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ECONOMIC EVALUATION OF SELECTED ARTIFICIAL LIFT METHODS IN A MARGINAL OIL FIELD IN THE NIGER DELTA

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ABSTRACT: *Marginal fields require production optimization and proper management due to uncertainties surrounding the size, reserves and operational strategies and costs. One of the ways of achieving optimal development is by using an efficient artificial lift method early or later in the field life, that will increase recovery and profitability. However, knowing the best artificial lift method to use for a situation could sometimes be challenging. In this study, a techno-economic comparison of Continuous Gas Lift (CGL) and Electrical Submersible Pumps (ESP) was carried out for a marginal oil field in the Niger Delta to choose the optimal method. Well and reservoir models were built to generate production forecasts under natural flow, CGL and ESP. Economic models were formulated, incorporating cost for each artificial lift method, oil price and estimated revenue from oil and gas sales to determine the Net Present Value (NPV), Internal Rate of Return (IRR) and Profitability Index (PI). Risk and sensitivity analyses were carried out. When natural flow was not feasible and artificial lift preferred, CGL was characterized by high initial capital while ESP tended to have higher operating cost. Ultimate Recovery (UR) increased by 8.6% with the use of ESP but by 6.7% with CGL. The ESP also gave an NPV of $1.48 Million, IRR of 46.0% and PI of 1.50 while CGL gave an NPV of $2.03 Million, IRR of 31.4 and PI of 1.49. Higher profits were obtained when the artificial lift methods were installed after natural flow had been exhausted. Profitability of the marginal field using artificial lift was affected by oil price, fiscal terms and the cost of the lift methods.*

KEYWORDS: Marginal fields, Niger Delta, Artificial lift, Profitability criteria, Fiscal terms

INTRODUCTION AND LITERATURE REVIEW

Marginal fields are small and abandoned fields, which have remained undeveloped because their economic sensitivity. However, they could be profitable if operated at relatively low overhead and operating costs (Adamu et al, 2013). According to the Society of Petroleum Engineers (SPE), marginal fields are discoveries which have not been exploited for long, due to factors such as: very small sizes of reservoirs/reserves, lack of infrastructure in the vicinity, prohibitive development costs, unfavorable fiscal regimes and technological constraints. Svalheim (2004) opined that a marginal field that may not be profitable for development at a given time could become commercially viable under some technical or economic changes.

For many years, marginal fields received little attention in the industry due to the focus on challenging issues such as reservoir size, flow rates, capital and operating expenditures. However, it is now widely accepted that developing marginal fields has more to do with economics rather than reserves or production characteristics (Aldrich and Kinney, 2000). Many oil producing countries have therefore carried out reforms aimed at reducing the economic burden and making investment in marginal fields more viable.

In Nigeria, Abegunde (2013) outlined the major reasons for the interest of the Nigerian government in marginal fields development to include: reducing the rate of abandonment of

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mature fields, encouraging indigenous participation in the oil industry to build competence and wealth and increasing government's take via royalty and taxes in hitherto non–producing fields. However, Egbogah (2011) has noted that despite concerted efforts, there are still technical, financial and political challenges facing marginal field development in Nigeria

Marginal fields are often characterized by either relatively low productivity or poor recoveries. Many of the fields flow naturally in the early producing days but require that the natural energy be supplemented by artificial lift to optimize production (Khalil and Rai, 1991).

Artificial lifts, generally applied to wells that are not able to produce naturally or wells whose rates are considered uneconomical, fall into two groups: use of mechanical pumps to assist production by reducing pressure drop along the well, or the lightening of the hydrostatic column by injecting gas into the production tubing. There is no single artificial lift method that can be applied economically for all types of wells (Heinze et al, 1995); hence selecting an artificial lift method for any field depends on the mechanical limits, operational issues, capital and operating costs. (Clegg et al, 1993). Improper selection of artificial lift can reduce production, recovery and profit substantially.

According to Lea and Nickens (1999), selection criteria for artificial lift methods could include: consideration of depth/rate relationship, relative operational advantages and disadvantages, recommendation by expert programs and economic evaluation. Steele (1976) studied the application and economics of artificial lift in the Judy Creek Field, Alberta. The study compared gas lift, sucker rod pumping and electrical submersible pump. Electrical submersible pump (ESP) gave lowest initial capital investment per well, but was found to be susceptible to high failure rates and hence high operating cost. Gas lift gave the highest net present value. In 1991, Kahali et al. studied the use of artificial lift methods for marginal fields in offshore India. Among the different methods studied, gas lift and ESP were found to be the only applicable methods in the fields because of location, depth and anticipated rates. Gas lift was recommended as the most effective method based on the initial capital investment and operating costs.

Naguib et al. (2000) reported that although production rates for gas lift is often lower than for ESP, the cost per barrel of ESP could be higher. However, ESP could be a preferred option where supply of quality lift gas is an issue.

Ramirez et al. (2000) carried out a techno-economic evaluation of artificial lift systems for eight offshore fields in southern Gulf of Mexico. Gas lift and ESP were ranked best based on their power consumption against possible production rates. However, GL gave the highest NPV due to high cost of ESP equipment and relatively frequent failure rates. Ceylan, (2004) studied the choice of artificial lift method for oil wells in a Turkish field. A detailed technical and economic evaluation was carried out on ESP and Sucker Rod Pump (SRP) over a 10-year producing period. The study observed that ESP gave a higher IRR compared to SRP and increasing the number of wells producing with ESP systems increased the rate of return. Soponsakulkaew, (2010) developed a decision matrix screening tool for identifying the best artificial lift method for liquid-loaded gas wells. It reported that ESP gave the highest NPV and IRR because of the low initial cost of investment compared to other methods.

