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Effective Marginal Field Production Using Electric Submersible Pump: Niger Delta Case Study

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

Operators often abandon marginal field development and production to find reliable and available equipment and services to enable the field to be developed. These challenges make it difficult to produce such fields economically. This research uses industry-based simulators (PIPESIM, INTERSECT, and PETREL) to design a well-completion with an electric submersible pump (ESP) and simulate to evaluate the performance of ESP on a typical marginal oilfield. INTERSECT software was used to describe the reservoir. PIPESIM was used to design the artificial lift system of the wells (ESP), and PETREL was used to integrate the entire system for effective production optimization. Three economic indicators, Net Present Value (NPV), Profitability Index (PI), and Internal Rate of Return (IRR), were used to analyze the economic viability of these projects. The performance of the electric submersible pump (ESP) wells was simulated and compared with the performance of the natural flowing wells and the projected production forecast. The results obtained

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from the production forecast showed that the ESP wells provided superior oil production compared to the unassisted natural flow conditions. ESP-assisted wells increased production at an average rate of 400% of the natural flow capacity to the surface flow network. The cumulative production increase was 392% during the simulated period of 5023 days before a significant production decline occurred in the ESP's performances. The economic analysis indicated that all wells assisted with ESPs are profitable at 12%, 15%, and 20% discounted rates, representing the operator's capital cost. All NPVs are positive, with PI greater than 1. For IRRs, the IRR values for ESP wells were observed to be between 20.1 and 45.83%, which are higher than the discounted rates of 12%, 15% and 20%. Furthermore, the study's findings offer new and exciting ways to develop and transform abandoned oilfields into productive and economically sustainable marginal oilfields.

Keywords: Marginal field; electric submersible pump; gas-oil-ratio.

1. INTRODUCTION

In Nigeria, marginal field oil production is projected to account for about four percent of total hydrocarbon production [1]. The marginal field has been defined by many researchers under different lights. Among the many definitions, a marginal field is an oilfield that may need more positive income to make the field worth developing at a particular time and may not have been tapped for a long time [2]. Francis and Wokoma [3] defined marginal oilfields as the terminal point in the life of all mature producing oilfields before they are abandoned as uneconomical by operators. Marginal fields are small and mature fields that have been produced for a long time with low production rates and limited reserve [4]. Bertomeu et al. [5] opined that marginal field operators are mindful of identifying and implementing redevelopment strategies to improve production. Additionally, extending the productive life of the marginal field while maximizing the economic value of the field asset is a factor to consider in marginal development. Akpanika and Udoh [6] maintained that marginal fields are characterized by low production rates, fewer reserves, and uneconomical to develop and produce using conventional means of production. According to Dagogo et al. [7], marginal fields are oilfields with an uneconomical reserve when produced by major operators. Still, they are profitable when operated and managed by local indigenous players because of low overhead and operating costs. Marginal field development has considerable potential for global hydrocarbon output [8]; however, the development of marginal oil and gas fields is lagging due to several challenges despite respective government policy initiatives [9].

According to Ayuk [10], while there may be challenging fixes to the challenges facing the energy industry in Africa, developing marginal fields is a valuable strategy that can yield tangible benefits for the countries of the continent that embrace it. Ayuk [10] further said that the time to embrace it is now. The marginal field development initiative was introduced in Nigeria in 1996 to grow the country's oil and gas industry [10]. The significant objectives of developing marginal fields and increasing production and the base of petroleum reserves through the initiative have yet to be achieved [11]. This may be connected with the several challenges facing the development of marginal fields in Nigeria, as has been identified by several scholars. Kulasingam et al. [2] asserted that in addition to the challenges of technical capability and finance, other issues affecting marginal field development include:

i. finding reliable and available equipment and services to enable the field to be developed.
ii. obtaining export capacity in the oil pipelines operated by the IOCs, especially where the negotiating strength of a marginal field operator is not significant.
iii. dealing with pipeline losses and how these will be allocated to the operators who feed into the pipeline and
iv. dealing with local communities and community issues.

Ibibo [12] added more challenges to marginal field development, including a harsh production environment, counterproductive pronouncements and actions by regulators.

With the diminishing chances of new frontiers, there is an urgent need to optimally redevelop marginal fields with suitable methods that can bring about incremental hydrocarbon recovery that adds value to both reserve and production targets to provide reasonable economic incentives and profitability to the operator [13,14].

Advanced technology will be needed to optimize the marginal field. Woodman et al. [15], in the article titled 'Using Advanced Technology *to Increase Production in Marginal Fields,'* stipulated that a reduced set of changes of the control variable yields an increase in production short of the optimum.' Krukrubo's work was limited to gas lift applications with its complexities that encompass processing surface facilities that become difficult to manage in production optimization algorithms, according to Woodman et al. [15].

From all indications, researchers and operators agree that there is a need to overcome the technical challenges of producing and enhancing marginal field production. Oruwari [16] agrees that marginal field developers and development must embrace productivity improvement tools for sustainable production. However, there needs to be a suggestion of what those productivity improvement tools should be. Babadagli [17] opined that two well and reservoir engineering approaches have been suitable for developing mature and declining fields to extend the field life and increase recovery. Some well and reservoir engineering methods available to redevelop marginal and mature fields include enhanced oil recovery, such as water flooding, chemical or gas injection, and reservoir management systems: application of artificial lift technology [18]. Hassan et al. [19] identified a combination of water injection and artificial lift techniques as a technically feasible and economically attractive integrated approach to developing a marginal field. Therefore, approaches such as the downhole water sink (DWS) and the downhole water loop (DWL) are effectively added when the phenomenon of water conduction is envisaged [20,21]. The marginal field requires the development of non-conventional technologies. Hence, it has many technical limitations [22]. Kahali et al*.* [22] further listed two types of artificial lift methods to deliver marginal fields. The identified artificial lift methods are the gas lift method and the electric submersible pumping method. Artificial lift technologies are used in oil and gas to produce hydrocarbons and general fluid from wells [23]. Technology is a good redevelopment strategy for marginal fields with depleted pressure and insufficient potential to lift the desired well fluid to the surface [18,24]. Thus, the artificial lifting technique is preferred to continue the marginal field production. According to Tayyab et al. [23], the artificial lift technique is used in different forms. These forms include electric submersible pumping systems, gas lift technology, and hydraulic pumping systems [25,26].

1.1 Marginal Field Development and Production in the Niger Delta

The selection of artificial lift systems for marginal field development and production is based on several factors, which include the well conditions, the composition of the well fluid, and the desired production requirements. One field that fits the description is the field used for this study. This marginal field ABC is located in the Niger Delta. Five oil-producing wells are projected to cease production and render the asset uneconomical if nothing is done to sustain or increase the production from the existing wells and the field. The field began production with a total daily rate of 27MBPD, which declined to 18.3MBPD after 850 days of the first oil. This represents a 32% decline in production capacity, which necessitated a need for an economically viable means to boost production. Researchers have evaluated the use of several artificial lift methods in Niger Delta development in the past. Enwere et al*.* [27] evaluated the viability of six different types of artificial lift methods in eight different fields of the Niger Delta. In another study, Ndubuka and Akpabio [28] compared the operations of three artificial lift methods of ESP, hydraulic pump, and gas lift in a typical Niger Delta oilfield. Irrespective of the several studies evaluating the applicability of the various artificial lifts methods in the Niger Delta oilfields development and production, the use of the gas lift method has been predominant [29,30,31,32] All the studies agree that using the gas lift method in the production of marginal oilfields of the Niger Delta is limited by several constraints, including a decline in production caused by the decline in reservoir pressure and an increase in water-cut that could lead to field abandonment. Faseemo et al. [33] opined that there is potential for the deployment of ESPs to redevelop mature/marginal fields and restart wells to recover from a high-water-cut hydrocarbon formation. Additionally, ESPs are preferable for marginal field redevelopment because they can lift well fluids efficiently from challenging wells and harsh environments [18]. Both studies by Enwere et al*.* [27] and Ndubuka and Akpabio [28] also concluded that ESP was the best artificial lift method to enhance production in the marginal fields of the Niger Delta.

