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Comparison of Three Artificial Lift Operations in the Niger Delta

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Authors' contributions

This work was carried out in collaboration between both authors. Author CIN designed the study, wrote the first draft of the manuscript and designed the reservoir modeling and simulation processes. Author JUA checked the whole manuscript and analyzed the economic aspect of the design and the oil price. Both authors read and approved the final manuscript.

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ABSTRACT

More than 70% of oil-producing wells require some form of artificial lift to increase the flow of fluids from subsurface to the surface when a reservoir no longer has sufficient energy to produce at economic rates. This situation has been observed in the Niger Delta oil wells over the past years and has caused the abandonment of reservoirs with a significant volume of hydrocarbon. Data from two oil wells that could not flow naturally to the surface have been obtained from an oil company operating in the Niger Delta. The arm of this study is to optimize the production of two oil wells using an artificial lift system. To increase production and extend the life of these wells, artificial lift projects were considered. This was done with the aid of Integrated Production Modelling (IPM) tool in Petroleum Expert suite. Two wells were simulated using the obtained data, and their production performances were evaluated. The well's production outputs were optimized using artificial lift systems, that is electric submersible pump (ESP), hydraulic pump (HP), and gas lift (GL). The results obtained showed that the ESP wells have the highest oil production rate compared to GL and HP respectively. An economic analysis was carried out using Net Present Value (NPV), Profitability Index (PI) and Internal Rate of Return (IRR). In terms of economic comparison, ESP is the most viable project

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with the highest NPV, PI and IRR Hence, the ESP technology proved to be the best technology for sustaining a high production rate, increasing revenue and proved to be economically viable in Niger Delta oil fields.

Keywords: Artificial lift; gas lift; hydraulic pump; electric submersible pump; economic indicator.

1. BACKGROUND OF THE STUDY

Hydrocarbons will normally flow to the surface under natural flow when the discovery well is completed in a virgin reservoir. The fluid production resulting from reservoir development will normally lead to a reduction in the reservoir pressure, an increase in the fraction of water being produced together with a corresponding decrease in the produced gas fraction. All these factors reduce or may even stop the flow of fluids from the well. The remedy is to include within the well completion some form of artificial lift. An artificial lift system (gas lift or pumping system) must supplement the energy supplied by the reservoir in order to produce fluid at the surface. The precise amount of energy needed is represented by the vertical separation between the two curves. Artificial lift systems are designed to help natural reservoir energy to flow formation fluids to the surface at targeted rates [1]. They are employed when reservoirs do not have enough energy to naturally produce oil or gas to the surface or at the desired economic rates. Most often associated with mature fields, this energy shortfall typically occurs when the reservoir pressure has been depleted through production.

Pumping solutions, such as artificial lift methods, have been used in the oil industry for more than 100 years. The selection and application of each of these options depends on its advantages and particularities related to the production scenarios considered. Currently, the most often applied artificial lift technologies are sucker rod pumping (SRP), hydraulic jet pumping (HJP), progressive cavity pumping (PCP), ESP, hydraulic submersible pumping, and hydraulic piston pumping (HPP) [2-3] stated challenges abound for operators attempting to deploy artificial lift systems in unconventional applications. As always, operators set a variety of challenging business and operational goals for themselves: minimize capital and operational expenditures; maximize drawdown over the well's life; and minimize downtime, failure frequency, and intervention frequency. (ESP) is one of the most efficient artificial lift methods used in the oil industry for lifting moderate to high volume of fluids from wellbores to surface, proper sizing and selecting of the ESP system mainly depends on accurate data especially that pertaining to the well's capacity, if the given data is not accurate then the design will usually be marginal and lead to premature failure [4]. It accounts for over 60% of artificial lift methods used globally and contributes significantly to the CAPEX and OPEX of a project. They tend to be the least reliable component in the system with an average lifespan of 2 years [5]. It is also a key artificial-lift technology to the petroleum industry. Worldwide installations of ESPs are in the range of 130,000 units, contributing to approximately 60% of the total worldwide oil production [6]. Key to achieving the production gains was candidate selection and well testing to confirm the well productivity and aquifer pressure support. This process also mitigated risk by selecting wells from a reservoir sector with a historical low incidence of asphaltenes and GORs, which have not spiked substantially above solution GOR. Once the ESPs were installed, the production gains were achieved by correctly managing drawdown through real-time surveillance, which was also used to manage the stress on the ESP and avoid infant mortality. Longer term run lives were achieved by selecting the correct ESP materials and completion architecture for the well conditions [7]. Croce and Pereyra [8] evaluated the impact of the effective viscosity of the emulsions on the head and flow rate delivered by the ESP. Walter et al., 2020, developed a troubleshooting manual that could be used for any engineer to identify likely conditions that could be affecting negatively ESP performance and to implement solutions to minimize failure or damage beyond repair in ESP equipment. Gas lift as a method of artificial lift has been used in the industry for over 100 years, there were many advances in gas lift system design during the development of the systems from the early rudimentary designs [9]. But optimizing gas lift systems with existing technology is typically time consuming, costly, and risky. Frequent well interventions are required with associated lost and/or deferred production.

2. ELECTRICAL SUBMERSIBLE PUMP

ESP systems consist of both surface components (housed in the production facility, for example, an oil platform) and sub-surface components (found in the well hole). Surface components include the motor controller (often a variable speed controller), surface cables and transformers. Subsurface components typically include the pump, motor, seal and cables. The pump itself is a multi-stage unit with the number of stages being determined by the operating requirements.

2.1 Hydraulic Pump

Hydraulic pumps are used in hydraulic drive systems and can be hydrostatic or hydrodynamic. A hydraulic pump is a mechanical source of power that converts mechanical power into hydraulic energy (hydrostatic energy i.e. flow, pressure). It generates flow with enough power to overcome pressure induced by the load at the pump outlet. When a hydraulic pump operates, it creates a vacuum at the pump inlet, which forces liquid from the reservoir into the inlet line to the pump and by mechanical action delivers this liquid to the pump outlet and forces it into the hydraulic system. Hydrostatic pumps are positive displacement pumps while hydrodynamic pumps can be fixed displacement pumps, in which the displacement (flow through the pump per rotation of the pump) cannot be adjusted, or variable displacement pumps, which have a more complicated construction that allows the displacement to be adjusted. Although, hydrodynamic pumps are more frequent in day-to-day life.

2.2 Gas Lift

Gas lift systems aid or increase production by injecting high-pressure gas from the casing annulus into fluids that have entered the production tubing from the formation. The function of this injected gas is to reduce the density and thus, reducing the hydrostatic pressure of the fluid, thereby allowing in in situ reservoir pressure to lift the lightened liquids. The technical applicability and economic viability of gas lift installations are determined by two factors: availability of gas and compression costs. In the majority of gas lift wells, nearby wells produce enough gas to supply the system, and after the fluids have been lifted to the surface, the gas can be separated from the liquids and returned to the casing annulus to maintain required gas volume and pressure. When circumstances permit, the industry also uses natural, or auto, gas lift systems, which is highly cost effective because it eliminates the need for compressors, pipelines or a separate source of natural gas.

Gas lift system is first designed by calculating the production potential of each well in the network. Then based on available gas pressure and volume, each well, its optimum production and gas lift allocation is designed. An ideal gas lift system is one in which gas is injected into the fluid column at a continuous rate and at a constant pressure. This process ensures that a stable liquid flow rate from reservoir and is possible only in fields in which sufficient volumes of high-pressure gas are available and liquids can flow easily through the formation into the wellbore. Engineers must also construct wells to accommodate the type of injection system to be used. Gas may be injected into the fluid column through an open system that has no seal between the tubing and the casing annulus or uses a standing valve in the tubing to isolate the casing annulus from the production tubing. However, the most common gas lift configuration includes a packer and gas lift valves.

