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Economic Evaluation of Electrical Submersible Pump (ESP) and Gas Lift Well For Production Optimization in A Niger Delta Field

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ABSTRACT

Gas lift system and Electrical submersible Pump's (ESP) are few of the artificial lift methods used to start up a well and or increase the producing life of oil / or gas wells. The principle of Gas lift is by lowering the hydrostatic pressure inside the production tubing through the injection of lighter fluid into the annulus. While the ESP gives an external pressure to the flow stream acting in series with the reservoir. GT oil field in the Niger Delta was used as case study, it has a production life span of eighteen 18 years. To increase GT production and extend the lifetime of the field, the operator decided to start an artificial lift project with an aim to optimize its production. To select the best artificial lift method to use, an economic evaluation was carried out using PROSPER for gas lift, ESP and a base case (Natural Flow) and then a production forecast with the different scenarios was done for six years. In technical comparison, PROSPER simulation results shows that both Gas lift techniques and the Electrical Submersible Pump (ESP) gave a higher production rates when compared with the Base Case (Natural Flow), and in terms of economic comparison, ESP generated the highest gross profit, but considering other factors like: water cut and replacement of failed pump, gas lift system was preferred for proper production optimization techniques. Hence, result from ESP indicated a faster reservoir pressure depletion and water encroachment. However, gas lift was chosen for GT based on the availability of readily compressed gas, higher life time expectance and lower installation and operational cost as compared with the ESP which had the highest production potential.

Keywords*: Gas lift, ESP, artificial lift, natural flow, production optimization, PROSPER, economic and sensitivity analysis*

1. INTRODUCTION

The oil and gas industry is a high risk and challenging venture but despite the risk involved in its operations, ranging from the exploration to the production phase; wells are still being drilled and completed for production. Some wells are drilled without hitting the target (oil), some are plugged and abandoned while others are producing successfully till date. Besides, some of these wells completed require an artificial lift at the beginning of the production to lighten the oil due to high fluid density or remove liquid loading in gas wells. Hence, the focus of this paper is to optimize well production from the reservoir to the surface production facilities via gas lift and electrical submersible pump (ESP). This will be achieved by designing a base case and then installing a gas lift and (ESP) to increase productivity index (PI) of the well and ensure longevity of the well conditions. Also, an economic analysis will be performed on the two artificial lift methods chosen for this paper and running sensitivity analysis on different parameters using PROSPER software.

There are different key factors that are considered prior to artificial lift installation in the field which include analysis of the individual well's parameters and the operational characteristics of the available lift systems. For the different pumps and lift systems available to the oil and gas industry, there are unique operational/engineering criteria particular to each system, but they all require similar data to properly determine application feasibility. Such as the inflow performance relationship, Liquid production rat, Gas-liquid ratio, Water cut, Well depth, Completion type, Wellbore deviation, Casing and tubing sizes, Power sources, Field location, Solids/sand, Reliability, Efficiency, Environmental impact etc. Each of the artificial lift systems has economic and operating limitations that rule out it consideration under certain operating conditions. Some types of lift equipment depending upon the type of installation, can have higher initial costs than others. Gas lift can have a high initial cost for a one or two well system where a compressor must be installed. For a large number of wells, gas lift may become economical. Hydraulic pumping becomes less costly where several well can be operated from a central system.

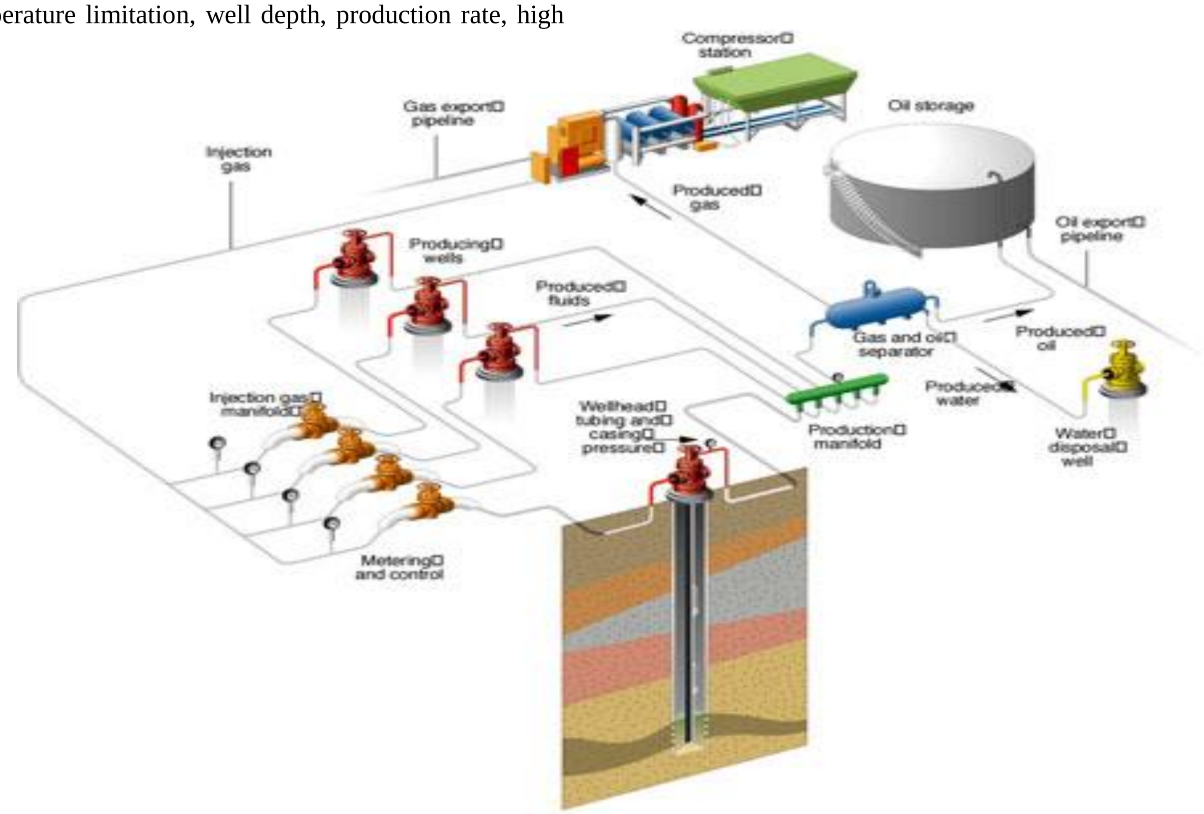
Clegg (1988) mentioned some economic factors such as: revenue, operational and investment costs as the basis for Artificial Lift selection. He believed that the selected Artificial Lift method could have the best production rate with the least value of operational costs. He also carried out a studied on some operational and designing characteristics of Artificial Lift methods and found that the operational costs and production rate are affected by these factors. Alemi et al. (2010) used "TOPSIS" model to analyzed one of the Iranian oilfields and found ESP pump employment as the optimum artificial lift method. Abdel-Wally *et al.,* (1996) optimized the gas lift process in Gulf of Suez Field, and resulted production increase from 17,000 bbl. /day of oil to 19,000 bbl/day. Ayatollahi *et al.,* (2001) 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 method was used to determine optimum injection depth, optimum well-head pressure, optimum production rate and minimum injection gas volume as well as the appropriate valve spacing. General Guidelines from Weatherford International Ltd., (2005) summarizes typical characteristics and applications for each form of artificial lift. These are general guidelines, which vary among manufacturers and researchers. Each application needs to be evaluated on a well-by-well basis. Heinze *et al*. (1995) used a decision tree to evaluate artificial lift selection based on a longtime economic analysis which considered primary investment, operational costs, and life time cost and energy efficiency. Camponogara and Nakashima (2006) 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.