Hence, this study aims to showcase how to effectively enhance the production of a Niger

Delta marginal oilfield using ESP deployment as an artificial lift method. ESPs are useful in marginal field redevelopment projects, especially in fields where depletion with a hugely lower reservoir pressure has made it difficult to produce the hydrocarbon deposit to the surface [4,26]. ESPs can be used in marginal field redevelopment projects to increase production capacity and extend the productive life of the marginal field by overcoming the constraints that have limited the use of gas lift methods in the Niger Delta marginal fields. Therefore, in this study, the use of electric submersible pumps to enhance the production from the existing wells in the field is conducted in addition to economic evaluation to determine the viability of using ESPs as a form of artificial lift means to enhance the production of the marginal field. There is minimal attention to using the ESP artificial lift method in developing, redeveloping, and sustaining production in the marginal fields of the Niger Delta region. Therefore, this research will demonstrate the application of an electric submersible pumping (ESP) system in enhancing marginal field production using a case field from the Niger Delta.

1.2 ESP Application in the Niger Delta

In marginal fields, the challenges of increasing hydrocarbon production are common in the oil and gas industry and field development for both ‘green’ and ‘brown’ fields. Challenges are associated with efforts to develop, maintain, or sustain a desired production target, whether a naturally flowing well or an artificially lifted hydrocarbon well. These challenges affect the well-completion system's lifespan and the general marginal field. The decline in reservoir pressure over the life of the field could cause an increase in the produced water-cut accompanied by a decrease in the gas ratio. This combination could cause the well to stop producing the desired production target to the surface. The decline in production from the desired rate will mean the inability to deliver fluid to the collecting facility through the production pipelines [34]. Operators often abandon marginal field development and production because of the complexities and challenges facing marginal field operations. These challenges make it difficult to produce such fields economically. The number one challenge Kulasingam et al. [2] identified is finding reliable, available equipment and services to enable marginal field development. Challenges such as technological limitations impede indigenous oil and gas companies from effectively producing marginal fields [10,22]. Sinulingga and Yananto [35] proposed a low capital cost and low maintenance cost pipeline technology to economically develop, produce and maintain a marginal field with high CO_2 content through a 6.3 km 8-inch pipeline. One sure way to avoid the decline in hydrocarbon production and failure of completion equipment is by optimization or production enhancement [36,26,37]. It is, therefore, imperative to identify the best technological approach to develop and produce marginal fields, thereby overcoming the technical challenges of producing marginal fields from the start. The approach must be reliable and cost-effective. According to Onwuemene [38], the technical approach to re-enter and produce a marginal field must be cost-effective with comparatively reduced capital outlay and risk exposure. Unfortunately, the nearest technical approach prevalent in the Niger Delta has been the gas lift method of artificial lift. The method still needs to enhance marginal field productivity in the long term [29,30,31,32].

2. METHODOLOGY

This research used commercial simulators (PIPESIM, INTERSECT and PETREL) to design a well-completion with ESP and simulate and evaluate ESP performance on a marginal oilfield in the Niger Delta. Five oil wells were simulated, and their production performance was evaluated. Well production outputs were optimized using ESP. INTERSECT software was used for reservoir description. PIPESIM was used to design the wells' artificial lift system (ESP), and PETREL was used to integrate the entire system for production optimization. It involved an outline description of the different methods applied and the procedures undertaken to arrive at the study's objectives effectively. Simulations and history matching were completed using the software packages to achieve the best fit for the production forecasts. The packages for volumetric estimate relied on the original oil in place, N of the undersaturated oil reservoir, generally calculated by Eq. 1:

$$N = \frac{7758\varphi hA\left(1-S_{wi}\right)}{B_{oi}} \tag{1}$$

where:

N - Original oil in place, STB
7758- Number of barrels per acre-foot, bbl/acre-ft

A- Area of the zone, acres
h- Average net thickness of the zone, ft
φ- Porosity, Unitless

B_{oi} - Oil formation volume factor at initial reservoir pressure, bbl/STB
S_{wi}- Water saturation at initial reservoir conditions, Unitless.

Economic indices such as net present value (NPV), profitability index (PI), and internal rate of return (IRR) were used to assess the profitability of the ESP technique in analyzing the economic viability of this study. The formulas adopted in the estimates are:

$$NPV = \frac{R_t}{(1+i)^t} \tag{2}$$

PI = NPV of future Cash Inflows/Initial Cash Outlays

IRR = NPV = 0

where:

R_t - Net cash flow at time t
i - Discount rate
t - Time of the cash flow

The data sets used in this study were obtained from a marginal oilfield operating in the Niger Delta.

Table 1. Fluid and reservoir data

Parameters	Well-1	Well-2	Well-3	Well-4	Well-5
GOR, scf/STB	800	392	900	760	570
API	35.0	37.7	40.0	42.0	39.0
Water Gravity	1.02	1.02	1.02	1.02	1.02
Gas Gravity	0.74	0.75	0.8	0.87	0.75
Oil Density, lb/ft^3	41.0	46.0	50.0	49.0	48.0
Oil FVF, RB/STB	1.3	1.3	1.5	1.4	1.1
Oil viscosity, cP	0.6	0.6	0.6	0.6	0.6
Oil Compressibility, psi^{-1}	1.0	1.0	1.0	1.0	1.0
Gas Density, lb/ft^3	14	12.9	13.9	11	12.2
Gas viscosity, cP	0.3	0.2	0.21	0.31	0.4
Gas FVF, ft^3/scf	0.006	0.006	0.006	0.006	0.006
Water Density, lb/ft^3	65.0	64.0	64.0	64.0	64.0
Water viscosity, cP	1.1	1.1	1.1	1.1	1.1
Water FVF, RB/STB	1.000	1.01	1.02	1.02	1.4
Water salinity, ppm	80000	80000	80000	80000	80000
Overall heat, $BTU/H/FT^2/^oF$	3.0	3.0	3.0	3.0	3.0
Cp Oil, BTU/lb/F	0.5	0.5	0.5	0.5	0.5
Cp Gas, BTU/lb/F	0.5	0.5	0.5	0.5	0.5
Reservoir pressure, psi	3200	3000	2900	3100	3300
Wellhead Pressure, psi	300	450	302	303	304
Reservoir temperature, ^oF	150	160	155	155	170
Water cut, %	50	55	60	60	58
Reservoir permeability, mD	600	600	600	600	600
Reservoir thickness, ft	100	110	90	90	112
Drainage area, acres	250	250	250	250	250
Wellbore radius, ft	0.5	0.5	0.5	0.5	0.5
Skin	1.0	1.0	1.0	1.0	1.0
Porosity, fraction	0.3	0.3	0.3	0.3	0.3
Connate Water, fraction	0.3	0.3	0.3	0.3	0.3
Original oil in place, MMSTB	2000	2000	2000	2000	2000
Initial Gas Cap	0	0	0	0	0

Table 2. Additional modeling data

Casing Data	Value	Tubing Data	Value
Casing ID, inches	8.681	Tubing ID, inches	3.476
Casing wall thickness, inches	0.472	Tubing wall thickness, inches	0.262
Casing bottom MD, ft	9100	Tubing bottom MD, ft	8550
Casing roughness, inches	0.001	Tubing roughness, inches	0.001
Fluid Model PVT Parameter		**Additional Data**	
Gas Solubility, scf/bbl	800	Packer depth, ft	8500
Formation Volume Factor, bbl/stb	1.3	IPR model	Well PI
Gas Specific Gravity	0.75	Average Permeability, mD	600
Water Specific Gravity	1.0	Average porosity, fraction	0.3
API	39.0		
Viscosity, cP	0.6	**Heat Transfer Data**	
Datum depth, ft	8820	Heat transfer coefficient, Btu/h/°F/ft^2	2.0
Reservoir Pressure, psia	4000	Wellhead ambient temperature, °F	30
Reservoir Temperature, °F	200		

2.1 Field Production System Modeling

The field is located about 20 km from the nearest gathering facility. The field reservoir is an unconsolidated sandstone formation type bearing a crude API range of 35 to 42. The PVT data is shown in Tables 1 and 2. The reservoir is water-wet with naturally behaving fluid. The five wells in the marginal field were drilled and produced to deliver to the nearest gathering facility until the water-cut increase resulted in a sharp decline in production from these wells. Hence, there was the need to determine a means to revitalize the wells or abandon the field in no distant time as the decline continued. To achieve the focus of this study, the design and selection of completion ESP assembly and simulation is based on the available data in Tables 1 and 2 with assumptions based on industry guidelines.