Designing a gas lift system that optimizes production is a complex challenge. Engineers must account for the interaction system; the potential, constrains and needs of each well must be considered individually along with those of the network as a whole. Flowline and downhole tubular sizes lengths, processing equipment, gas and compressor availability, fluid composition and other factors impact gas lift efficiency and production Gas lift is a recovery process that involves the use of gases, produced from oil or purchased. There are two types of gas lift, namely, intermittent gas lift and continuous gas lift. The gas lift process involves the injection of high-pressure gas at the bottom of the production tubing of an oil well. In other words, gas lift involves injecting high-pressured gas from the surface into the producing fluid column through one or more subsurface valves set at predetermined depths. This helps to improve recovery by reducing the bottom-hole pressure at which wells become uneconomic, resulting in being abandoned. The gas, mixed with the oil, diminishes the weight of the fluid column thereby reducing the downhole pressure. A low downhole pressure induces a flux of fluids from the reservoir to the well. The produced fluid is composed of oil, gas and water.

3. METHODOLOGY

This research used commercial software in the Integrated Production Modelling (IPM) suite-

Production and Systems Performance Analysis (PROSPER), Material Balance (MBAL) and General Allocation Package (GAP), [10]. Reliable production data of two oil wells were obtained from an oil company operating in the Niger Delta Table 1. The two wells were simulated and the production outputs were optimized using artificial lift systems ESP, HP and GL. MBAL was used for reservoir modeling and description. PROSPER was used to design the artificial lift systems for the wells. GAP was used to integrate the PROSPER and MBAL models for production optimization Fig 1. The flow charts for the operation of the software and the steps taken to achieve the aim and objectives of this project are summaries in Figs 2 to 4.

After optimizing the wells' outputs, an economic analyze was carried out to assess the viability of the project. The economic indicators employed to assess the profitability of this project are Net Present Value (NPV), Profitability Index (PI) and Internal Rate of Return (IRR).

3.1 Design of Artificial lift System

The first step when modelling a new well in IPM will be to fill out a system summary. The Black Oil model with oil and water option will be used to describe the fluid flow in the reservoir model. It is also here that the choice of artificial lift or natural flowing method was made. The next step was to fill in the PVT data. The basic

Table 1. Collected fluid properties (FP) of two oil wells from field X

well 1		**well 2**	
GOR	**1000 scf/STB**	**GOR**	**1200 scf/STB**
API	40	API	40
Gas Gravity	0.8	Gas Gravity	0.8
Mole % of H_2S	0	Mole % of H_2S	0
Mole % of CO_2	0	Mole % of CO_2	0
Mole % of N_2	0	Mole % of N_2	0
Oil Density	41 Ib/ft3	Oil Density	46 Ib/ft3
Oil FVF	1.3 RB/STB	Oil FVF	1.3 RB/STB
Oil Viscosity	0.6 Cp	Oil Viscosity	0.6 Cp
Oil Compress	1/psi	Oil Compress	1/psi
Gas Density	0.04 Ib/ft3	Gas Density	0.8 Ib/ft3
Gas Viscosity	0.3 Cp	Gas Viscosity	0.2 Cp
Gas FVF	0.006 ft3/scf	Gas FVF	0.008 ft3/scf
Water Density	65 Ib/ft3	Water Density	64 Ib/ft3
Water Viscosity	0.4 Cp	Water Viscosity	0.4 Cp
Water FVF	1.0 RB/STB	Water FVF	1.0 RB/STB
Water Salinity	80000 ppm	Water Salinity	82000.9 ppm
Overall Heat	3 BTU/H/FT2/F	Overall Heat	3BTU/H/FT2/F
Cp Oil	0.5 BTU/Ib/F	Cp Oil	0.5 BTU/Ib/F
CP Gas	0.5 BTU/Ib/F	Cp Gas	0.5 BTU/Ib/F
Reservoir Pressure	4500 psi	Reservoir Pressure	5000 psi
Reservoir Temperature	183 degF	Reservoir Temperature	205degF
Water cut	50%	Water cut	40%
Reservoir Permeability	500 md	Reservoir Permeability	600 md
Reservoir Thickness	200 ft	Reservoir Thickness	200 ft
Drainage Area	250 acres	Drainage Area	250 acres
Dietz Shape Factor	10	Dietz Shape Factor	10
Wellbore Radius	0.5 ft	Wellbore Radius	0.5 ft
Skin	0	Skin	0
Porosity	0.27 Fraction	Porosity	0.3 Fraction
Connate Water Sat	0.2 Fraction	Connate Water Sat	0.2 Fraction
Original Oil in Place	2000 MMSTB	Original Oil in Place	2000 MMSTB
Initial Gas Cap	0	Initial Gas Cap	0

Source: Field data (2021)

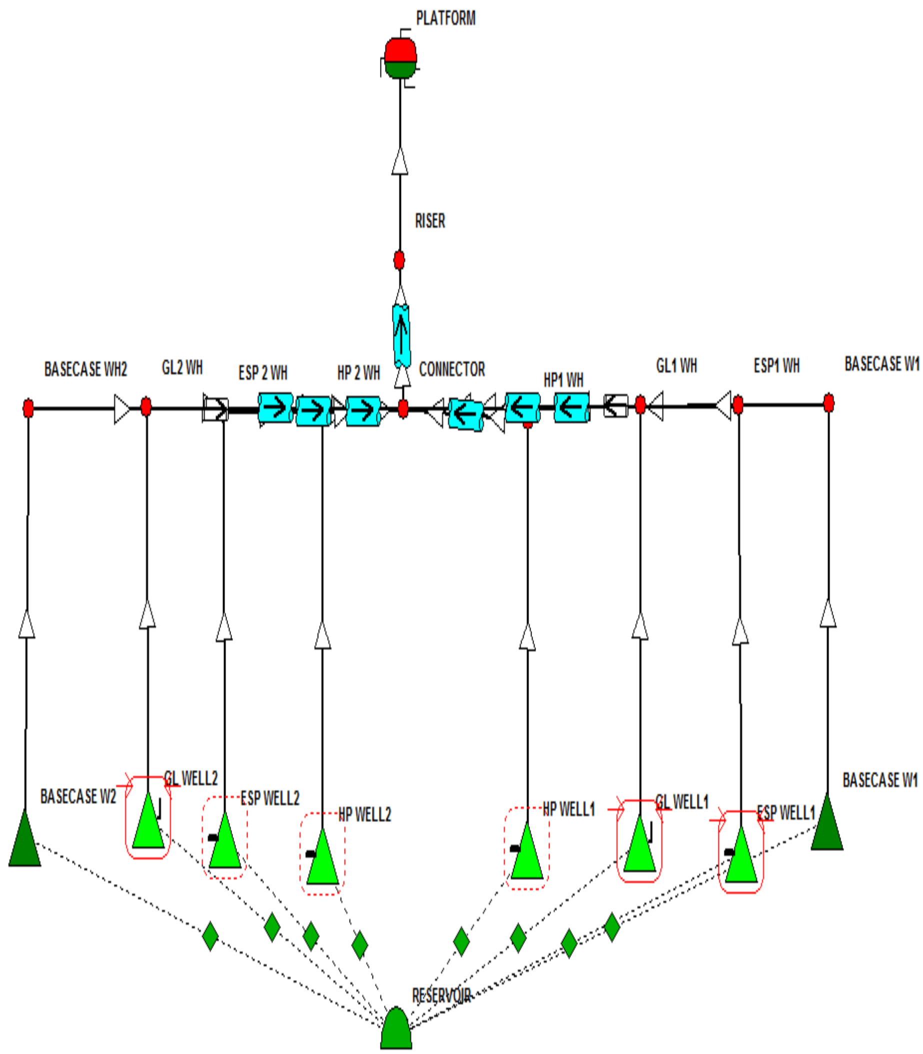

Fig. 1. Typical wells model with GAP software

reservoir parameters such as initial reservoir pressure (P_i), bubble point pressure (P_b), reservoir temperature (T_R), gas–oil ratio (GOR), oil formation volume factor (FVF), etc., were inputted into the PROSPER software (PVT Data Simulator) to history match the reservoir`s PVT data.

3.2 ESP and HP Design

When modelling ESP and HP well with PROSPER software, a number of parameters have to be entered into the system. The ESP input data screen is divided into six windows. The first window is called the options summary where the choice of artificial lift was made. The second window is called the PVT data window where the PVT data were entered. The third window is called the Inflow Performance Relationship (IPR) data window where the IPR data were entered. The fourth is the equipment data were entered and the artificial lift (ESP, HP or GL) was designed and simulated. The fifth window is the analysis summary and also called the results window. The six window is the IPM licence window. Figs 5 and 6 represent the performance curves of ESP and HP.