2. CHALLENGES OF LIFTING OIL AND GAS FROM THE RESERVOIR

One of the challenges faced in lifting the oil and gas from the reservoir via the production tubing to the surface facilities is an unnecessary production decline which is a serious problem in the petroleum and gas industry today. This decline may be as a result of mismanagement of wells, excessive pressure drops along the production system, oversized or undersized tubing, and improper perforation method etc. A change in a single component of the production system may lead to a change in the pressure drop behavior of the other components since the various components are interactive. In addition, for the fact that artificial lift installed in wells increases the production rate, there are some problems encountered after the installation of these lifting methods to help recover the column of fluid to the production facilities at the surface. Such as flowing pressure and temperature limitation, well depth, production rate, high GOR, electrical power, space, economics etc. which are factors to consider in the selection prior to the installation. Hence, this study presents a sensitivity analysis on these factors for production optimization.

3. GAS LIFT SYSTEM

If there are gases available for injection either from an associated or non-associated gas reservoirs with a surface compression plant installed, gas lift is one of the most versatile process used to artificially lift oil from wells where there is insufficient reservoir pressures to produce the well. The process involves injecting gas through the tubing-casing annulus. Injected gas aerates the fluid to reduce its density; the formation pressure is then able to lift the oil column and forces the fluid out of the wellbore. Gas may be injected continuously or intermittently, depending on the producing characteristics of the well and the arrangement of the gas-lift equipment. To enhance the financial revenues this operation has usually always been a subject for optimization to reach the most rewarding design before its operational establishment. Hence, production optimization aims at increasing the rate at which a well flows from the reservoir to the stock tank. Thus, production optimization through nodal analysis is a way of preparing a well for the production of oil and gas from the reservoir so as to achieve the greatest possible efficiency. It has been concluded that genetic programming is fully capable in aiding faster gas lift optimizations while is also stable and applicable to a very broad range of operating conditions. The merits and draw backs are finally compared with the neural network approach. Khamehchi, *et al* (2009). Figure 1 shows a schematic of a gas lift system.



Artificial lift components. Courtesy: Schlumberger.

Figure 1: Gas lift system

Source: www.oilandgasonline.com

4. ELECTRICAL SUBMERSIBLE PUMP SYSTEMS

Electrical Submersible Pump systems incorporate an electric motor and centrifugal pump which is a dynamic device that use kinetic energy to increase fluid pressure unit which run on a production string and connected back to the surface control mechanism and transformer via an electric power cable. The downhole components are suspended from the production tubing above the well's perforations. In most cases the motor is located on the bottom of the work string. Above the motor are the seal section, the intake or gas separator, and the pump. The power cable is clamped to the tubing and plugs into the top of the motor. As the fluid comes into the well it must flow past the motor and into the pump this fluid flows past the motor, aids in the cooling of the motor. The fluid then enters the intake and is taken into the pump. Each stage (impeller/diffuser combination) adds pressure or head to the fluid at a given rate. The fluid will build up enough pressure, as it reaches the top of the pump, to be lifted to surface and into the separator or flow line. The nature of ESPs design (figure 2) makes them fit inside small wellbores, still being able to deliver high pressure increments. They are successful when handling liquids, ranging from low to medium viscosities. Their performance is characterized by the relationship between the pressure increment over the pump and the flow rate through the pump, for a certain rotational speed.