3. RESULTS AND DISCUSSION

The production performances of the marginal field on natural, free flow and ESP-assisted flow were simulated and evaluated for the five wells in the field based on the recorded production rates available at the time of the study. The available records show the production rates at 6000 stb/d, 4000 stb/d, 4000 stb/d, 8000 stb/d and 5000 stb/d for Well-1, Well-2, Well-3, Well-4 and Well-5, respectively, at the inception of production of each well. Since the wells were flowing, there was no doubt about the inflow capabilities of the wells. The production performances of the reservoir and the wells at inception and after on natural flow and ESP-assisted flow were simulated. All the results from the simulations are presented and discussed in the following sections.

3.1 Production Performance of the Wells on Natural Flow

By matching the IPR and the VLP through the available data set, the natural flow rate and corresponding bottomhole pressures were simulated and presented. Table 3 presents the results of the sensitivity performances of Wells-1 through Well-5 on natural, free flow before ESP was applied to enhance the production performance of the wells. Table 3 shows that the production rate of Well-1 is 1373 stb/d with a corresponding flowing bottom-hole pressure of 2800 psi. The production rate for Well-2 is 777 stb/d with a corresponding flowing bottom hole pressure of 2612 psi. For Well-3, the production rate is 867 stb/d with a corresponding flow bottom-hole pressure of 2601 psi, and the production rate of Well-4 is 799 stb/d with a corresponding flow bottom-hole pressure of 2834 psi. From the same Table 3, the production rate of Well-5 is 933 stb/d with a corresponding flowing bottomhole pressure of 3026 psi. From the simulation, bottom-hole pressures varied from one well to another across the field. Ndubuka and Akpabio [28] agree with the findings that the well location and aquifer support play a big role in the output of each well. The different rates and bottom-hole pressures observed from each well can be attributed to the drainage effect on the reservoir section where the wells were spudded [7].

Table 3. Production performance of wells at the base condition

Name	Flow rate (stb/day)	BHP (psi)
Well-1	1373.01	2800.00
Well-2	776.5164	2611.742
Well-3	867.2926	2601.112
Well-4	799.3701	2833.543
Well-5	932.7202	3025.671

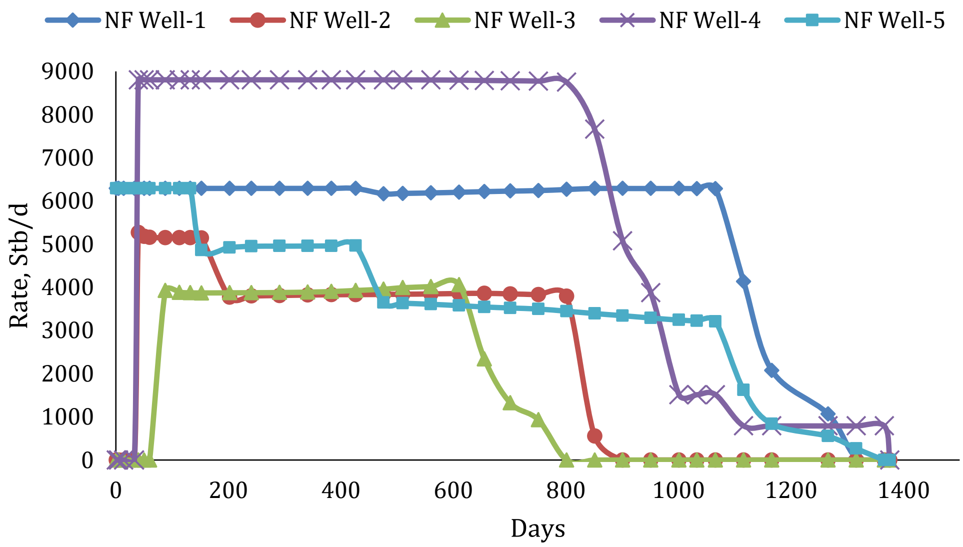

Fig. 1. Overall production profile of the wells on natural flow

3.2 Overall Production Profile of the Wells on Natural Flow

Fig. 1 presents the result of the simulation of the natural flow production profile of Well-1 to Well-5 in the marginal field. Fig. 1 shows the production lifespan of each of the wells in the marginal field based on the production performance profile on natural, free flow. Fig. 1 shows that under natural flow conditions, the wells stopped production due to insufficient energy to sustain production from the subsurface to the surface at varied times. From the simulation results, it can be seen that Well-1 was producing a constant amount of 6000 stb/d before ceasing to flow after 1360 days. A similar trend was observed in Well-2. Well-2 started with 5000 stb/d for the first 180 days, then declined to 3800 stb/d before ceasing to flow after 850 days. From the same Fig. 1, Well-3 was observed to have started with 3900 stb/d, then declined to 1000 stb/d before ceasing to flow after 801 days of coming on stream. Well-4 with a constant production of about 8800 stb/d, then declined sharply to cease flowing after 1376 days of production. Finally, from the same Fig. 1, Well-5 was observed to produce initially at 6200 stb/d, then decline to 5000 stb/d and 3200 stb/d before ceasing to flow after 1366 days of coming on stream. Well-3 recorded the lowest days of production time with only 801 days. The decline of most of the wells after about 1110 days made the marginal field unattractive to produce on natural flow. This is in line with what was reported by other studies: the natural flow mechanism decreases over time as the production rates increase, which eventually hampers the natural hydrocarbon production rate and profitability of the field [39,40,29].

3.3 ESP Assisted Production Profile of the Wells

Fig. 2 presents the simulation result of the production profile of Well-1 to Well-5 when assisted with ESP. Fig. 2 presents the general results of the production performance profile of all Wells (1 to 5) assisted with ESP. In Fig. 2, it was observed that the production capacities of the wells were enhanced after the installation of ESPs. From the simulation results, Well-1 was at a constant production of 6200 stb/d for 1066 days before gradually declining to 1450 stb/d after about 3507 days before declining significantly to an uneconomical production rate after 5023 days. Similar decline trends were observed in Well-2, Well-4, and Well-5, with their respective production rates declining to 893 stb/d, 1032 stb/d, and 905 stb/d, respectively after 5023 days of production. Well-3 production, on the other hand, increased from the initial 3900 stb/d to a stable production rate of 6200 stb/d before declining to 4500 after 5023 days of field life production. Using ESPs to assist the fluid flow in the wells helped extend the production capacity, the production lifespan of the wells, and the field asset in general. This outcome is consistent with the work of other authors [41,28].

3.4 Production Profile of the Wells for Natural and ESP Flows

Figs. 3 to 7 present the results of the simulation of the production performance, and Fig. 3 presents cumulative profiles of Well-1 to Well-5 for both natural and ESP-assisted flow. Fig. 3 shows that the incremental oil production of Well-1 was optimized after the installations of ESP, and the economic productive run-life was enhanced. From the simulation results, Well-1, under natural flow conditions, ceased production after 1360 days, but the life of the well was extended to 5023 days when assisted with ESP. In Fig. 4, the productive life of Well-2 was enhanced from 850 days on natural flow to 5023 days on the ESP-assisted production profile. From Fig. 5, the production of Well-3 under natural flow terminated after 801 days. Still, under the ESP-assisted condition, the well's production life was extended to 5023 days with reasonable production capacity. In Fig. 6, it was observed that ESP deployment enhanced the well's production life from 1376 days on natural flow to 5023 days before declining substantially. In Fig. 7, it was observed that the incremental oil production of Well-5 was enhanced after the installation of ESP, like in the rest of the wells in the field. From Fig. 7, it can be seen that the use of ESP enhanced the well's production life from 1366 days on natural flow to 5023 days before experiencing a significant decline in production rate.