The review of literature showed that no single indicator can effectively be used to select artificial lift method at all times. Specific situations must be properly evaluated and using two or more economic indicators could give better insight into the profitability of the investment.

ISSN: Print 2514-9253, Online 2514-9261

METHODOLOGY

A commercial simulator (PROSPER) was used to design the well under natural flow and using ESP and CGL methods. A simple sector reservoir model was built with the aid of the IMEX builder tool of the Computer Modelling Group reservoir simulator. Fluid properties were modelled using standard correlations. An active underlying bottom aquifer was assumed for the homogeneous reservoir. For the relative permeability estimation, a three-phase oil-water-gas system was assumed and Stone's second model was used to generate appropriate relative permeability Tables and curves. The reservoir, well completion and fluid data are listed in Table 1, while aquifer and relative permeability data are listed in Tables 2 and 3.

The compressor was designed to handle injection rate of 3.0 MMscf/day which was little higher than the calculated optimum lift gas injection rate of 2.7 MMscf/day. At a suction pressure of 115 psia and discharge pressure of 2015psia, the adiabatic compression power required to compress the volume of gas to be injected was estimated as 518 HP.

Prediction of discounted cash outflow and inflow over the projected field life was carried out using a spreadsheet. Parameters such as the Capital Expenditure (CAPEX), Operating Expenditure (OPEX), anticipated revenue, marginal field fiscal arrangements, oil price forecast and the desired discount rate were used to estimate NPV, Profitability Index (PI) and Internal Rate of Return (IRR). Due to uncertainties surrounding parameters such as recoveries, volatility of oil and gas prices, instability of fiscal regimes, and capital and operating costs, sensitivity and risk analyses were undertaken. For the shallow offshore location 7 km to existing facilities, some of the assumptions made include:

i. Price of crude oil was assumed as $43.01 (the average price between 2015 and 2016).

ii. Petroleum Profit Tax (PPT) was taken as 55% of the assessable profit on oil sales.

iii. For gas sales, Company Income Tax (CIT) of 30% was charged on assessable profit.

iv. Education tax was set at 2% of assessable profit

v. Tangible CAPEX was capitalized at 80% and depreciated over 5 years using straight-line depreciation technique at the rate of 20% and the fifth year at 19%. The OPEX was expensed 100%.

vi. The price of gas was taken as $3.0/Mscf

vii. Crude treatment and waste management was set at $2.00/barrel

viii. Discount rate was set at 10%

The probabilistic model was built using a software (@Risk Excel add-in) to analyze possible scenarios of in oil price, gas price, royalty, company income tax, petroleum profit tax and the cost of capital affect the output variables: Net Present Value (NPV), Internal Rate of Return (IRR), and Profitability index (PI).

ISSN: Print 2514-9253, Online 2514-9261

Table 1: Basic reservoir, completion and fluid data

Properties	Light Oil
Reservoir	
Porosity, fraction	0.3
Permeability, Md	1000
Vertical anisotropy (Kv/Kh), fraction	0.1
Initial oil saturation, fraction	0.8
Formation water salinity, ppm	20000
Reservoir temperature, ^oF	150
Productivity index , stb/d/psi	40
Water-cut, %	0
Initial reservoir pressure, psi	4000
Bubble point pressure, psi	3000
Abandonment pressure, psi	3600
Impurities (CO_2 , N_2, H_2S)	Negligible
Completion	
Completion type	Vertical
Top perforation, ftss	9800
Wellhead temperature, ^oF	100
Wellhead pressure, psi	200
Casing inner diameter (ID), in	8.42
Casing outer diameter (OD), in	8.92
Tubing ID, in	2.992
Tubing OD, in	3.5
Tubing relative roughness, in	0.05
Casing depth, ftss	10000
Fluid Properties	
Oil gravity, ^oAPI	32
Oil in-situ viscosity, Cp	0.7
Solution GOR (R_{si}), scf/stb	800
Gas gravity (air = 1)	0.78
Oil formation factor, rb/stb	1.3

ISSN: Print 2514-9253, Online 2514-9261

Table 2: Reservoir and aquifer Properties

Estimated OWC depth, ft	10000
Estimated GOC depth, ft	9860
Reference pressure, psi	4000
Initial pressure, psi	4000
Rock compressibility, psi^{-1}	3.25×10^{-6}
Aquifer thickness, ft	150
Aquifer Porosity, fraction	0.3
Aquifer Permeability, Md	1000

Table 3: Reservoir relative permeability

Properties	Value
Connate water saturation, Swc	0.2
Connate gas saturation, Sgc	0.05
Residual oil saturation to gas, Sorg	0.1
Critical water saturation, Swcr	0.05
Residual oil saturation to water, Sorw	0.1
Oil relative permeability, Kro	0.8
Water relative permeability, Krw	0.4
Gas relative permeability, Krg	0.9
Exponent for calculating Krw	3
Exponent for calculating Krow	3
Exponent for calculating Krg	3
Exponent for calculating Krog	2