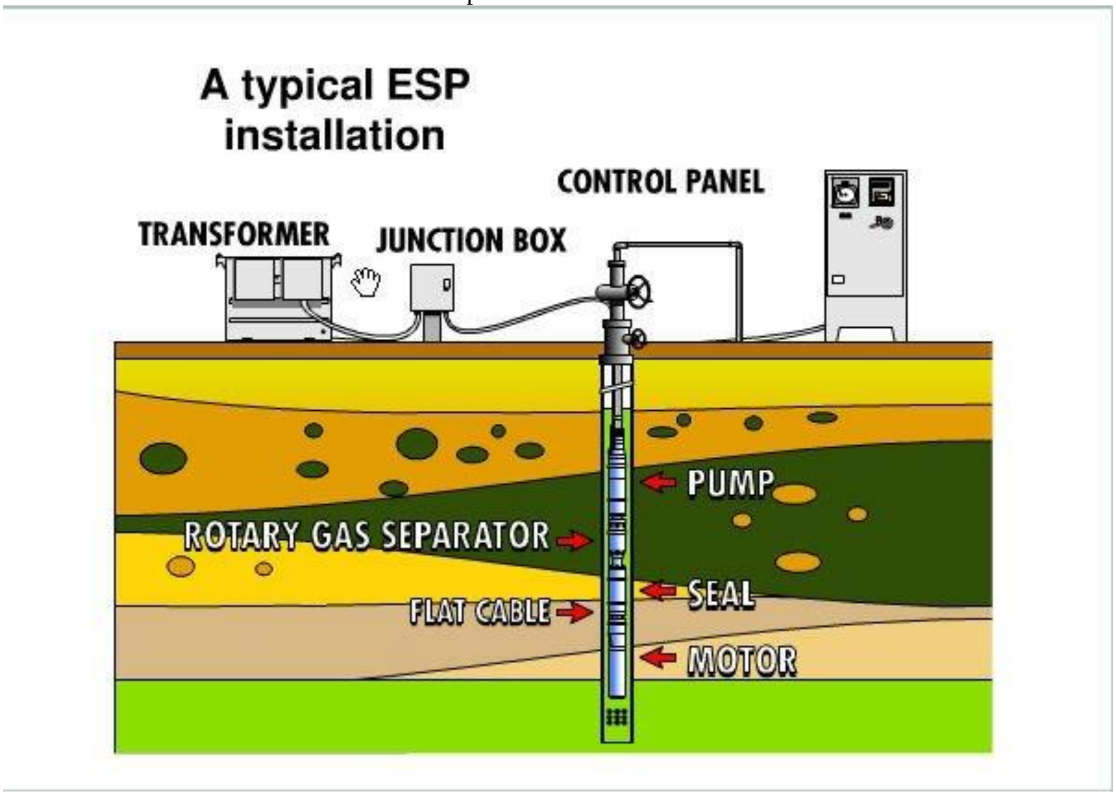


Figure 2: Schematic of an ESP system Source: www.alibaba.com

5. BUSINESS AIM AND OBJECTIVES

The goal of every business is to maximize profit in a safe and economic way. Thus, this paper is aimed at economic evaluation of electrical submersible pump (ESP) and gas lift selection for production optimization in a GT Niger Delta oil field with an objectives to maximize profit from this oil field on a day-to-day basis. This focuses on:

(1) Building a model using PROSPER software to determine the production potential of both artificial lift methods and the base case "natural flowing well".
(2) Carry out economic analysis on Gas lift and ESP and also, a cost benefit analysis of changing various components of the system resulting from the optimization exercise.
(3) To develop with time the production forecast of both Gas lift and ESP method and make a comparison with the base case.
(4) To select the best option for the artificial lift method for the case scenarios.

6. OVERVIEW OF PROSPER

PROSPER is a well performance, design and optimization program for modelling most types of well configurations found in the worldwide oil and gas industry today. It can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed. PROSPER's sensitivity calculation features enable existing well designs to be optimized and the effects of future changes in system parameters to be assessed.

PROSPER is designed to allow building of reliable and consistent well models, with the ability to address each aspect of well bore modelling viz; PVT (fluid characterization), VLP correlations (for calculation of flowline and tubing pressure loss) and IPR (reservoir inflow). By modelling each component of the producing well system, the User can verify each model subsystem by performance matching by tuning the well system model to the real field data (PROSPER User Manual, 2008). Figure 3 represents a workflow of artificial lift design for production optimization in PROSPER.