Spiked gas-oil-ratio (GOR) was seen in the production profiles of Well-2, Well-3, and Well-5 sustained below the solution GOR of the well fluid (Figs. 4 to 7). These spikes further resulted in better production from those wells. A phenomenon corroborated by Ndubuka and Akpabio [28], which often occurs in the production life of some wells because of their location in the reservoir. From the simulation results shown in Fig. 8, the cumulative oil production from the naturally flowing Well-1 was 7,093,618 stb, while that obtained from the ESP-assisted Well-1 was 18,685,677 stb (about 163% oil increment of the natural capacity). The cumulative oil production from natural flow Well-2 was 3,092,583 stb, while that obtained from ESP-assisted Well-2 was 15,279,778 stb (representing 394% oil increment). The cumulative oil production from natural flowing Well-3 was 22,267,511 stb, while that obtained from ESP-assisted Well-3 was 25,525,934 stb (representing about 1026% oil increment on the natural flow capacity). The cumulative oil production from natural flowing Well-4 was 7,943,535 stb, while that obtained from ESP-assisted Well-4 was 22,850,489 stb (representing 188% oil increment on the natural flow capacity). In the same Fig. 8, the cumulative oil production from natural flowing Well-5 was 4,1679,868 stb, while that obtained from ESP-assisted Well-5 was 15,906,042 stb (about 240% oil increment).

By considering the production profile and desired rate analysis of ESP for effective production of the marginal oilfield, the ESP system can increase oil production while prolonging the marginal field life. The outcome of the evaluations of the marginal field well production performance under natural flow and ESPs was divergent, as observed in Figs. 3 to 7, and in agreement with the work of other researchers [14, 28]. The use of ESPs improved the performance of the individual and collective well deliverability due to their ability to have a large displacement and high net lift in line with the findings of other authors [42,14]. While the wells declined and stopped production from 800 days, as seen in Well-3, to 1376 days, as in Well-4, under natural flow conditions, ESPs sustained production from each well and the field for more than 15023 days before a substantial decline was observed. This ensured production sustainability, which Basil and James [43] enumerated as a challenge to marginal field operators. They maintained that more than 70% of marginal field operators could not achieve the first oil and sustain production for more than a year.