3.4 Gas Lift Design

When modelling a gas lifted well, a number of parameters have to be entered into the system. The gas available for lifting has the following characteristics Tables 2and 3). The operating injection pressure was set to 1500 psi. Desired differential pressure (dP) across valves, 200 psi, was entered to ensure well and gas injection system stability. Minimum spacing between valves was set to 250 feet. Sea water was assumed as the load fluid before gas lift start, which result in a static gradient of 0.46 psi/ft. Also, maximum injection depth for the well was set at 7500 feet. The most used valve type is the casing sensitive, which was also chosen here. Valve settings was selected to "Pvc = Gas Pressure". Then PROSPER sets valve dome pressure to balance casing pressure at depth of 7500 feet.

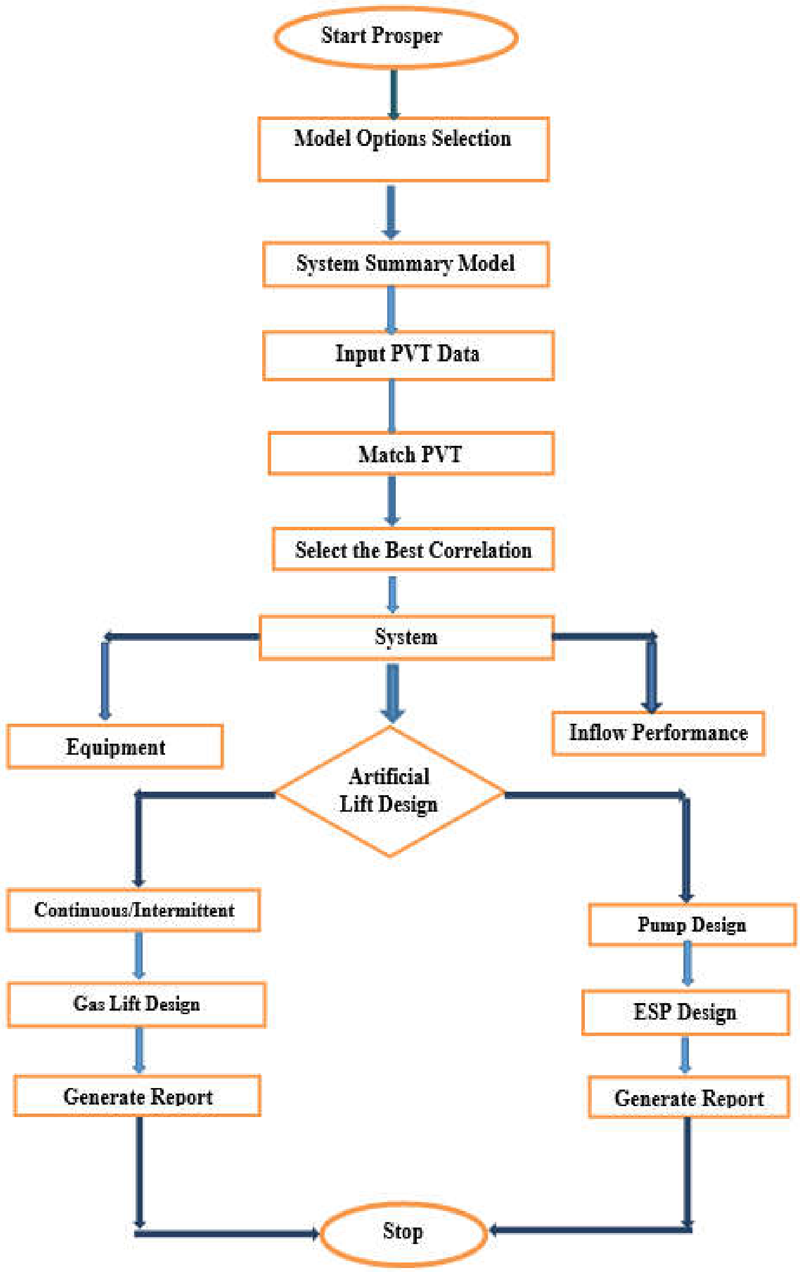

Fig. 2. Workflow for the operation of PROSPER software

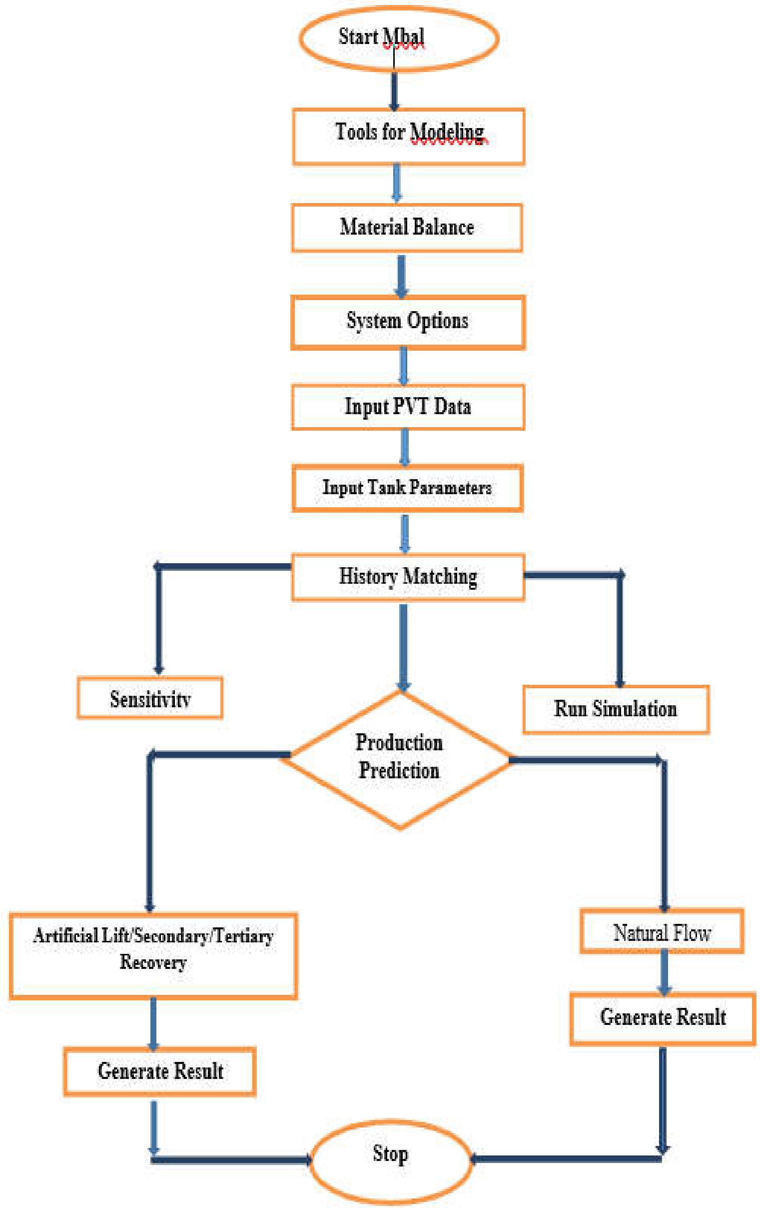

Fig. 3. Workflow for the operation of MBAL software

3.5 Economic Analysis

In making a decision whether to invest in a project, the incremental cost to complete the project should be compared with the future net revenue to be received from the project. And if the expected net revenue is greater than the expected investment cost, the project should be completed but if not, the project should be abandoned. Therefore, in making a final decision on installing ESP, HP or GL systems on these wells, a thorough economic analysis was carried out. It is the profitability of a project that has to be the final decision criteria. However, the initial costs of the scenarios were analyzed and have given a good indication of the project magnitude. Table 4 shows the capital cost e.g. the cost until end of installation of each project. This involves cost of procurement, construction, engineering, maintenance, administration and operational cost during installation.

4. RESULTS AND DISCUSSION

4.1 Results

4.1.1 Results of oil production forecast for well 1 with base-case (no lift), ESP, GL, and HP

Fig 7. presents base-case (no lift), ESP, GL, and HP Performances of Well1 in terms of Oil Production (WPR) versus time. The base-case indicates (in blue) that there was a steady oil production through the period of 6 years before gradually decline towards the end of production. For ESP (in yellow), a steady oil rate was observed throughout the period of production forecast (9 years) with a slight decline (about 3% decline) at the end of production. For GL (in black), a steady oil production rate was observed throughout the first 6 years of production with rapid decline (about 33% decline) at the end of the last 3 years of production. Also, for HP (in red), there was a steady decline (about 39% decline) in oil production rate throughout the period of production.