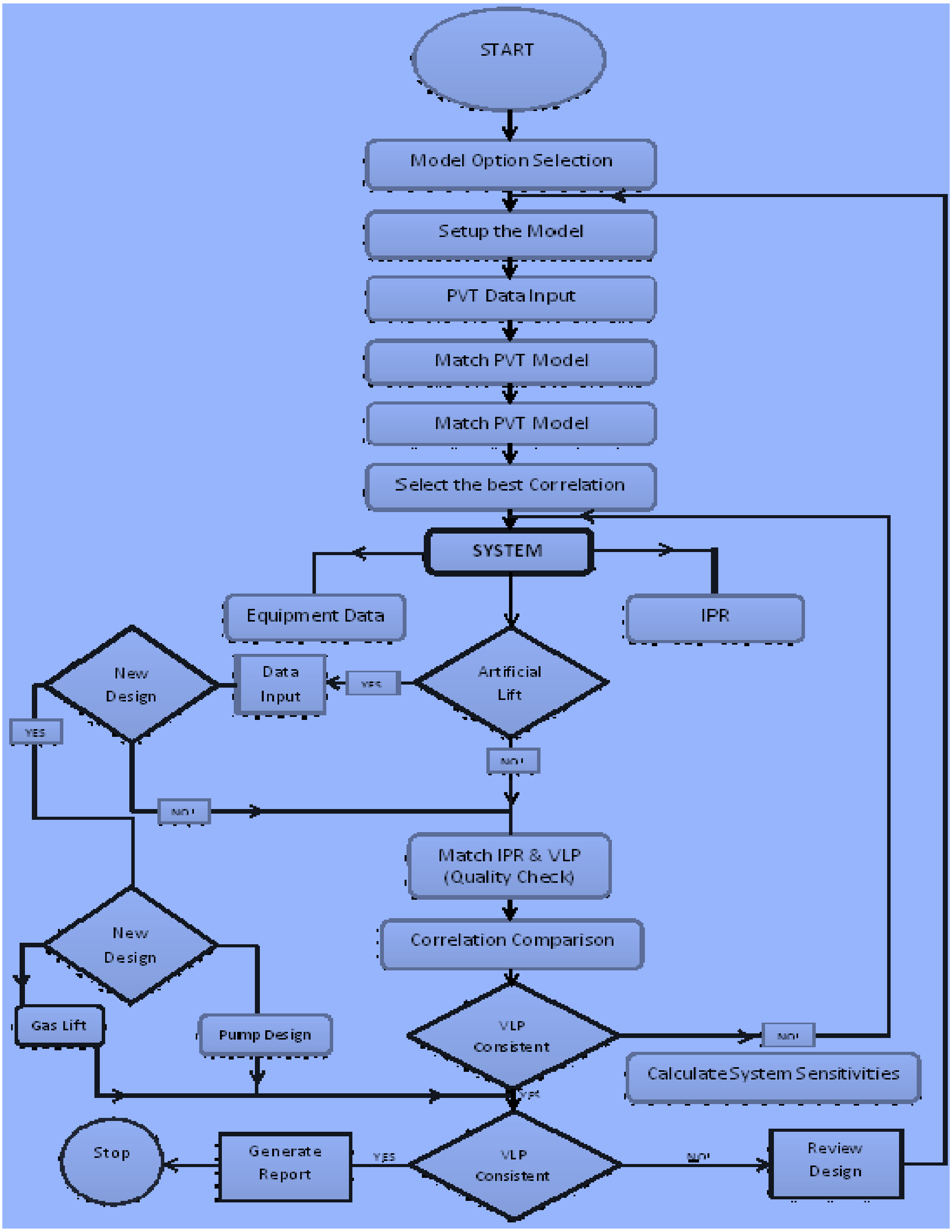


Figure 3: Artificial lift design workflow in PROSPER

7. RESULTS

The system option was setup in PROSPER for the various scenarios of Gas lift and ESP. In this paper, a complete PVT laboratory data was not available hence PVT correlation in Prosper was match to select the best option for GT field. The available PVT data are given in Table 1 and results are presented below. PROSPER uses a non-linear regression to select the best correlations by applying a multiplier (Parameter 1) and a shift (Parameter 2) to each correlation. Glaso correlation was selected for bubble point pressure, solution gas oil ratio and oil formation volume factor while Beggs et al was selected for oil viscosity based on the multiplier and the shift.

Table 1: PVT Data

T	220 deg F
Pb	3256 psig
Rs	820 scf/STB
oil gravity	37 deg API
gas gravity	0.874
water salinity	160000ppm
oil viscosity	0.428 cp
Oil FVF	1.4782 rb/STB

The result of the IPR curve was validated with test data (Table 2) from the field at low and high rate. This was done to ascertain that the test point matches the intercept of the IPR and VLP curves from the mathematical model used to develop the software. Figure 4 a shows the inflow performance relationship of WL 14 with skin of 4 which gave an absolute open flow potential of 28593.2 stb/day and productivity index of 11.94stb/day/psi.

Table 2: Test Data

comment	WH FP	WHFT	WOC	Liquid rate	Guage depth	Guage press	Reser. press	GOR
low rate	930	134	15	7200	11000	3940	820	0
high rate	290	157	15	12000	11000	3330	820	0

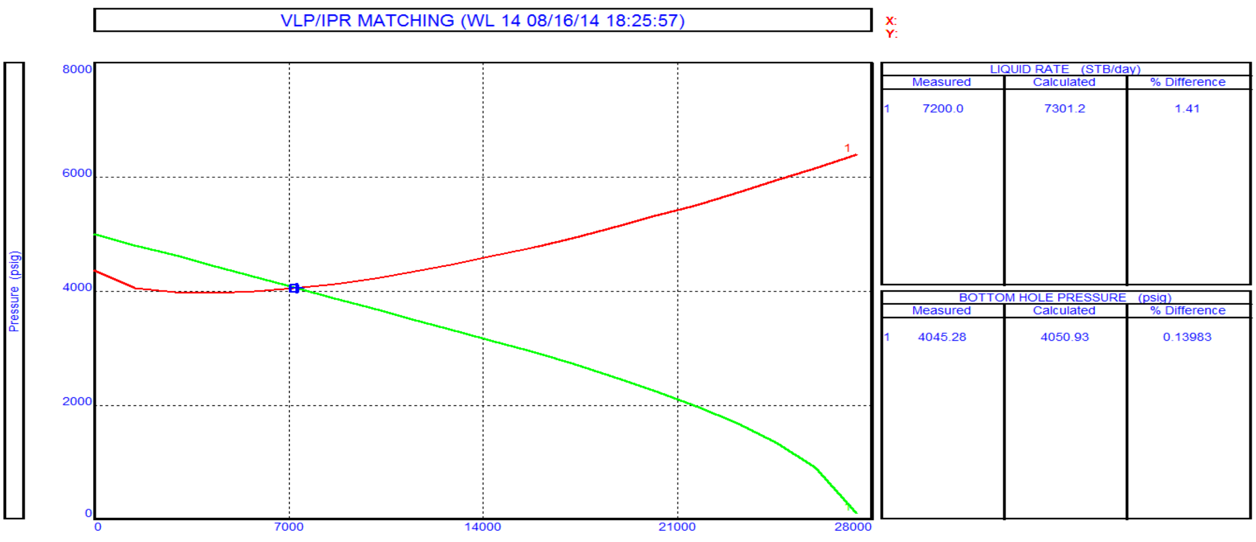


Figure 4: Inflow performance relationship and outflow performance match with test data of WL 14

In matching the vertical lift performance, the multiphase flow correlation was tuned in order to match a downhole pressure measurement so that the intersection of VLP/IPR will match the production rate as per well test. The available parameters for matching depend on the IPR model in use. For Darcy-IPR model selected for this study, permeability, skin or pressure could be used. Thus, pressure was adjusted to match the IPR and the GOR was check to make sure test data is same with PVT data since the reservoir is still undersaturated.

8. GAS LIFT PERFORMANCE CURVE

The performance curve of a gas lift design plots the oil rate produced with increased gas injection rates. The greater the amount of gas injected; the lighter will be the fluid column. However a stage reaches in the injection when any further increase in gas injection will increase friction component more than it will decrease gravity component. After this stage any increase in gas injection will decrease production rates. Thus the performance curve will go up and then come down as shown in figure A1 of the appendix. Looking at the performance curve we see that at a gas lift rate of 5 MMscf/day the oil production is around 1507stb/day. The maximum oil production of 1579 stb/day occurs for gas lift rate of approximately 8.2MMscf/day. This represent the optimum gas lift rate for well WL 14. In case the available gas is higher than the optimum gas required, the program will only inject the optimum gas into the well, which is 8.2MMscf /day in this case.