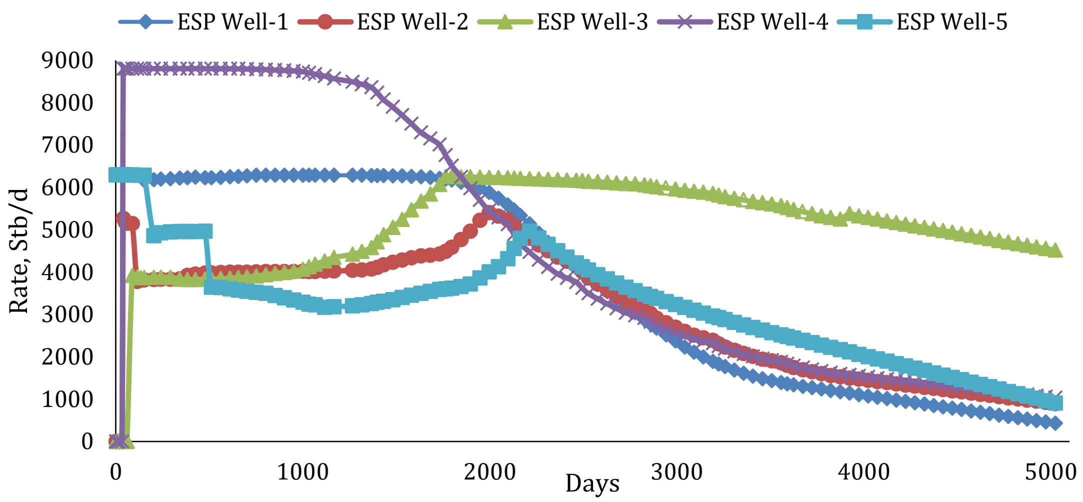

Fig. 2. ESP-assisted production profile of the wells

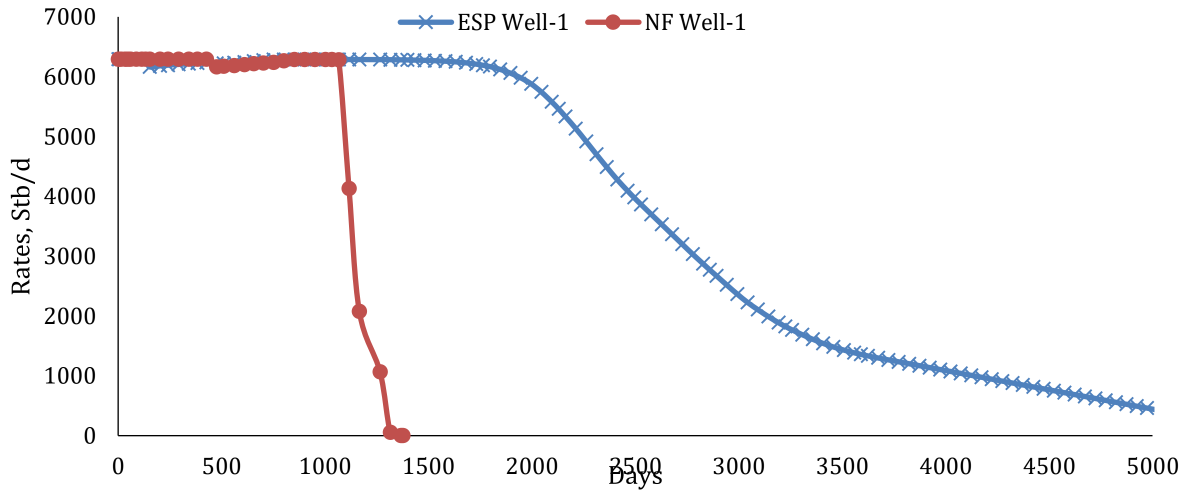

Fig. 3. Well-1 production performance profile for natural and ESP flow

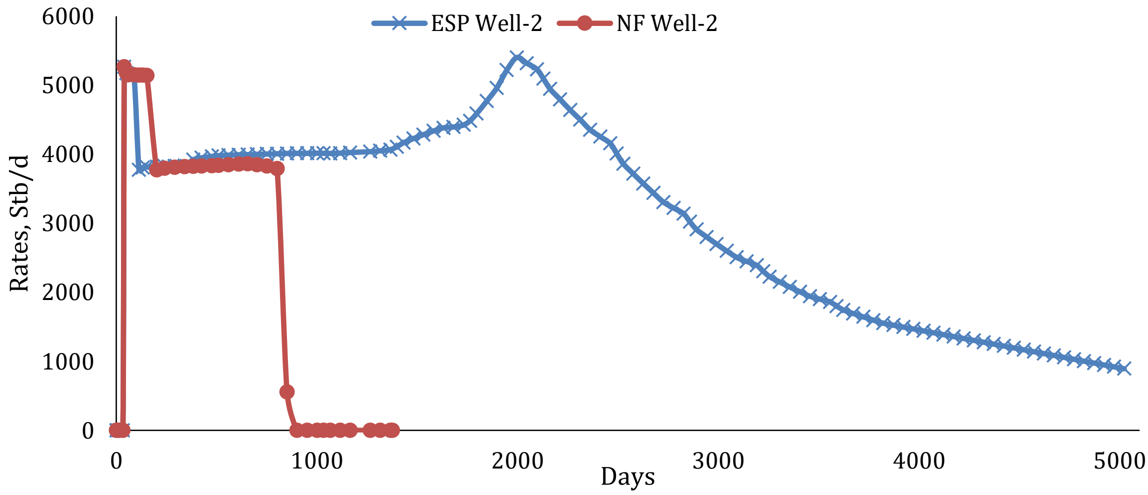

Fig. 4. Well-2 production performance profile for natural and ESP flow

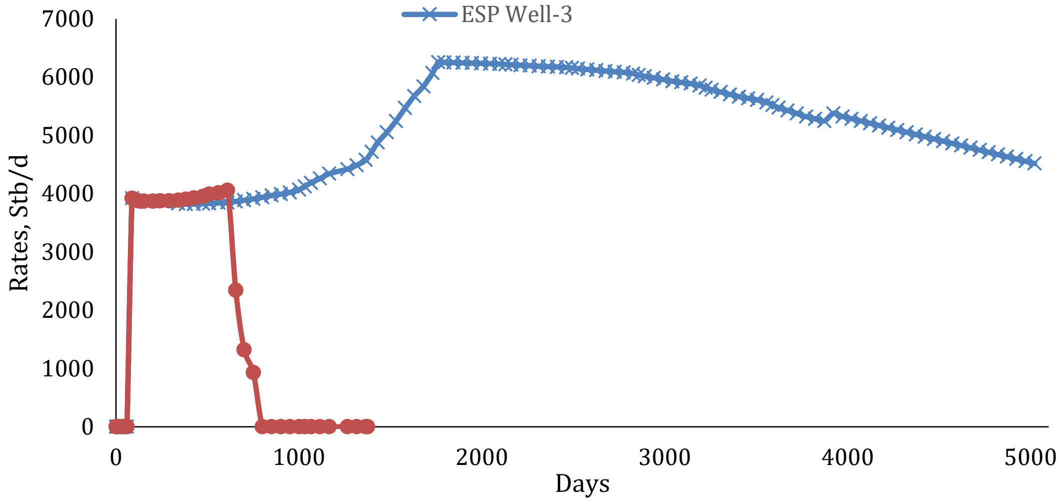

Fig. 5. Well-3 production performance profile for natural and ESP flow

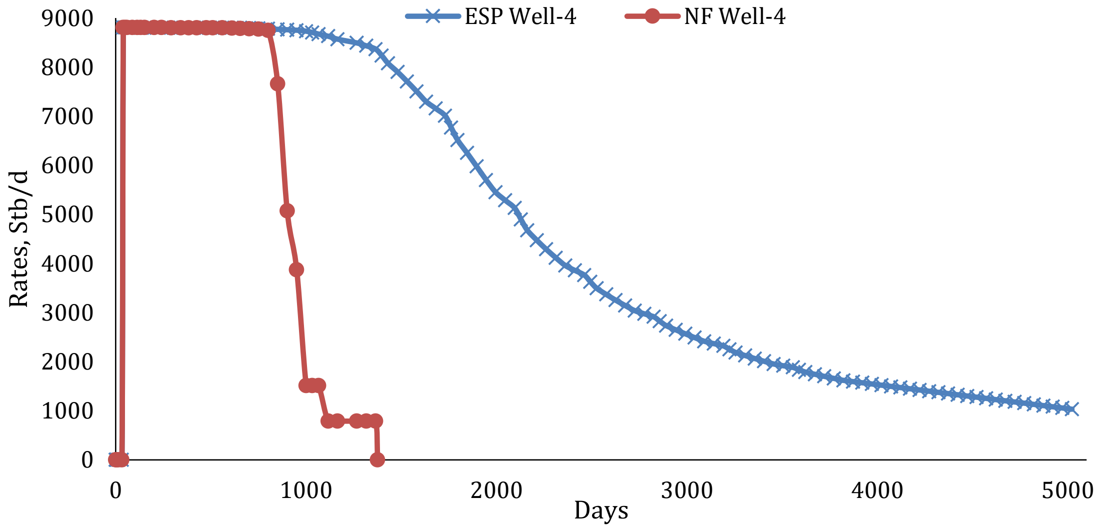

Fig. 6. Well-4 production performance profile for natural and ESP flow

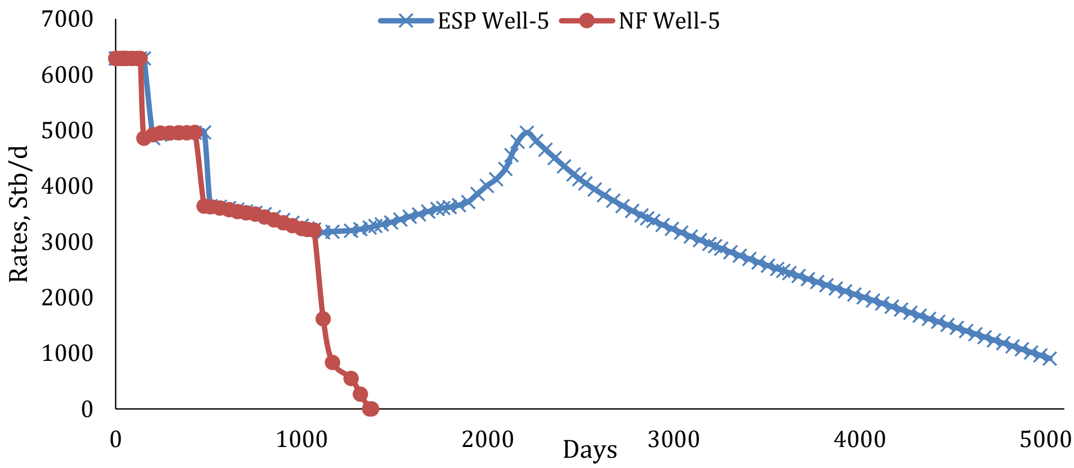

Fig. 7. Well-5 production performance profile for natural and ESP flow

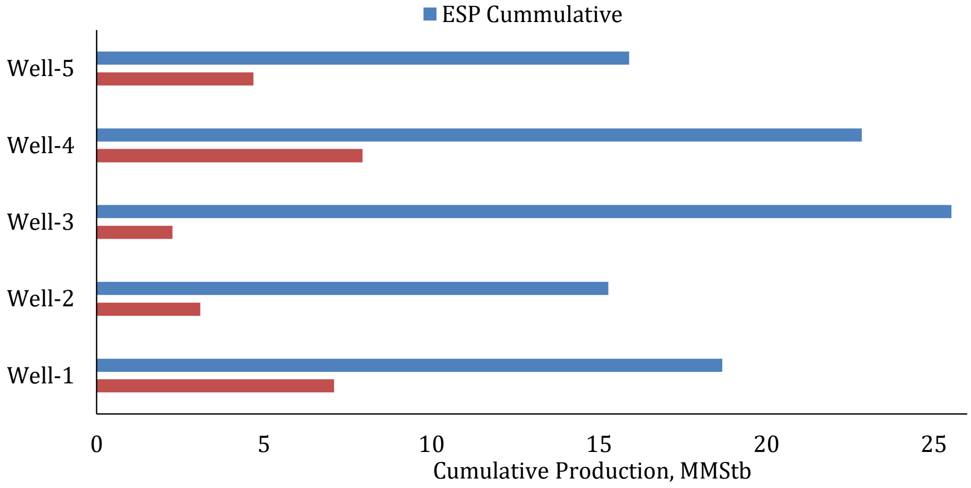

Fig. 8. Total production for natural and ESP flows

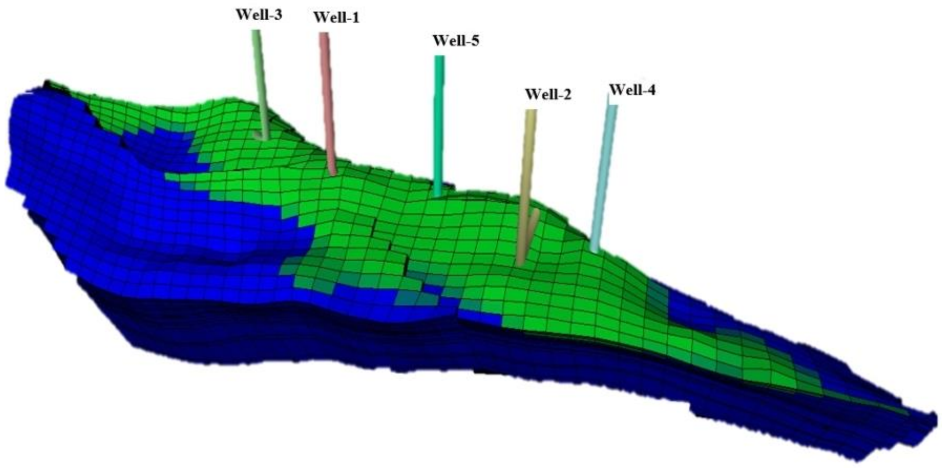

Fig. 9. Reservoir drainage on natural flow

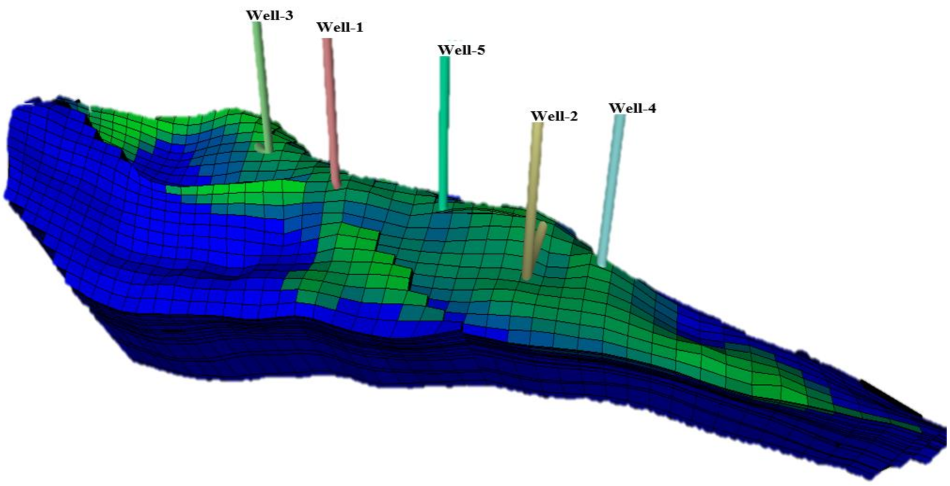

Fig. 10. Reservoir drainage with ESP-assisted flow

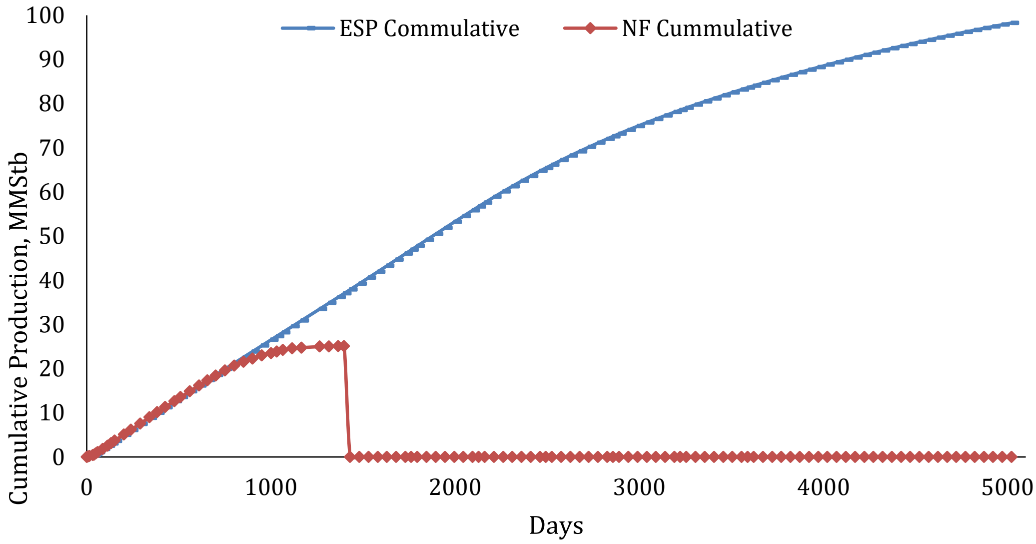

Fig. 11. Cumulative oil production profile with and without ESP

3.5 Cumulative Production for Natural and ESP-Assisted Flows

Figs. 9 and 10 show the results obtained regarding the reservoir drainage for the natural and ESP-assisted flow, respectively. Fig. 11, however, shows the cumulative recovery from the field for both natural and ESP-assisted flows. Figs. 9 and 10 showed that the reservoir drainage using ESP was more effective than that from natural flow. There were different percentages of recovery from each of the wells based on their different locations on the reservoir grid. In Fig. 11, the incremental oil production after the installation of ESPs is higher than that of natural flowing wells. The simulation results showed that the cumulative oil recovery on natural flow unassisted was 25,077,114.400 stb. In comparison, that recovered with ESP assisted as at the 1366 days when all NF wells were projected to stop was 37,018,876.221 stb (representing about 50% oil increment) and the overall cumulative production at the end of the simulated days of 5023 was 98,347,920 stb, representing about 392% oil increment. The results obtained from the production forecast showed that the ESP-assisted wells provided superior oil production and better reservoir drainage irrespective of the well placement (which often affects reservoir drainage sensitivity) [6] compared to the natural flowing wells. This conforms with the finding of Jamie et al. [44], who opined that ESPs improve the recoverability of field developments.