4.1.2 Simulation results of gas production for well 1

Fig. 8. presents the base-case, ESP, GL, and HP Performances of Well1 in terms of Gas Production (WPR) versus time. For HP, base-case, GL, and ESP, Gas production was on the increase throughout the period of production.

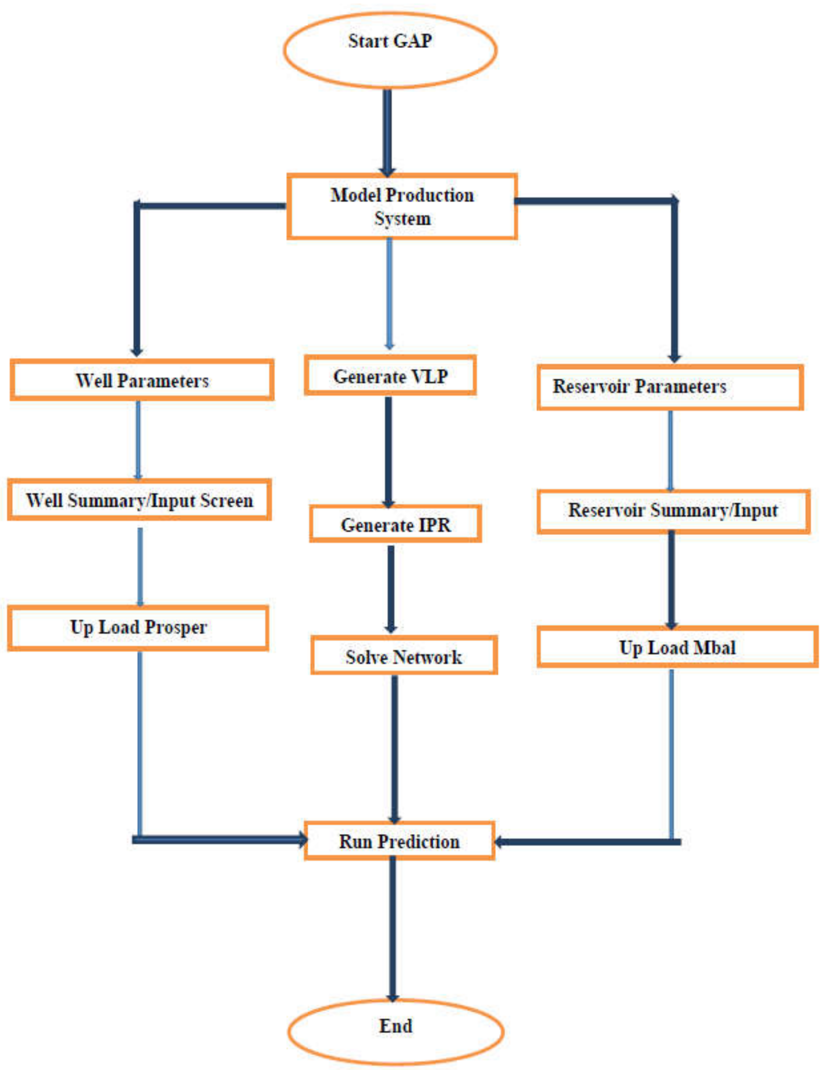

Fig. 4. Workflow for the operation of GAP software

Table 2. Gas lift design Parameters from field X

Gas lift parameters	Values
Gas Lift Gas Gravity	0.8
Maximum Liquid Rate	15000 stb/day
Maximum Gas Available	10 MMscf/d
Maximum Gas while Unloading	10 MMscf/d
Flowing Top Node Pressure	200 psig
Unloading Top Node Pressure	200 psig
Operating Injection Pressure	1500 psig
Kick Off Injection Pressure	1500 psig
Desired dP across Valve	200 psi
Maximum Depth of Injection	7500 ft
Water Cut	80%
Minimum Valve Spacing	250 ft
Static Gradient of Load Fluid	0.5
Minimum Transfer dP	25%
Maximum Port Size	32 (set by valve series selection)
Safety for Closure of Last Unloading Valve	0 psig
Rating Percentage for Valves/Orifice	100%

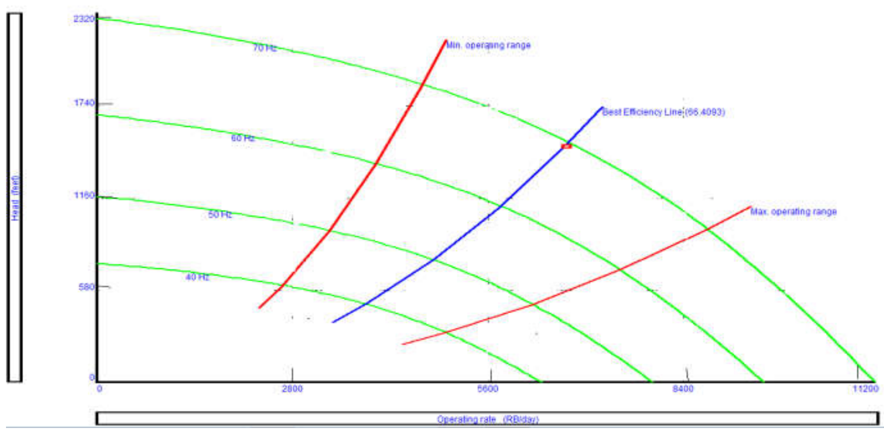

Fig. 5. ESP performance curve

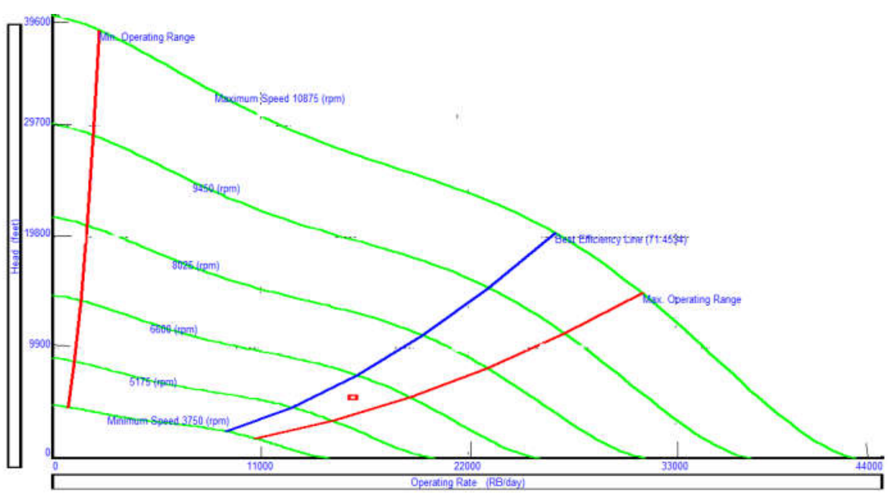

Fig. 6. HP performance curve

Table 3. Collected downhole equipment from field X

MD(feet)	TVD(feet)	Xmas Tree	MD (feet) inches	Tubing (ID) inches	Roughness Inches	Tubing (OD) inches	Casing (ID) Inches
0	0		59.4	1	0.0006	0	0
463.3	463.3	Tubing	689	4	0.0006	4.5	8.7
2399.9	2368.4	SSSV	0	2.1	0.0006	0	0
3450.1	3256.6	Restriction	7660.8	4	0.0006	4.5	8.7
4649.9	4100.1	Tubing	0	2.3	0.0006	0	0
5200.1	4467.5	Casing	7677.2	4	0.0006	4.5	8.7
6899.9	5673.9	Casing	7860.9	0	0.0006	0	8.7
7450.1	6076.7	Casing	8169.3	0	0.0006	0	6.2
8687.7	7280.2	Casing	8687.7	0	0.0006	0	4

Table 4. Estimated cost for ESP, HP and GL

For Nine Years	HP	GL	ESP
Item	Cost ($1,000,000)	Cost ($1,000,000)	Cost ($1,000,000)
Downhole pump/Installation	5	0	20
Equipment	5.1	10	15
Purchased Gas	0	15	0
Operating/Maintenance	15	3.2	25.5
Sum	25.1	28.2	60.5

