
Bracketing Options	Not selected
<i>Gas Lift Safety Factors</i>	
Surface Close Pressure Drop Between Valves	15 psi
Locating Dp at Valve Location	50 psi
Transfer Factor	0
Place Orifice at operating valve location	Yes
Discharge Coefficient for Orifice	0.865