3.6 Economic Analysis of ESP Wells

The results of the economic analysis of using ESPs to enhance marginal field production in the Niger Delta basin are presented below. Using the cash flows estimated for natural flow and ESP, the internal rate of returns (IRR) of the project was calculated, as well as the Net-Present Value (NPV) and Productivity Index (PI) of the project using 12%, 15% and 20% discount rates per the respective formulas as embedded in Microsoft excel worksheet. The subsequent sections present a discussion on the economic analysis results of using ESPs to enhance marginal field production in the Niger Delta basin. The entire economic analysis was conducted per Jamie et al.'s [44] approach to evaluate the economic performance of using ESP for field development by comparing the value of the increased recoverable against the costs of installation and operations to demonstrate its profitability.

3.6.1 Net present value (NPV) at discounted rates

The economic results obtained in terms of Net Present Value (NPV) at the discounted rate of 12%, 15% and 20% are presented in Figs. 12 to 14 and summarized in Table 4. Fig. 12 shows that at a discount rate of 12%, all the wells were profitable because their NPVs were positive. Fig. 13 shows that at a 15% discount rate, all wells were profitable with positive NPVs. Fig. 14 shows that at a 20% discount rate, all the wells were profitable with positive NPVs. The outcome of positive NPV for profitability conforms with the work of other authors [41,7,45]. Rustam et al. [46] concluded that a project using ESP for production becomes unprofitable when the cost outweighs the revenue generated.

3.6.2 Profitability index (PI) at discounted rates

The economic results obtained in terms of PI at the discounted rate of 12%, 15%, and 20% are presented in Table 5 and Figs. 15 and 16. Fig. 15 shows that all ESP-assisted wells are profitable projects because their PIs are greater than one at a 12% discount rate. Fig. 16 shows that all ESP-assisted wells are profitable projects at a discount rate of 15% because their PIs are greater than 1. In Fig. 17, at a discount rate of 20%, all ESP-assisted wells are profitable projects because their PIs are greater than 1. The project of utilizing ESP to enhance the productivity of the field is profitable, with PI greater than 1 in line with the work of other authors [7,45,28].