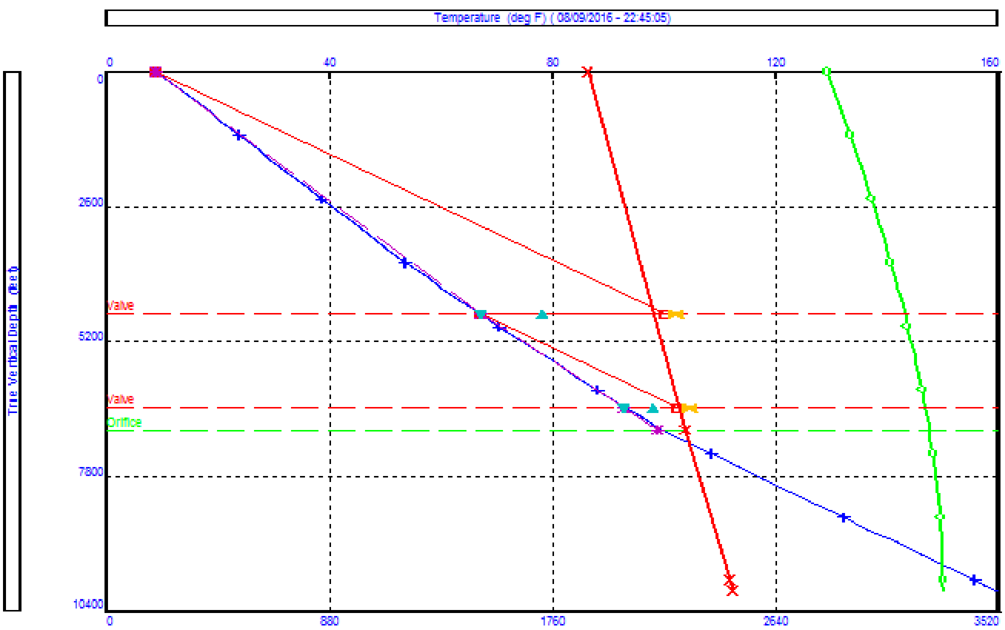

Figure 1: Design of the gas lift valves positions

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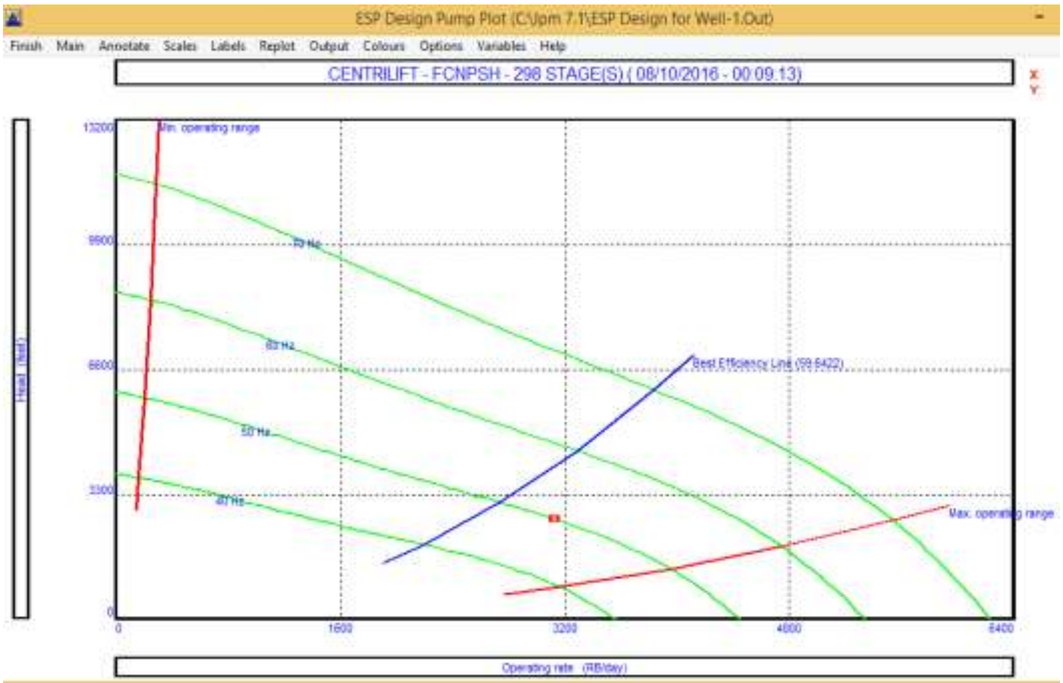

Figure 2: Pump curves for the Centrilift FCNPSH model

RESULTS AND DISCUSSION

Tables 1-3 give details of the reservoir and aquifer parameters, while Figures 1 and 2 indicate the design results for CGL and ESP respectively, using PROSPER. Tables 4-6 give the summary of the ultimate recovery and the profitability under natural flow, ESP and CGL. Under natural flow, 60.7% of the initial oil in place was recovered while 67.4% and 69.3% were recovered under gas lift and ESP respectively. This means that an increase of 6.7% will be recovered if Gas lift is installed after natural flow stops and 8.6% under ESP.

The results of the production profiles and sensitivity analyses are shown in Figures 3-7.