Table 3: Result of gaslift design rate

GLR Injected	Liquid Rate	Oil Rate	VLP Pressure	IPR Pressure	Standard Deviation	Design Rate	Oil Rate
scf/STB	STB/day	STB/day	psig	psig		MMscf/day	STB/day
1054.14	11214.5	2242.9	3830.81	3640.6	9.17956	5	2162.3

For WL 14, REDA GN10000 5.13 inches (8000-12000 RB/day) was selected from the list of suitable pumps. The pump needs 9 stages and requires 28.62 HP at the design rate. From the list of suitable motors, ESP_Inc 540_70 30HP 435V 45A and Figure 5 display the design operating point superimposed on the pump performance curve:

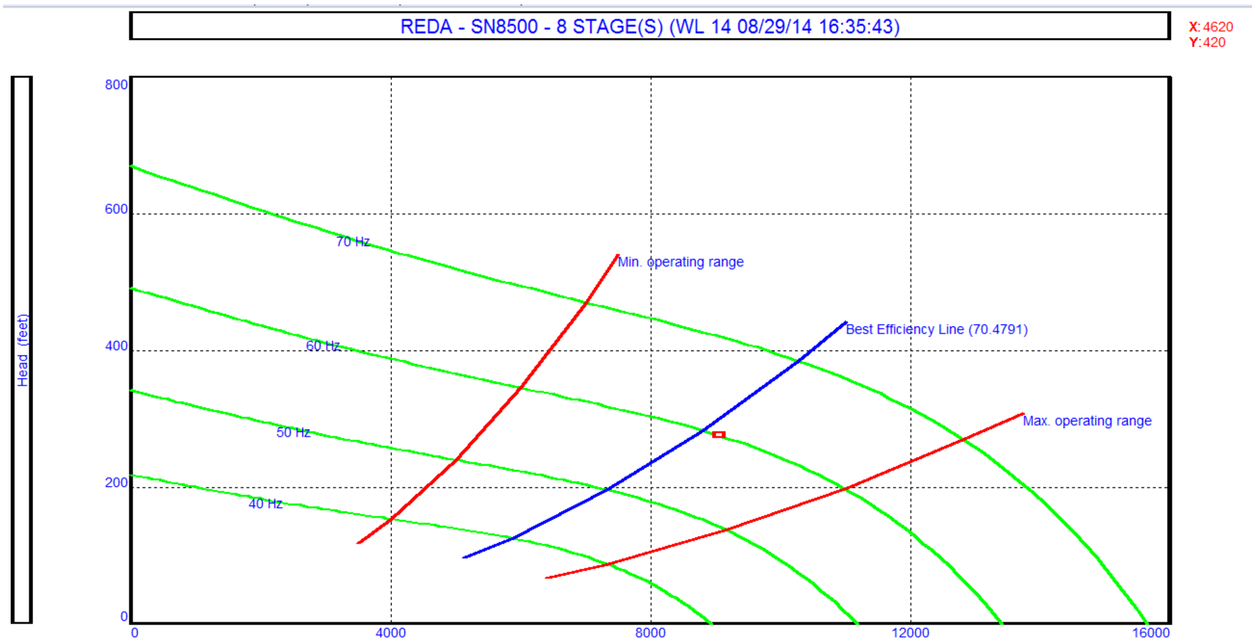


Figure 5: REDA-SN8500 operating point

The pump (red box in figure 5) is being run a little above the best operating line and close to its maximum output; perhaps the next biggest pump would be a better choice, especially if the pump is expected to handle a greater lift duty due to increasing water cut during the pump's run life. Hence, REDA HN13500 with 6 stages was selected with the same motor and cable as shown in Figure 6. This pump operation is close to its optimum efficiency and has some excess head.