Table 4. Net Present Value (NPV) at Discounted Rates

NPV	Well-1 (MM$)	Well-2 (MM$)	Well-3 (MM$)	Well-4 (MM$)	Well-5 (MM$)
12%	8.61	2.79	4.75	10.50	4.13
15%	7.13	1.59	2.96	8.77	2.93
20%	5.14	0.002	0.69	6.43	1.35

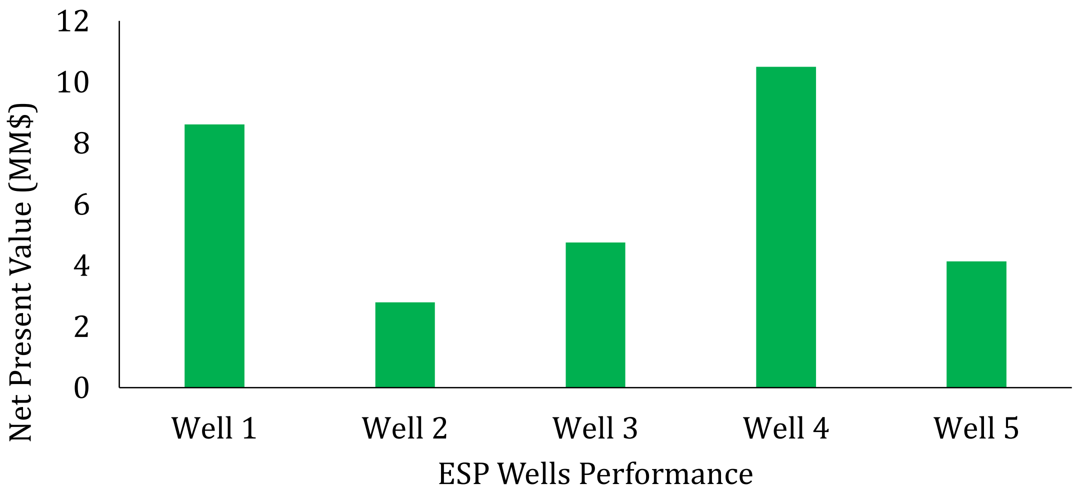

Fig. 12. Net Present Value (NPV) at 12% discount rate

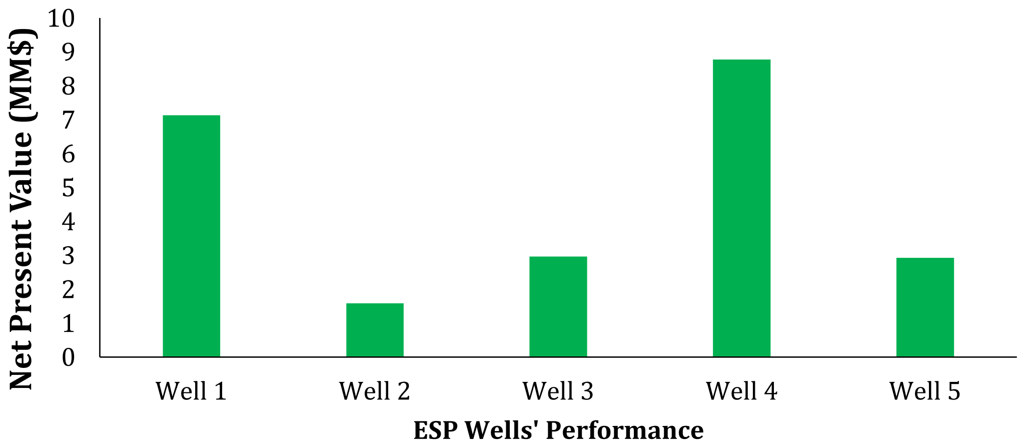

Fig. 13. Net Present Value (NPV) at 15% discount rate

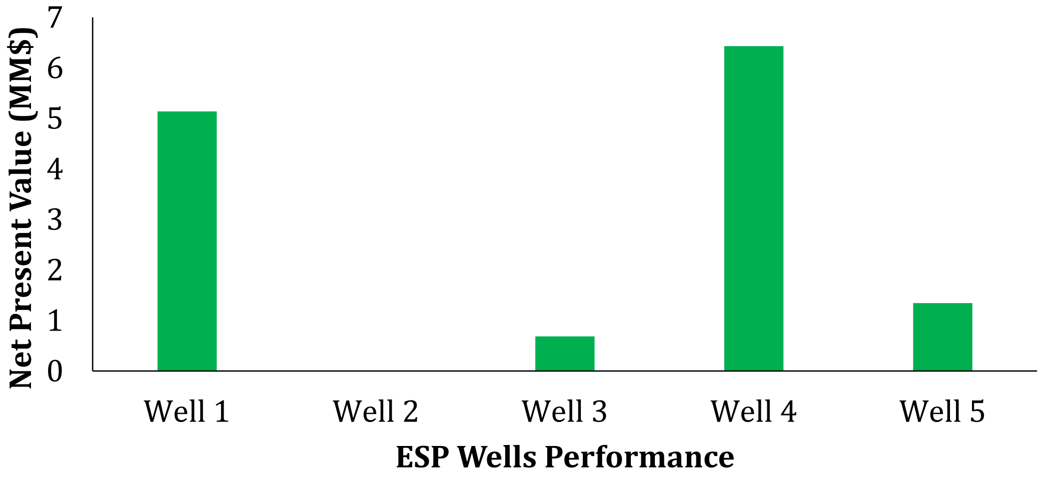

Fig. 14. Net Present Value (NPV) at 20% discount rate

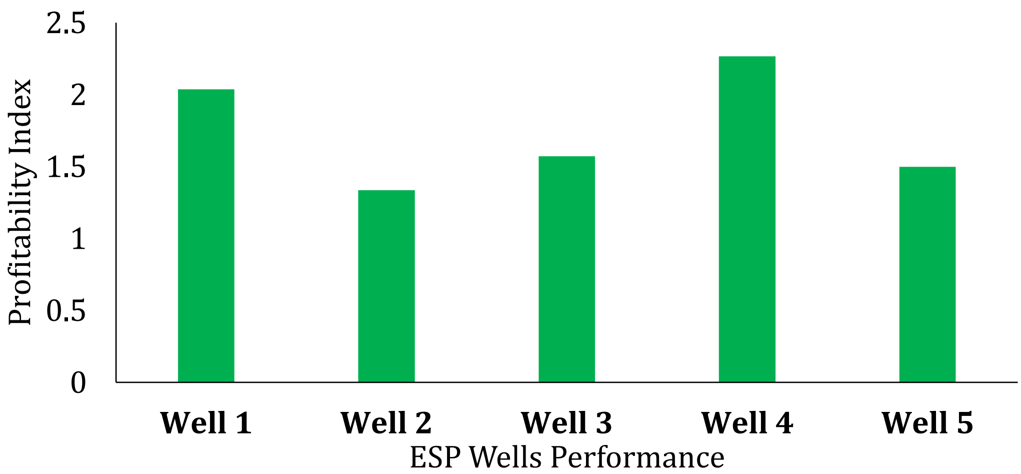

Fig. 15. Profitability Index (PI) at 12% discount rate

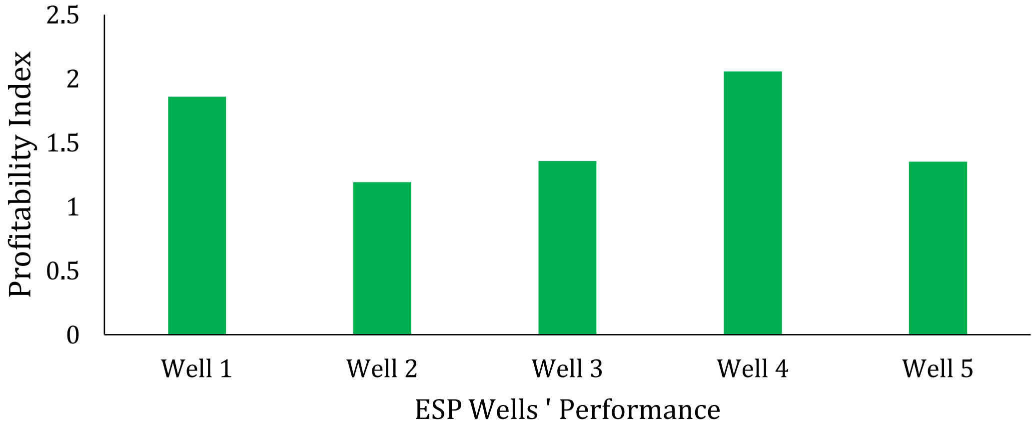

Fig. 16. Profitability Index (PI) at 15% discount rate

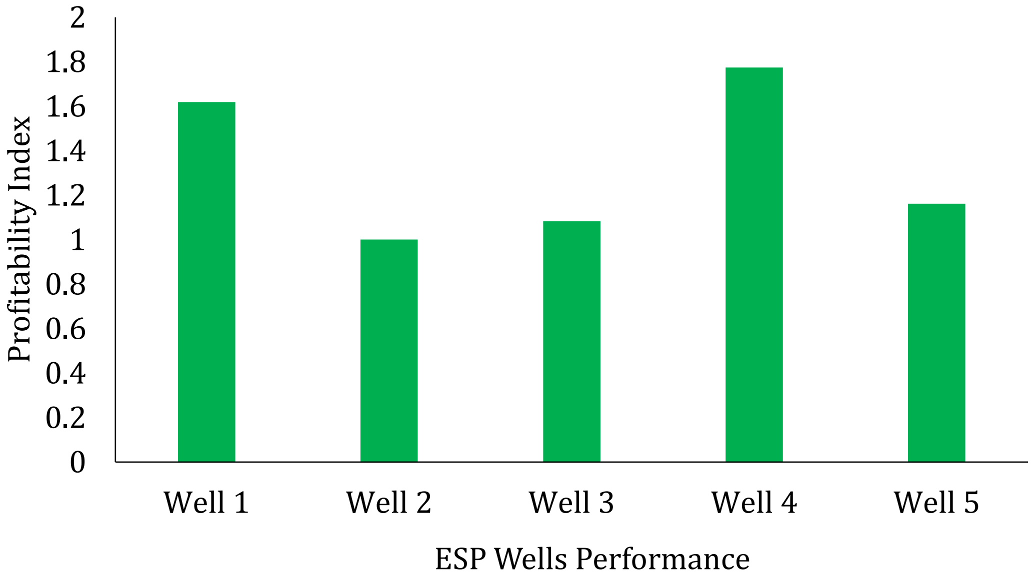

Fig. 17. Profitability Index (PI) at 20% discount rate

Table 5. Profitability Index (PI) at discounted rates of 12%, 15%, and 20%

PI	Well-1	Well-2	Well-3	Well-4	Well-5
12%	2.037	1.337	1.573	2.265	1.498
15%	1.859	1.191	1.357	2.057	1.353
20%	1.619	1.000	1.083	1.775	1.162

Table 6. Internal rate of return of each Well

Name	Well-1	Well-2	Well-3	Well-4	Well-5
IRR	43.09%	20.01%	21.90%	45.83%	25.73%

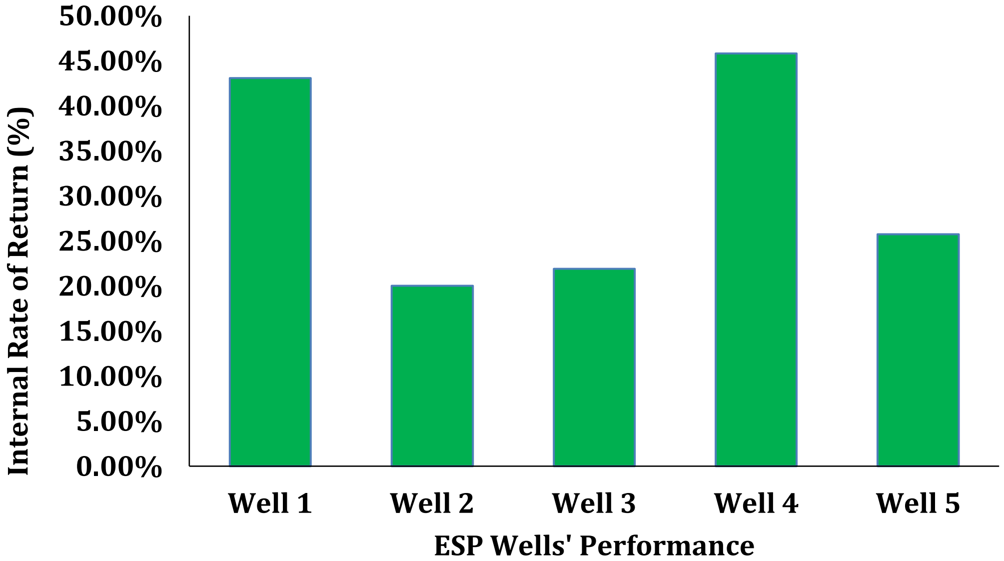

Fig. 18. Internal Rate of Return (IRR) per well assisted by ESP

3.6.3 Internal rate of return (IRR) at discounted rates

The economic results obtained in terms of IRR at discounted rates per well are presented in Table 6 and Fig. 18. In Table 6 and Fig. 18, it was observed that 43.09% is the discounted rate that will be required to generate NPVs of zero for ESP Well-1. Any discount rate above 43.09% will make ESP Well-1 unprofitable. For ESP Well-2, it was observed that 20.01% is the discounted rate required to generate NPVs of zero. Any discount rate above 20.01% will make ESP Well-2 unprofitable. For ESP Well-3, it was observed that 21.90% is the discounted rate required to generate NPVs of zero. Any discount rate above 21.90% will make ESP Well-3 unprofitable. For ESP Well-4, 45.83% was observed, and 45.83% is the discounted rate required to generate NPVs of zero. Any discount rate above 45.83% will make ESP Well-4 unprofitable.

For ESP Well-5, it was observed that 25.73% is the discounted rate that will be required to generate NPVs of zero. Any discount rate above 25.73% will make ESP Well-5 unprofitable. The evaluation conducted in this study showed that all wells have their IRR above their respective capital cost. Hence, using ESPs to assist field production is a profitable venture. This finding conforms with the results from other authors [28,7,45]. Rodrigo [47] states that a project would be considered uneconomical if the generated IRR is less than the capital cost.

4. CONCLUSION