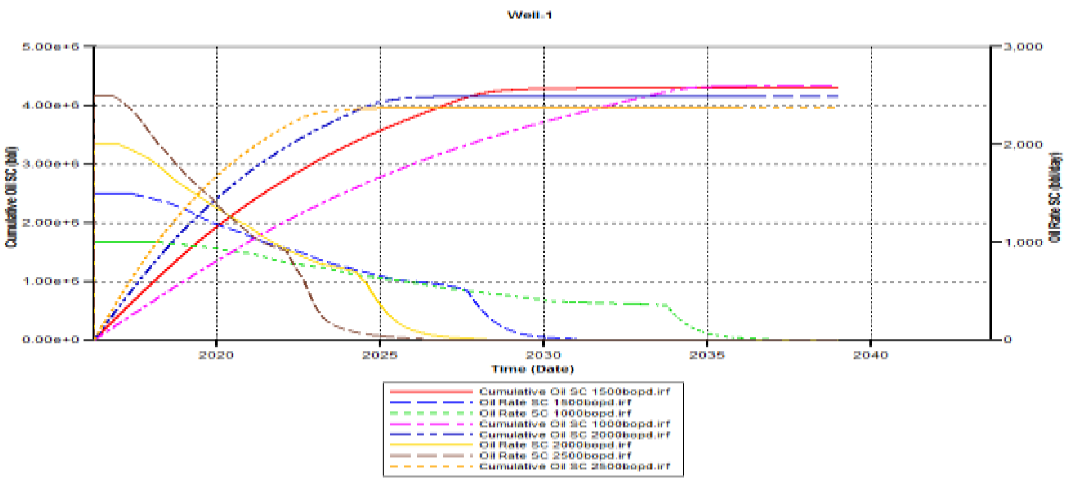

Figure 3: Plot of oil rate sensitivities

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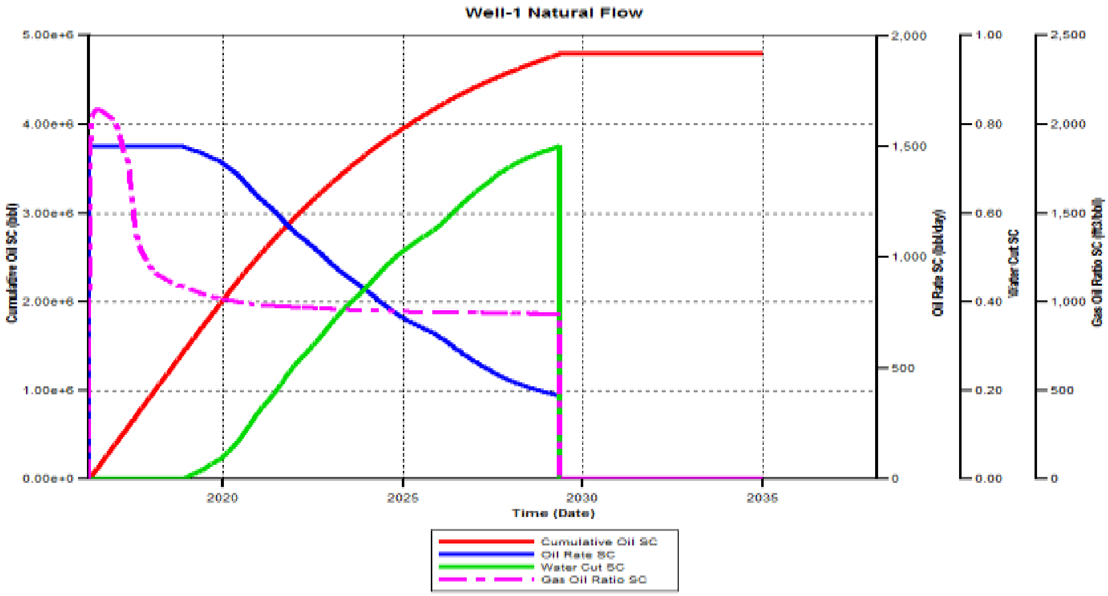