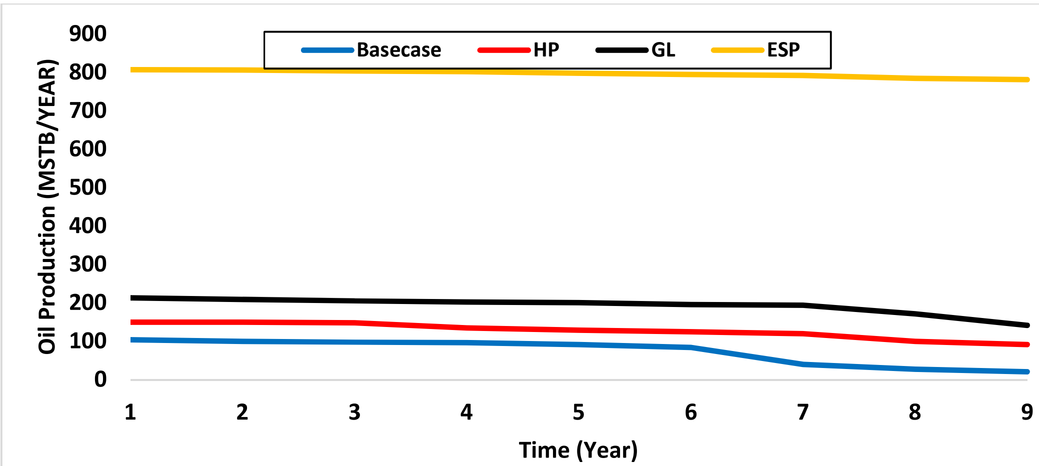

Fig. 7. Presents the base-case, ESP, GL, and HP Performances of Well1 in terms of Oil Production (WPR) versus time

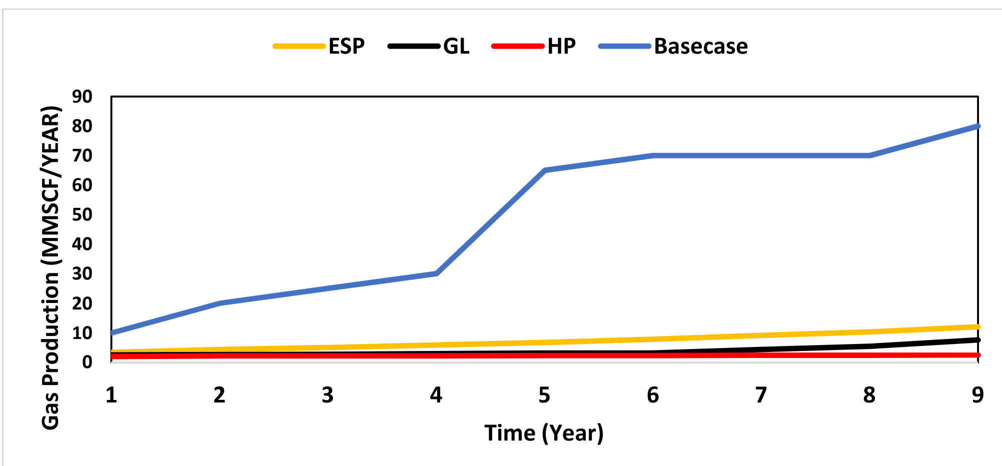

Fig. 8. Presents the base-case, ESP, GL, and HP performances of well1 in terms of gas production rate (GPR) versus time

4.1.3 Simulation results of water production for well 1

Fig 9. presents the base-case, ESP, GL, and HP Performances of Well1 in terms of Water Production (WPR) versus time. For base-case production, it was observed that Water breakthrough occurred after 2 years and increases throughout the period of production. For ESP, GL and HP productions, Water breakthrough also occurred after 2 years and increased till the end of production.

4.1.4 Simulation results of oil production for well 2

Fig. 10: presents the base-case, ESP, GL, and HP Performances of Well2 in terms of Oil Production (OPR) versus time.For base-case well2, the Figure indicates that there was a steady oil production throughout the period of production. For ESP, a steady oil rate was observed throughout the first 6 years of production with a slight decline (about 21% decline) at the end of production. For GL, indicates that a gradual decline (about 23% decline) in oil production was observed with increasing gas production throughout the period of production. Also, for HP, indicates that a gradual decline (about 44% decline) in oil production was observed with increasing gas production throughout the period of production.

4.1.5 Simulation results of gas production for well 2

Fig. 11. presents the base-case, ESP, GL, and HP Performances of Well2 in terms of Gas Production (WPR) versus time.For HP, GL, and ESP,Gas production was gradually on the increase throughout the period of production with a tremendous increase on base-case scenario.

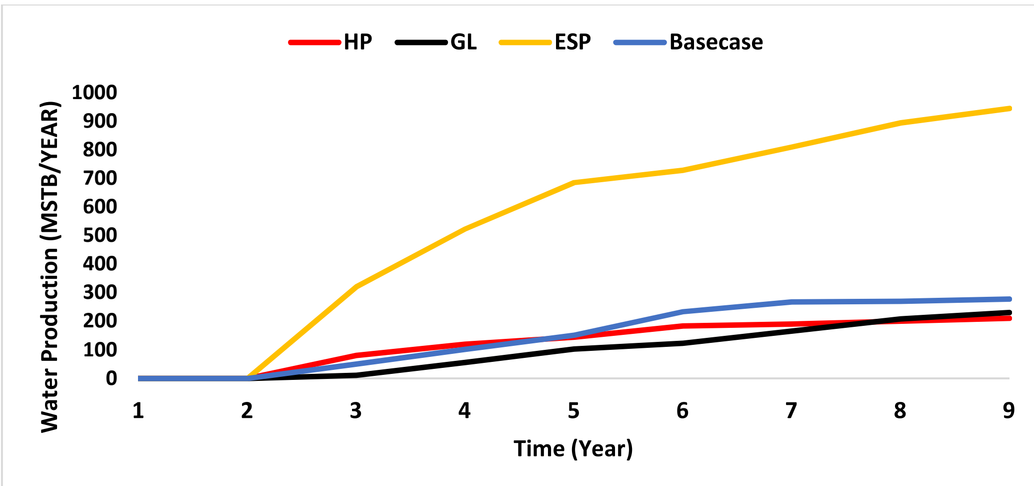

Fig. 9. Presents the base-case, ESP, GL, and HP performances of well1 in terms of water production rate (WPR) versus time

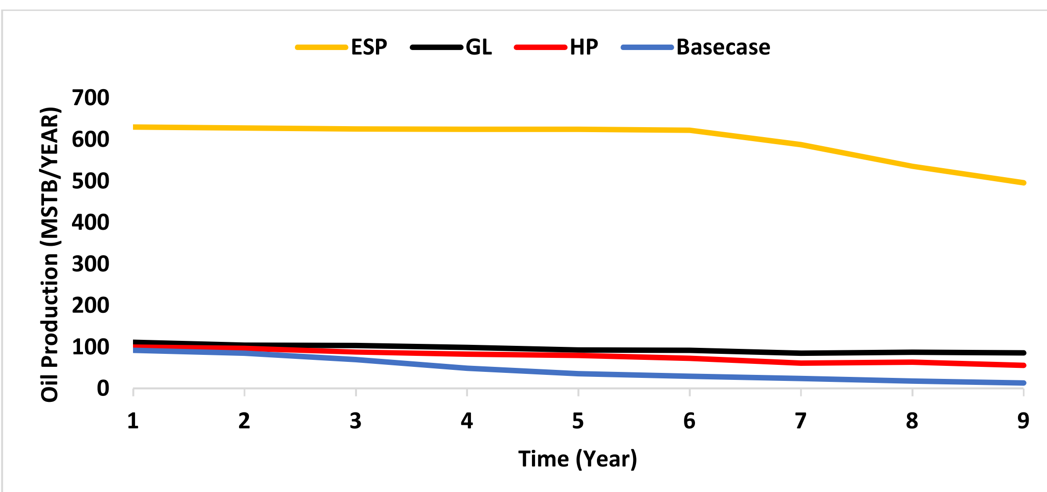

Fig. 10. presents the base-case, ESP, GL, and HP Performances of Well2 in terms of oil production rate versus time