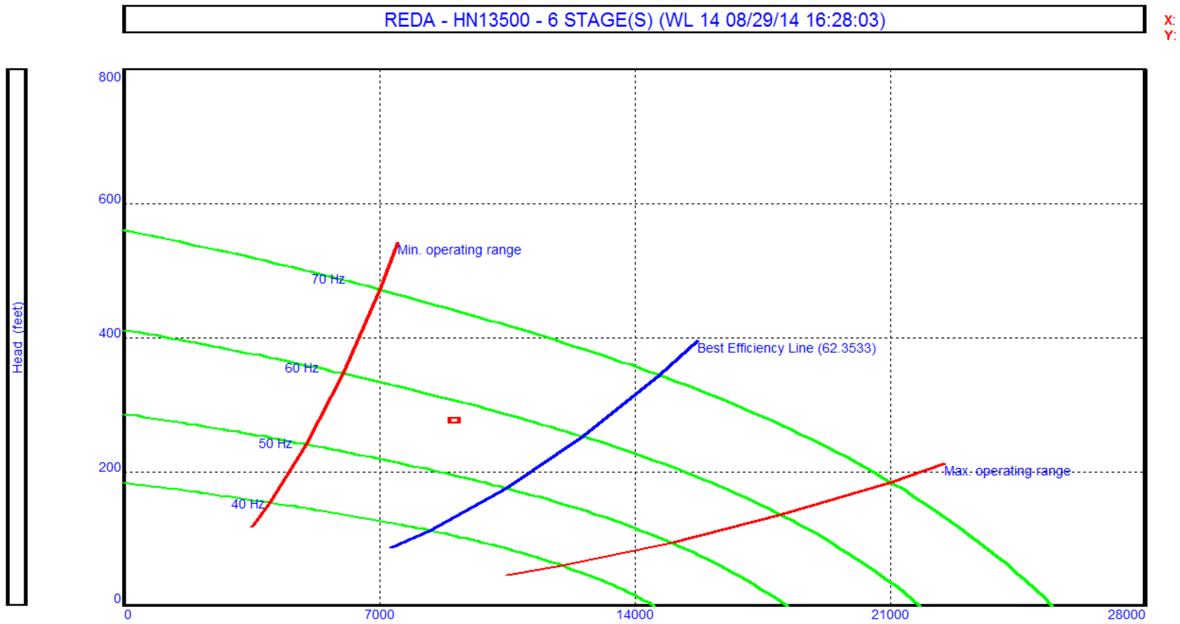


Figure 6: ESP Sensitivity

9. RESULT OF PRODUCTION FORECAST OF THE NATURAL FLOWING, THE GAS AND ESP WELLS

Table 4: Production rate performance

				Total liquid rate (bbl/day)			Oil Rate (bbl/day)		
Parameter /year	**Gas-oil ratio**	**Water-cut**	**Pressure (psi)**	**Natural Flow**	**Gas Lift**	**ESP**	**Natural Flow**	**Gas Lift**	**ESP**
2008	820	60	4246	7589.28	11814.5	15449.4	4553.568	7088.7	9269.64
2009	820	65	4045	7301.2	10493.7	14344.7	4745.78	6820.905	9324.055
2010	820	67	3906	7049.28	9635.5	12721.1	4723.018	6455.785	8523.137
2011	820	70	3878	6808.94	9216.84	11351.6	4766.258	6451.788	7946.12
2012	820	71	3678	6430.1	8854.3	10493.7	4565.371	6286.553	7450.527
2013	820	72	3608	5945.86	8413.94	9702.84	4281.019	6058.037	6986.045

The result of the production forecast show that ESP solution gives a superior production rate compared to gas lift and the natural flowing case “base case”. From figure A1, it is observed that the gas lift production rate is close to the ESP production rate within 2012-2013 which probably indicate that the pump might be failing to meet its design rate due to changes in the reservoir properties and such needs another pump to handle the current conditions of the reservoir. ESP fails in higher water cut.

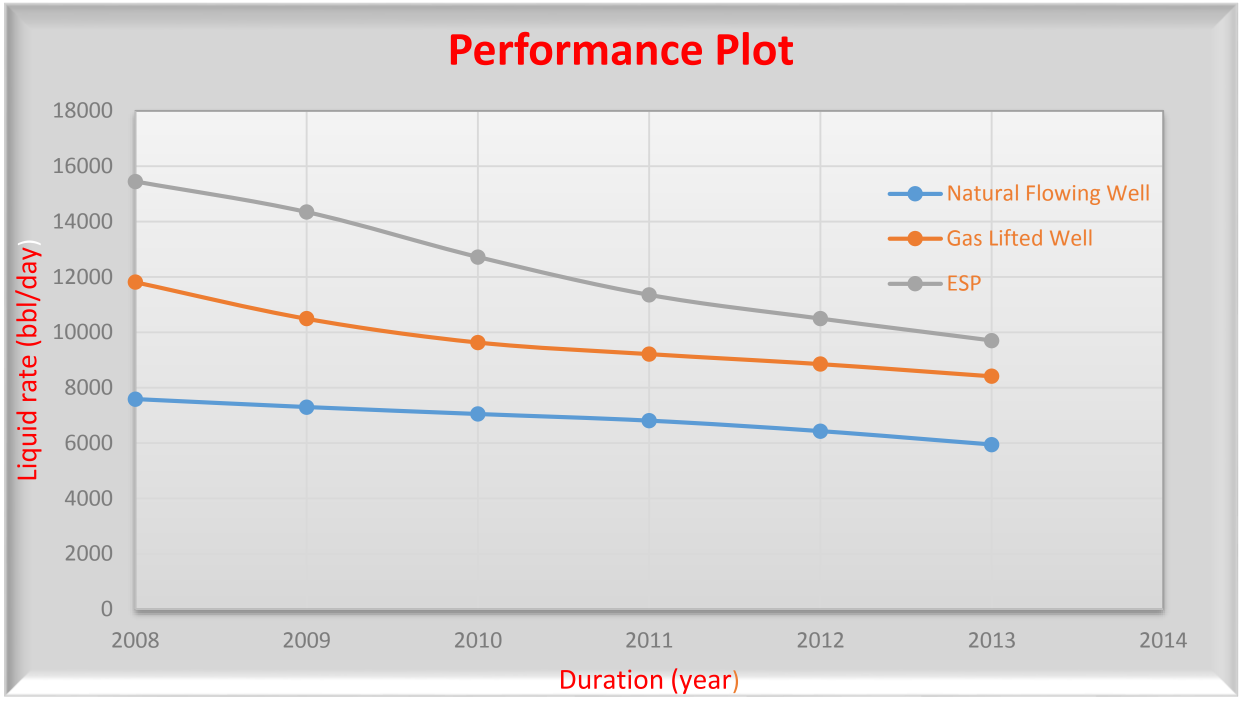


Figure 7: Production performance of base case, ESP & gas lifted well

The production trend from the graph shows a gradual decrease in production rate over the years for gas lift system as compare to the ESP case where there is sharper drop in production. These two cases gave an increase in production when compare with the base case. The total liquid rate falls beneath 10000 bbl/day after 2013 in the "ESP case". This is just a little below the best operating range of the pump running close to 60 Hz. When this gets close to the minimum operating point, the pumps have to be run at a lower frequency (Figure 6). When the pumps fail, there should be a new analysis with the current conditions to see if another pump design would fit better. After running some years one would also learn more about the rates and how the reservoir responds to the pumps.

10. SENSITIVITY ANALYSIS

For an effective optimization of a system, there is need to carry out sensitivity analysis on the key parameters affecting the productivity of the wells been optimized either via lifting or pumping method. In this study four parameters were used in the PROSPER sensitivity analysis for production optimization. These are water cut, pressure, tubing diameter and skin. The summary of the sensitivity results are shown in appendix B.