Figure 4: Well performance under Natural Flow

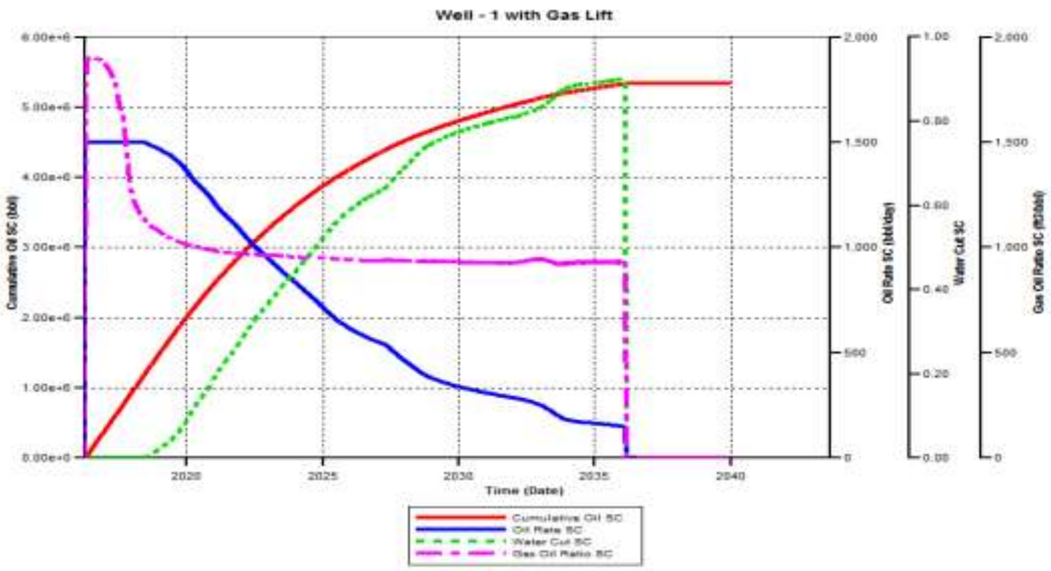

Figure 5: Well performance with Gas lift

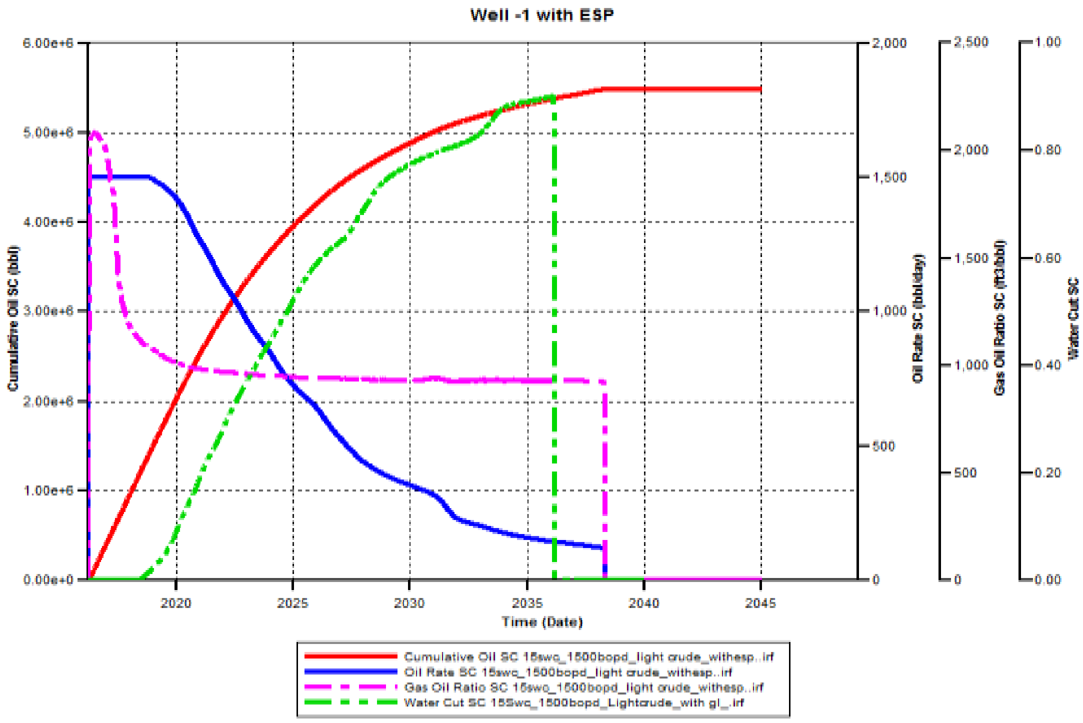

Figure 6: Well performance with ESP installed.

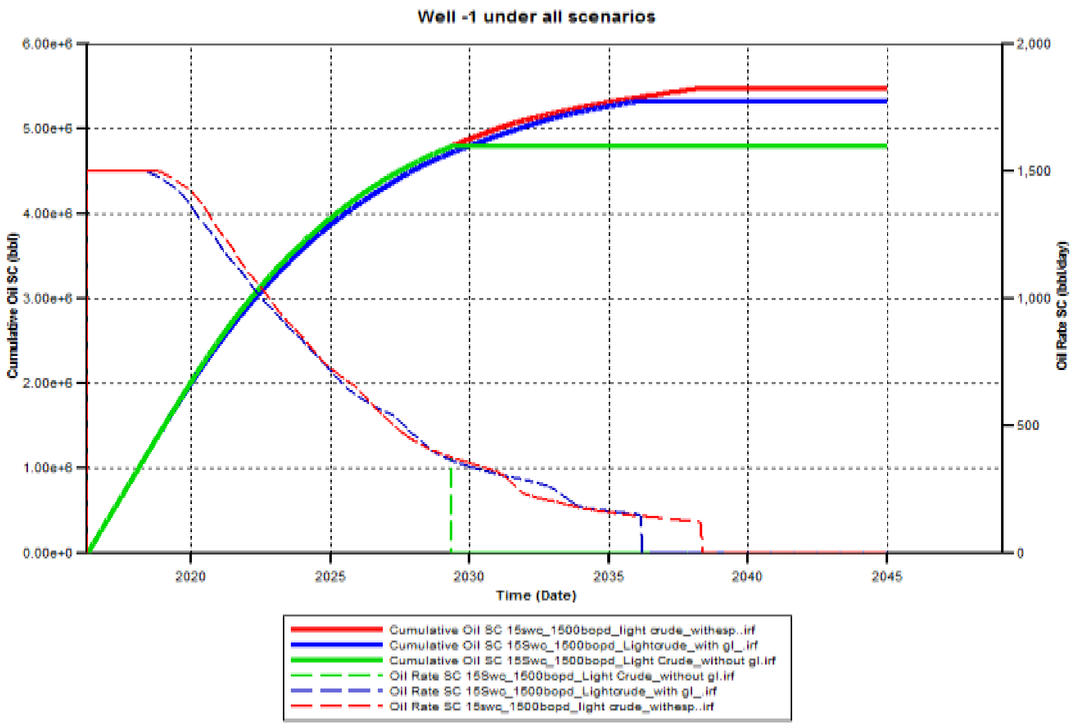

Figure 7: Well Production profiles for the three scenarios

ISSN: Print 2514-9253, Online 2514-9261

Table 4: Well Recovery under Natural flow and Artificial Lift

	OIL, MMSTB	GAS, TCF	WATER, MMSTB	R.F, fraction
Natural Flow	4.80	5.49	2.37	60.7
Gas Lift	5.33	5.99	5.54	67.4
ESP	5.48	6.13	6.57	69.3

Table 5: Profitability of marginal oil field under Early Life Artificial Lift Deployment

Indicator	Natural Flow	Gas Lift	ESP
NPV, $M	24.67	20.53	15.82
IRR, %	25.00	21.50	19.80
PI, fraction	1.74	1.56	1.45

The result of installing artificial lift methods at the end of natural flow to get incremental recovery from the field are presented in Table 6.