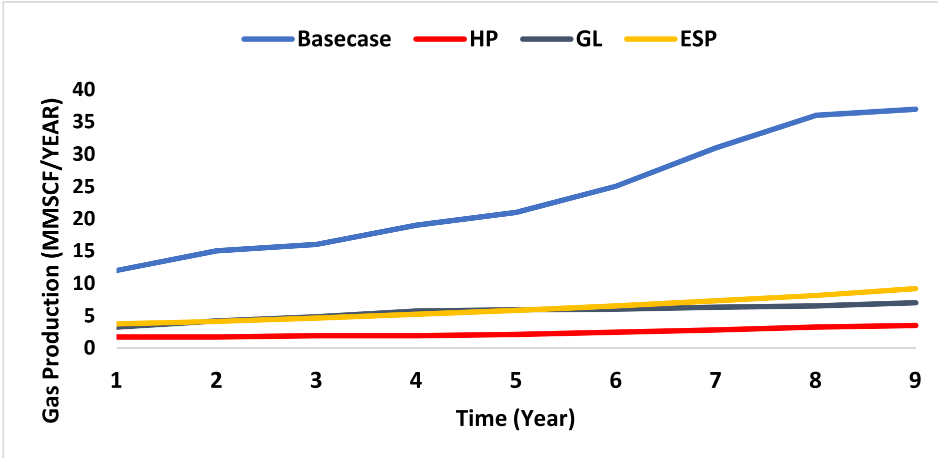

Fig. 11. Presents the base-case, ESP, GL, and HP Performances of Well2 in terms of gas production rate versus time

4.1.6 Simulation results of water production for well 1

Fig. 12. presents the base-case, ESP, GL, and HP Performances of Well2 in terms of Water Production (WPR) versus time. For base-case production, it was observed that Water breakthrough occurred after 2 years and increases throughout the period of production. For GL and HP productions, Water breakthrough also occurred after 2 years and increased till the end of production with a tremendous increase on ESP scenario.

4.1.7 Net present value (NPV) results at 15% discount rate

The economic results obtained in terms of Net Present Value (NPV) at the discounted rate of 15% shows that GL well 1 and ESP wells (Well 1 and well 2) will be profitable because their NPVs are positive. Hence, GL well 2 and HP wells (Well 1 and well 2) will not be profitable in terms of any investment because their NPVs are negative at the discounted rate of 15% Fig. 13. Here, the wells in green indicate that the project will be profitable and those in red indicate that the project will not be profitable.

4.1.8 Net present value (NPV) results at 25% discount rate

The NPV at the discounted rate of 25% shows that only ESP wells (well 1 and well 2) will be profitable because their NPVs are positive. Both GL and HP wells will not be profitable in terms of any investment because their NPVs are negative at the discounted rate of 25% Fig 14.

4.1.9 Internal rate of return (IRR) at 15% discount rate

The economic results obtained in terms of IRR at the discounted rate of 15% shows that GL well 1 and ESP wells (well 1 and well 2) will be profitable projects because their discounted rates that will be required to generate NPVs of zero are greater than the given discounted rate (15%). The GL well 2 and HP wells (well 1 and well 2) will not be profitable in terms of any investment because their IRRs are below the given discounted rate (15%), Fig. 15. Here, the wells in green indicate that the project will be profitable and those in black indicate that the project will not be profitable.

4.1.10 Internal rate of return (IRR) at25% discount rate

The IRR at the discounted rate of 25% shows that only ESP wells (well 1 and well 2) will be profitable because their IRRs are above 25%. Both GL and HP wells will not be profitable in terms of any investment because their IRRs are below 25%, Fig. 16.

4.1.11 Profitability index (PI) at 15% discount rate

The economic results obtained in terms of PI at the discounted rate of 15% is presented in. It shows that at 15% GL well 1 and ESP wells (well 1 and well 2) will be profitable projects because their PIs are greater than 1. The GL well 2 and HP wells (well 1 and well 2) will not be profitable in terms of any investment because their PIs are less than 1 at the discounted rate of 15% Fig 17.

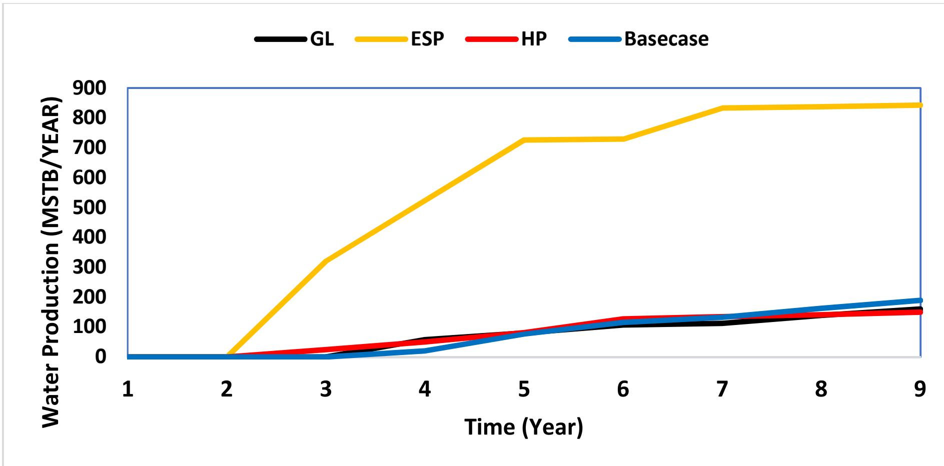

Fig. 12. Presents the base-case, ESP, GL, and HP Performances of Well2 in terms of water production rate versus time