From the sensitivity analysis on the effect of water cut, tubing diameter and skin, the liquid flow rate is highest at water cut 0%, skin of 0%. The value of the liquid flow rate obtained with the water cut and skin are 14773.5 STB/day for 3.958 inches and 20205.8STB/D for 4.892 inches. In reality, this is not possible to achieve because even after success stimulation job to reduce the skin value to zero, there will be possibility of increase in water cut since the well is still producing. Thus,

other options are available for management consideration. For ESP system, despite the fact that it gives the maximum production, it is highly affected by water cut which will lead to redesigning another pumping system that will handle the current reservoir conditions.

11. ECONOMIC ANALYSIS

Before making a final decision on which method of artificial lift to be used, a thorough economic analysis needs to be carried out. It is the profitability of a project that has to be the final decision criteria. This study is still in the evaluation phase, and a full economic analysis giving the NPV of the projects is not available yet. The NPV will give the value of a project through its entire lifetime taking capital costs, operating costs, depreciation and revenues into account. However, the initial costs of the scenarios are analyzed and can give a good indication of the project magnitude. Table 5 shows the capital cost e.g. the cost until end of installation of each project. This involves cost of procurement, construction, engineering, administration and operational cost during installation (rig rate etc.). The amounts do not include company costs such as company personnel, helicopter, catering etc.

Table 5: Gas-Lift System and ESP Estimated Cost per Item

Items	Cost $
HP	3000
Equipments	50000
Installation	20000
Running cost/year	3000000
Maintenance cost/year	400000
Water Treatment/year	350000
Barrel of oil	40

If we assume $40 per barrel of crude oil, then the estimated cost for six years is tabulated as shown in table 6.

Table 6: Gas-lift and ESP Estimated Cost for six years

For six years	Gas-lift	ESP
Item	Cost, $	Cost, $
Horsepower	1478516	5043032
Installation	70000	100000
Equipment	300000	250000
Running cost	18000000	18000000
Maintenance	2400000	3,200,000
Water Treatment	2100000	2100000
Sum	24,348.516	28,693.032

Table 7: Estimates of oil revenue

Items	Natural Flow	Gas Lift	ESP
Oil Rate (bbl/6yrs)	840104.42	1090517.74	1504785.52
Revenue ($/6yrs)	33604176.78	43620709.60	60191420.94
Installation/Operating cost ($)	20,500000	24,348.516	28,693.032
Gross Profit ($)	13,104,176.78	19,272,193.60	31,498,388.94

From the economic analysis on table 7, we conclude that the cost of ESP is higher than gas lift and this justified it efficacy in the production increase as compared with the gas lifted and natural flowing case. The overall performance gave ESP the best in terms of production increase and gross profit but if we consider other factors in the cause of running this artificial lift methods, we might consider gas lift as an option for production optimization techniques since ESP failure requires a new pump to be design and installed to meet the current operation conditions of the reservoir. Also, gas lift may be preferable if an existing gas compressed station is located close to the GT oil field with the availability of gas for injection.

12. CONCLUSIONS

Through consideration of the production profile, desired rate and advantages /disadvantages of gas lift and ESP for production optimization to compare the most suitable artificial lift methods for GT field in the Niger Delta, the following conclusions were drawn:

Both gas lift and ESP gave a large increase in production when compared with the base case, but ESP is superior to gas lift for well WL14. It is reason to believe that the same difference would be seen in a full field artificial lift campaign. In this paper, from a production point of view and gross profit, the ESPs are by far the best choice. Note that the cost of implementing ESP is higher than that needed for Gas-lift implementation.

Implementation of ESPs carries greater risk because of the complexity of the equipment and limited lifetime. When ESPs fail this require a full workover, which is costly mainly because of the required rig operation compared to a wireline operation. However, there are design choices and running procedures that will extend the lifetime. Monitoring production and the pump during operation is crucial to achieve extended lifetime. Sand production and scale is two of the biggest risks. Expected lifetime of the dual ESP design on this field is 2 years. However, for a gas lift once installed and it is operating, the maintenance is less complex compare to the ESP.

Comparing cost and production potential of the artificial lift methods, ESPs are the best choice. The pilot project well WL14 would return invested capital in less than a year due to its high production potential compared to the base case. But before a final decision is made an economic analysis of each project's lifetime should be carried out. The ESP projects will generate higher costs later in life than the gas lift project. Hence, NPV evaluation will account for all costs and depreciation of each project.

13. RECOMMENDATIONS

Based on the analysis of the production performance for both gas lift and ESP of GT field, the following recommendations were made:

Based on the economic 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 to the ESP artificial lift method in GT field.

Based on failure rate, maintenance (workover), greater risk, complexity of the equipment and limited lifetime for ESP, gas lift was recommended for GT field which has an expected life span of 18 years.

However, a full economic analysis should be carried out over the life span, considering NPV evaluation for all costs and depreciation of each project. Based on the results, it is suspected that the ESP projects will generate higher costs later in life than the gas lift project assuming it is installed for many wells.

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.