Table 6: Profitability of marginal oil field under Late Life Artificial Lift Deployment

Indicator	Gas Lift	ESP
NPV, $M	2.03	1.48
IRR, %	31.4	46%
PI, fraction	1.49	1.57

One of the objectives of the deterministic model is to determine the profitability of an investment from a glance without considering the uncertainties and risk involved. At a glance under prevailing fiscal terms, the use of the artificial lift methods was profitable at the prevailing oil price and fiscal terms. The IRR for the two artificial lift methods is greater than the discount factor of 10%. However, the decision to implement artificial lift from the beginning of the field's producing life is not as profitable as the natural flow, as the choice of natural flow gave higher NPV, IRR and PI than the artificial lift methods.

The choice of an installing artificial lift system at the end of the natural flow appears to be a good decision as the economic analysis of the CGL and ESP methods indicated positive NPV and PI greater than 1. The IRR is greater than the discount rate which means the decision will give a good return on the capital initially invested. However, ESP appears to be a better choice for optimizing production in the field than continuous gas lift method. Though continuous GL method has a higher NPV than the ESP method, NPV alone is inadequate in making economic decision due to its inability to indicate investment efficiency. The ESP appears a better choice because of the higher IRR and Profitability Index. The CGL system seems to be inefficient in producing small fields having a single well, but should give improved economic returns when there are multiple wells.

The impact of oil price on profitability indicators is represented by Figures 8 and 9. It will be observed that at oil prices below $35, the NPV becomes negative and the IRR below the

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discount rate. The investment becomes unprofitable. However, as the oil price increases, the NPV and IRR increased. It can be deduced from this analysis that the price of crude oil is a major driver for the use of artificial lift for production optimization of the marginal field.