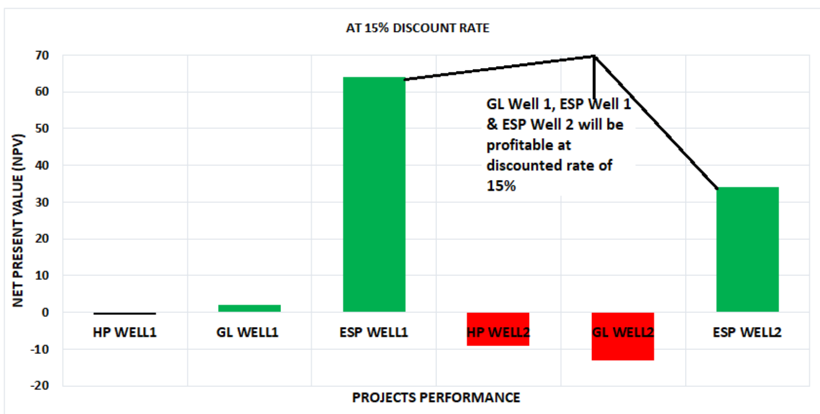

Fig. 13. NPV @ 15% discount rate

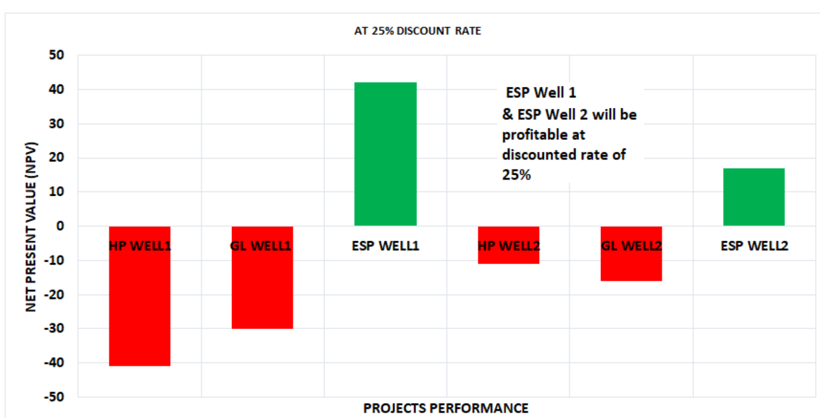

Fig. 14. NPV @ 25% discount rate

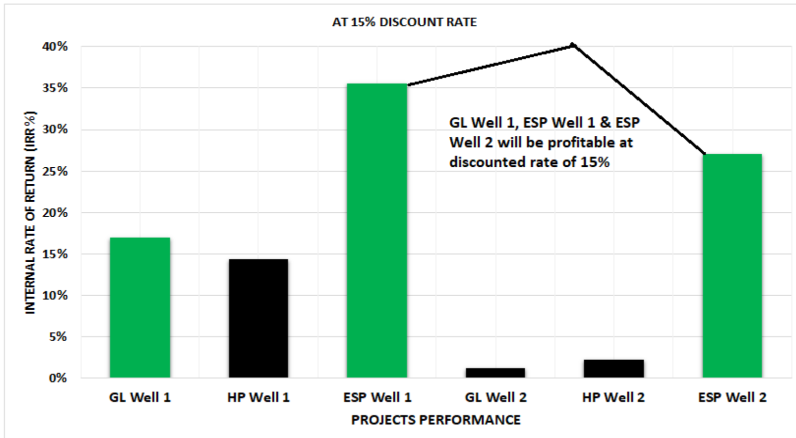

Fig. 15. Plot of IRR @ 15%

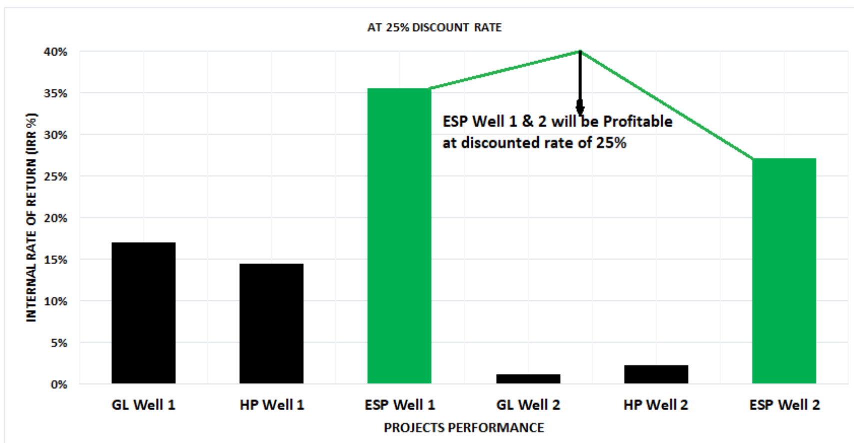

Fig. 16. PLOT Of IRR @ 25%

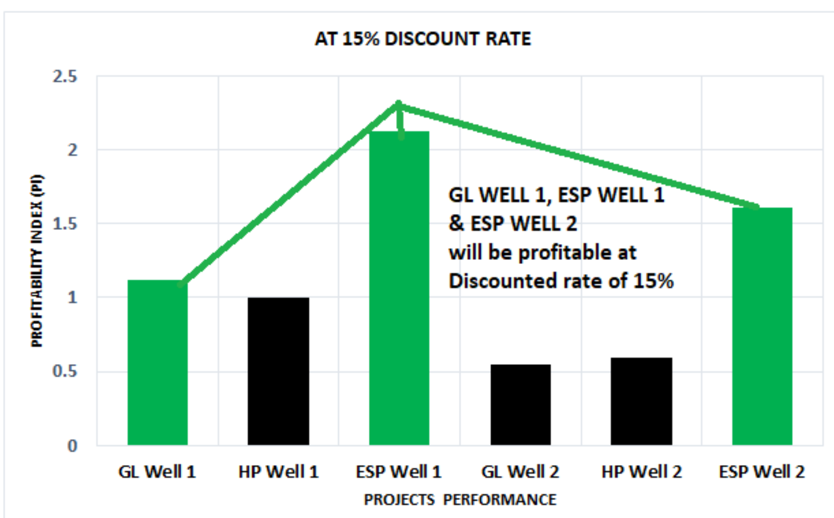

Fig. 17. Profitability index @ 15% discount rate

4.1.12 Profitability index (PI) at 25% discount rate

The PI at the discounted rate of 25% shows that at only ESP wells (well 1 and well 2) will be profitable and both GL and HP wells will not be profitable in terms of any investment because their PIs are less than 1 at the discounted rate of 25% Fig. 18.

4.1.13 Economic analysis result

To analyze the economic viability of these projects, three economic indicators, Net Present Value (NPV), Profitability Index (PI) and Internal Rate of Return (IRR) were employed to assess the profitability of the projects. For the Net Present Value analysis, it was observed that at 15% discount rate, GL well 1 and ESP wells (well 1 and 2) will be profitable because their NPVs are positive. When a discounted rate of 25% was used, it was observed that only ESP wells (well 1 and 2) will be profitable because their NPVs are positive. Both GL and HP wells will not be profitable in terms of any investment because their NPVs are negative at the discounted rate of 25%. For the Internal Rate of Return analysis, it was observed that at 15% discount rate, GL well 1 and ESP wells (well 1 and 2) will be profitable because their discounted rates that will be required to generate NPVs of zero are greater than the given discounted rate (15%). When a discounted rate of 25% was used, it was observed that only ESP wells (well 1 and 2) will be profitable because their discounted rates that will be required to generate NPVs of zero are greater than the given discounted rate (25%). Both GL and HP wells will not be profitable in terms of any investment because their IRRs are below the given discounted rate (25%). For the Profitability Index analysis, it was observed that at 15% discount rate, GL well 1 and ESP wells (well 1 and 2) will be profitable because their PIs are greater than 1. When a discounted rate of 25% was used, it was observed that only ESP wells (well 1 and 2) will be profitable because their PIs greater than 1. Both GL and HP wells will not be profitable in terms of any investment because their PIs are less than 1 at the discounted rate of 25%. Figs 19 and 20 presented the overall performances of well1 and well2 in terms of gas production rate (GPR), oil production rate (OPR) and water production rate (WPR) versus time respectively.