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Appendix A

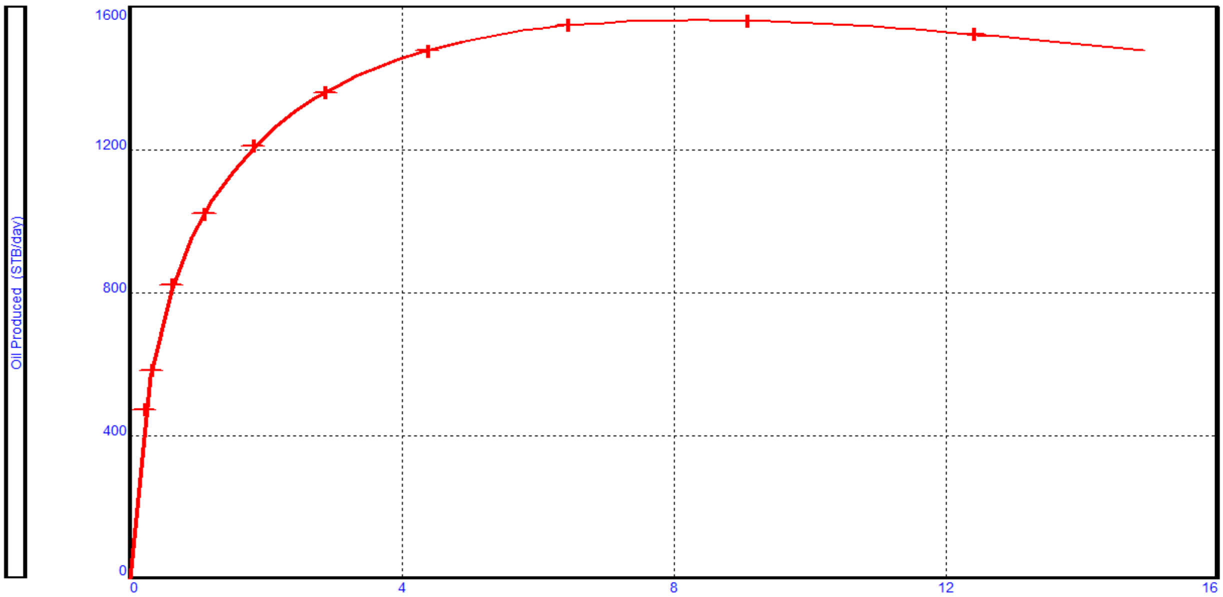

Figure A1: Gas lift performance curve

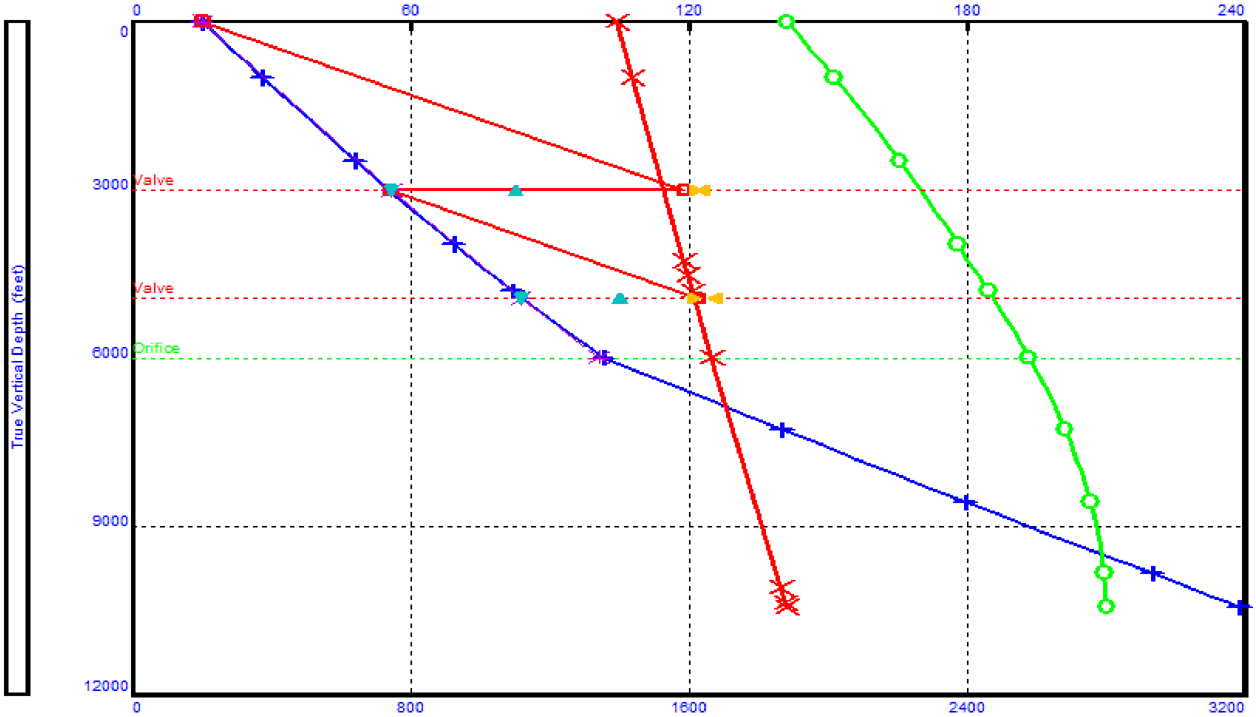

Figure A2: Gas lift design gradient plot

Appendix B

Table B1: Effect of WOC, skin & tubing diameter on liquid rate

WOC	SKIN	TUBING DIA	LIQUID RATE
0	0	3.958	14773.5
40	0	3.958	13530.8
80	0	3.958	9405.2
0	2	3.958	13583.8
0	4	3.958	12533.6

Table B2: Effect of pressure, skin & tubing diameter on liquid rate

SKIN	PRESSURE	TUBING DIAMETER	LIQUID RATE
0	2500	3.958	2328.9
2	2500	3.958	1942.2
4	2500	3.958	1669.5
0	3000	3.958	5615.5
2	3000	3.958	5061.4
4	3000	3.958	4583.5
0	4000	3.958	10493.7
2	4000	3.958	9625.5
4	4000	3.958	8854.3

Table B3: Effect of WOC, skin & tubing diameter on liquid rate

WOC	SKIN	TUBING DIAMETER	LIQUID RATE
0	0	4.892	20205.8
40	0	4.892	18093.6
80	0	4.892	11284.4
80	2	4.892	9409.1
40	2	4.892	15449.4
0	2	4.892	18005.4
40	4	4.892	14240.7
80	4	4.892	8003.1

Table B4: Effect of pressure, skin & tubing diameter on liquid rate

SKIN	PRESSURE	TUBING DIAMETER	LIQUID RATE
0	2500	4.892	3689.2
2	2500	4.892	2990.3
4	2500	4.892	2316.4
0	3000	4.892	7726.4
2	3000	4.892	6704.2
4	3000	4.892	5883.9
0	4000	4.892	14344.7
2	4000	4.892	12701.1
4	4000	4.892	11351.6

Table B5: Effect of pressure & WOC on liquid rate for ESP

WOC	PRESSURE	LIQUID RATE
70	4000	8223.4
80	4000	7831.9
90	4000	7349.5
70	3500	6881.1
80	3500	6881.1
90	3500	6212.2