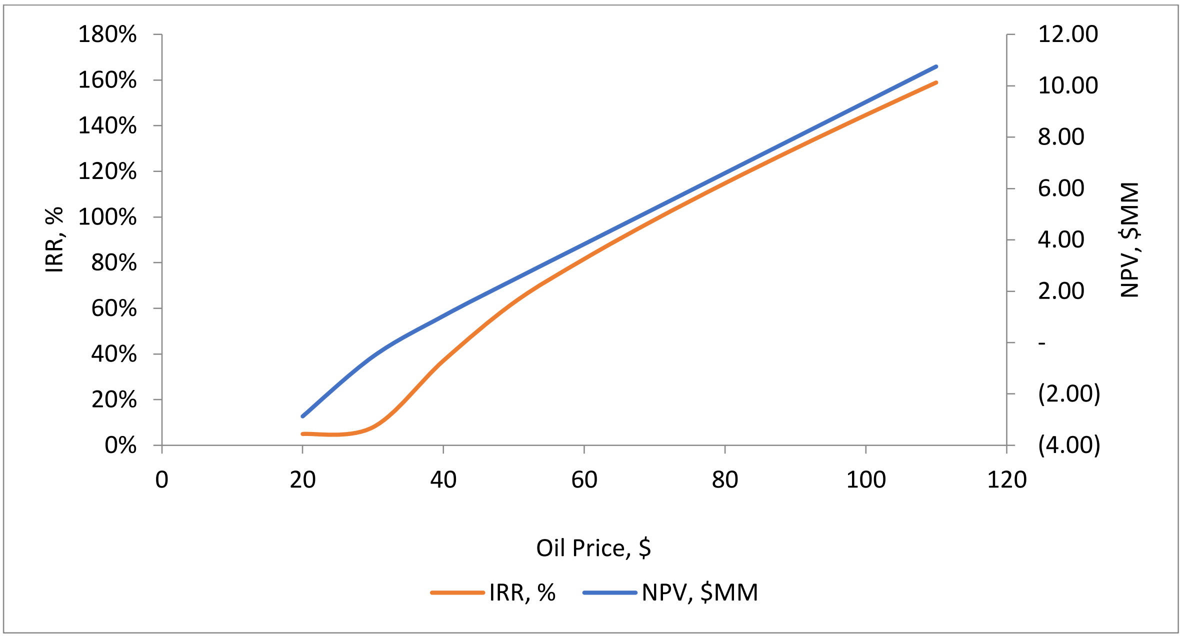

Figure 8: Effect of oil price on NPV and IRR of ESP method

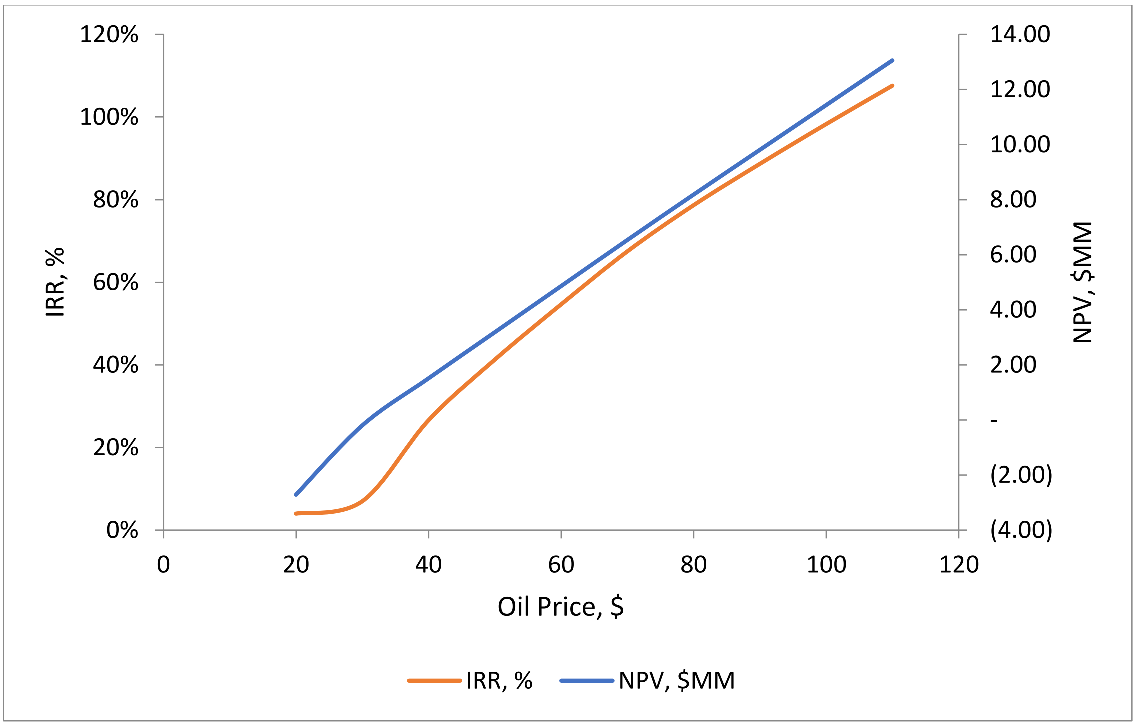

Figure 9: Effect of oil price on NPV and IRR of Continuous Gas Lift method

The Petroleum Profit Tax (PPT) component of the fiscal terms is another factor that affects the profitability of marginal fields in Niger Delta. It is obvious from Figures 10 and 11 that there

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is an inverse relationship between the tax rate and the profitability indicators. The decision to use artificial lift for production optimization becomes profitable as the PPT rate reduces while at higher tax rates, the investment becomes unprofitable.