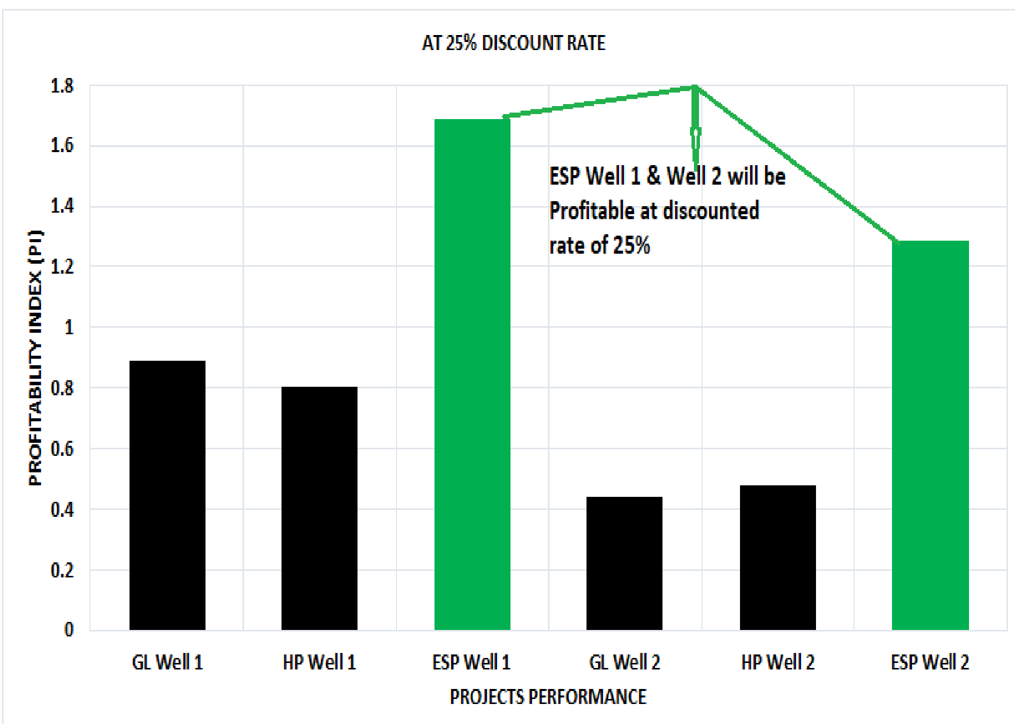

Fig. 18. Profitability index @ 25% discount rate

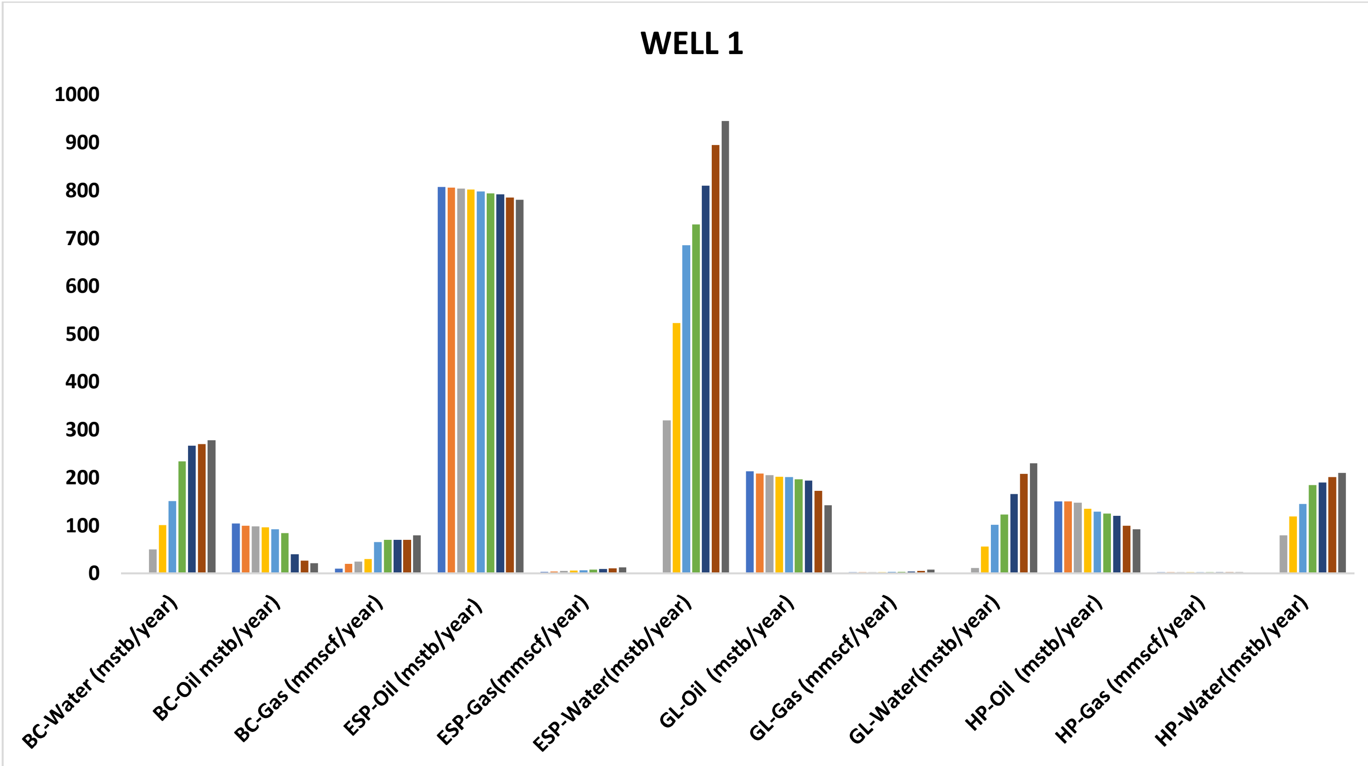

Fig. 19. Presents the base-case, ESP, GL, and HP Performances of Well1 in terms of oil, water and gas production rates

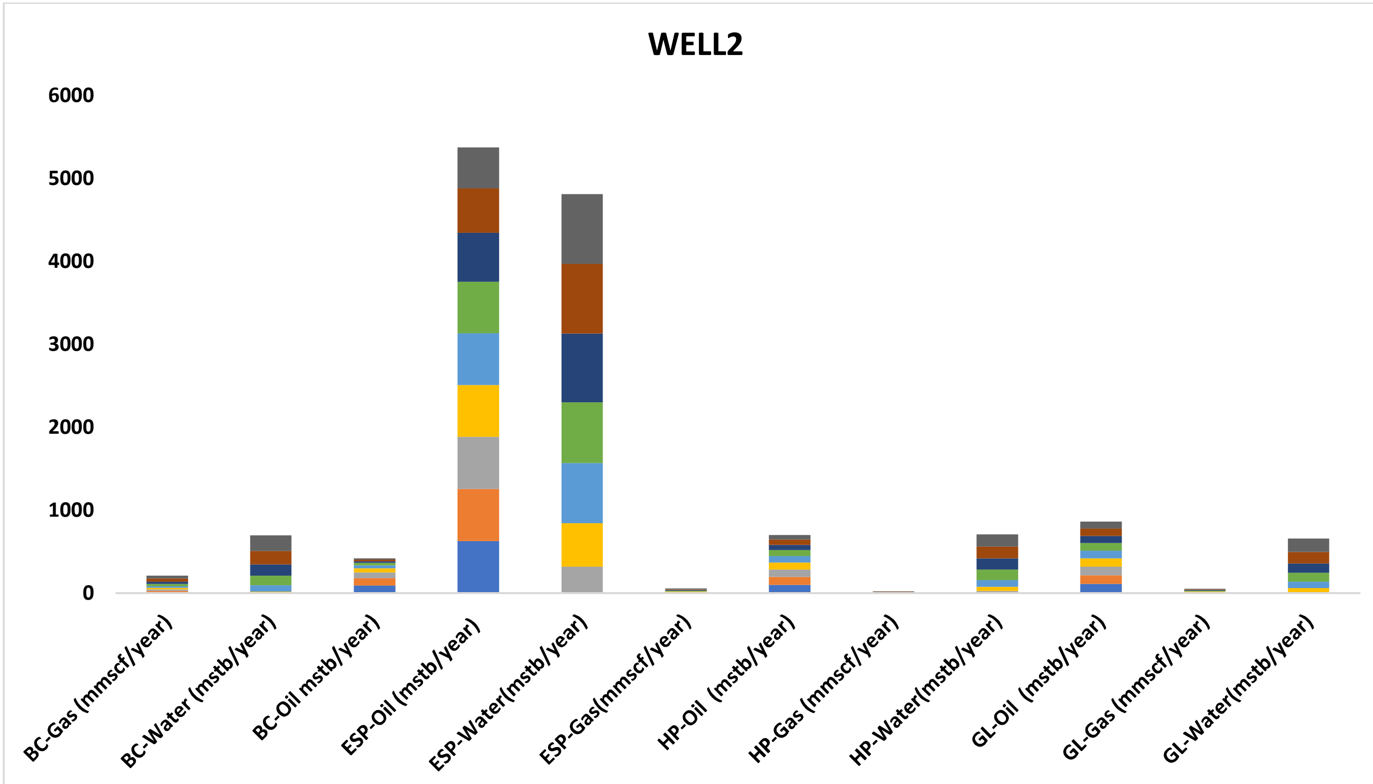

Fig. 20. Presents the base-case, ESP, GL, and HP Performances of Well2 in terms of oil, water, and gas production rates

5. CONCLUSION

From this study the following conclusions can be made:

1. The base-case oil production for well1 dropped from 104,000 stb/year to 21,000 stb/year (about 80% decline) and that of well 2 dropped from 92,000 stb/year to 14,000 stb/year (about 85% decline) after nine years of production period.

2. The HP well1, oil production dropped from 150,000 stb/year to 92,000 stb/year (about 39% decline) and that of well 2 dropped from 100,000 stb/year to 56,000 stb/year (about 44% decline) after nine years of production period.

3. The GL well 1, oil production dropped from 213,000 stb/year to 142,000 stb/year (about 33% decline) and that of well 2 dropped from 111,000 stb/year to 86,000 stb/year (about 23% decline) after nine years of production period.

4. The ESP well 1, oil production dropped from 807,000 stb/year to 781,000 stb/year (about 3% decline) and that of well 2 dropped from 630,000 stb/year to 497,000 stb/year (about 21% decline) after nine years of production period.

The Simulation results obtained from the production forecast showed that the ESP wells gave a highest oil production when compared to HP, GL and wells. Hence, the ESP technology proved to be the best technology for sustaining high production rate, increasing revenue and proved to be economically viable in Niger Delta oil fields though the electrical faults that may be associated with from time to time was not put into consideration.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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