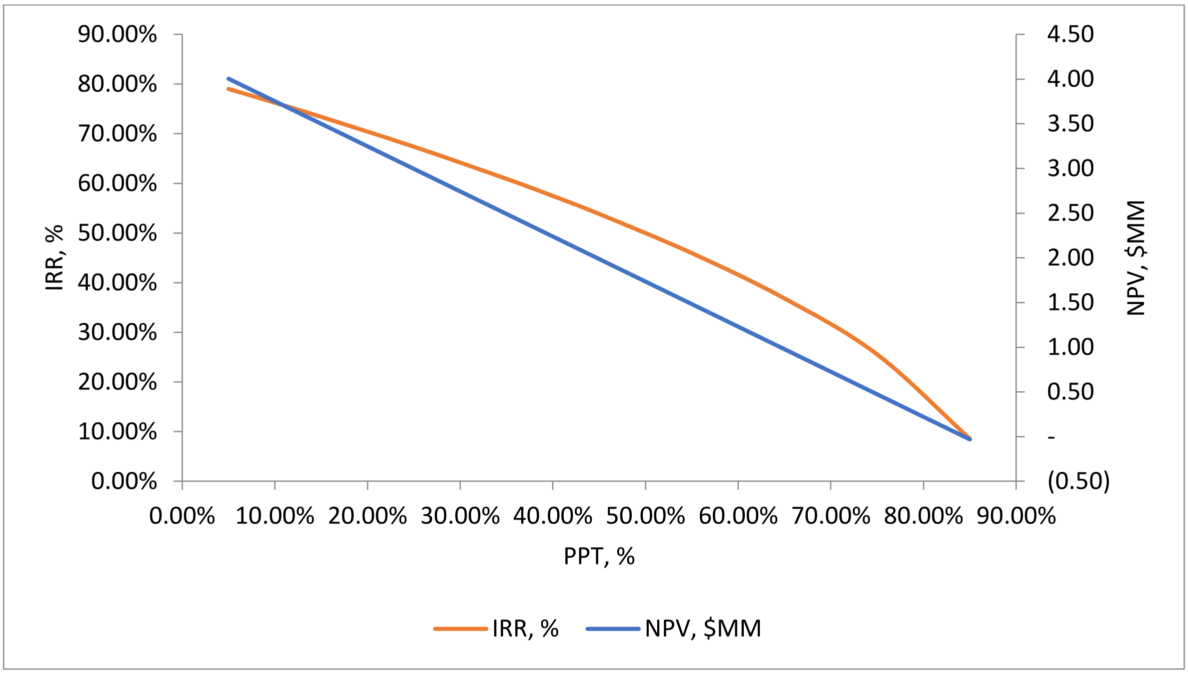


Figure 10: Effect of fiscal terms on NPV and IRR of ESP method

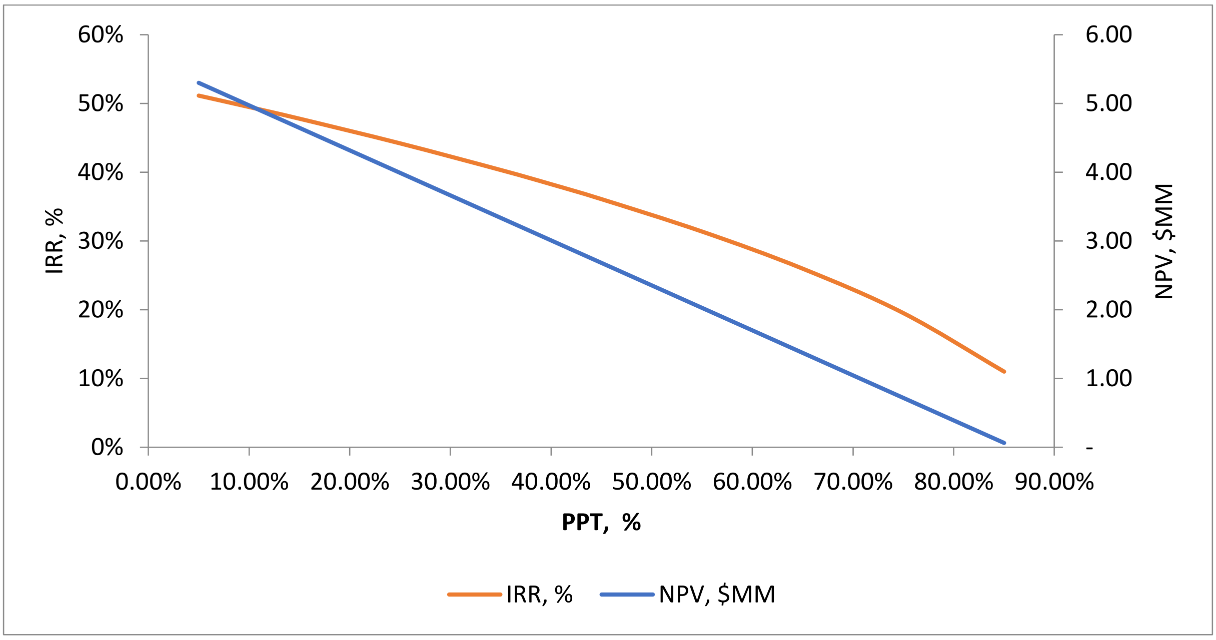
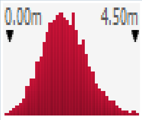
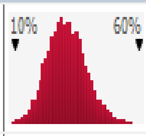
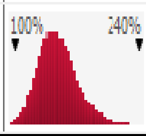


Figure 11: Effect of fiscal terms on NPV and IRR of Continuous Gas Lift method

The effect of risk and uncertainties associated with the input and the output variables used for the deterministic economic model was analyzed. The best and worst-case scenario for the each of the variables were presented.

ISSN: Print 2514-9253, Online 2514-9261

Table 7: Profitability distribution functions imposed on the various variables

Name	Worksheet	Cell	Graph	Min	Mean	Max	5%	95%
NPV / GL	GL Cash Flow model	AC15		$68,922.40	$2,040,499.00	$4,492,051.00	$908,974.50	$3,253,995.00
IRR / GL	GL Cash Flow model	AC16		11.0629%	31.4884%	56.0504%	20.4816%	43.3524%
PI / GL	GL Cash Flow model	AC18		1.016751	1.503146	2.260634	1.213493	1.838684

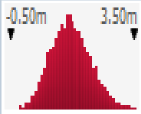
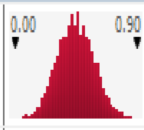
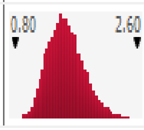
Name	Worksheet	Cell	Graph	Min	Mean	Max	5%	95%
NPV / ESP	ESP Cash Flow model	AC15		-$66,651.24	$1,478,624.00	$3,447,729.00	$568,847.60	$2,471,724.00
IRR / ESP	ESP Cash Flow model	AC16		8.2642%	45.6239%	84.3770%	25.9233%	65.3173%
PI / ESP	ESP Cash Flow model	AC18		0.9772632	1.570596	2.443573	1.21142	1.976176

Table 7 gives the 90% certainty levels of the variables used for the probabilistic analyses. For both artificial lift methods, the NPV for both scenarios are positive which means that use of the lift methods were profitable. The Table also indicates a high return on investment. An average IRR of 31.4% and 45.6% for gas lift scenario and ESP scenario is higher than the discount rate of 10% used for this analysis, this investment is worthwhile as it can conveniently pay back borrowed funds and gives a reasonable margin. There is 90% confidence that IRR will vary from 11.1% to 56.1% for continuous gas lift and 8.3% to 84.4% for ESP scenario. All these indicators show that optimizing marginal oil field with artificial lift is a profitable investment.

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CONCLUSION

This study used data obtained from a marginal oil field in the Niger Delta to evaluate the profitability of using electric submersible pumps and continuous gas lift. It was observed that the artificial lift methods would optimize production as their application gave incremental oil recovery when applied either early or later in the producing life of a marginal oil field. The result of the economic evaluation however indicated that the artificial lift methods were better applied at later life when natural flow had ended. The ESP proved a better choice in optimizing production from the marginal field while continuous gas lift was not efficient for producing the small field where a single well is involved because of the high initial capital investment. Risk and sensitivity analyses show that the profitability of using ESP and continuous gas lift to optimize recovery from the marginal field was greatly affected by oil price, fiscal regime and initial capital expenditure and operating expenditure of the selected lift methods.

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ISSN: Print 2514-9253, Online 2514-9261

APPENDIX

Table 1C: Capital cost of items and prices of Gas Lift.

Item	Cost, $well
Gas lift valves	20,000
Compressor	759,000
Gas lift pipeline	2,800,000
Wireline Service	150,000
Miscellaneous	745,800
Total CAPEX	4,474,800

Table 2C: Capital cost items and prices of ESP

Item	Cost, $well
Rig Personnel, mobilization and security	1,500,000
Cable	70,000
Cable Protector	40,000
Pump	150,000
Protector	745,800
Rotary Gas Separator	4,474,800
Motor	60,000
Transformer	40,000
Variable Speed Drive	80,000
Power Generator	250,000
Miscellaneous	434,000
Total CAPEX	2,604,000

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