There is minimal attention to using the electric submersible pumping system (ESP) artificial lift method in the development, redevelopment, and sustain production in the marginal fields of the Niger Delta. Hence, the research focused on applying ESPs to effectively enhance marginal field production using data from a case field from the Niger Delta. Technical and economic analyses were conducted to highlight the benefit of ESPs in marginal field production enhancement and asset longevity and viability.

Commercial petroleum industry packages were used to conduct the technical evaluation of the marginal field potential through sensitivity analysis of an electric submersible pumping system. PIPESM (2019 version) was used to model the wells and surface flow network. PETREL (2022.2 version) was used to model the reservoir dynamic behavior. INTERSECT (2021.3 version) was used to integrate PIPESIM and PETREL to simulate the entire field potential by interacting with the five wells and the reservoir. Production forecasts from each well were simulated, and the cumulative production and recovery from the reservoir were simulated and calculated. The Economic approach derived the economic indices of the production forecast from the modelled system. The following conclusions were drawn from the study:

i. The ESP system increased the production capacity of each well and the field as a result. The ESP-assisted wells' production increased at an average rate of 400% of the natural flow capacity to the surface flow network. Cumulative production from Well-1 increased by 163%, Well-2 increased by 394%, Well-3 increased by 1026%, Well-4 increased by 188%, and Well-5 production increased by 240%. The use of ESP provided a cumulative production increase of ca 392% during the simulated period of 5023 days before a significant production decline occurred in the ESPs of Well-1, Well-2, Well-4, and Well-5.
ii. The sensitivity analysis of the ESP performance with potential field constraints shows that the oilfield potential can be managed in the long run through accurate and timely optimization of the ESP operating efficiency and the completion tubing. ESP systems overcame the limitations to natural flow production caused by the following constraints: decrease in reservoir pressure, increase in wellhead pressure, and increase in water cut.
iii. The optimal conditions with maximal production were obtained when the ESP was at an operating efficiency of 70 Hz and wellhead pressure of 400 psi for a 4-1/2-inch tubular completion. 3-inch and 4-inch tubing performed better in all the wells than any other tubing size. On average, 4-1/2-inch tubing is produced at 2% more than 1-inch to 3-inch tubing and 4% more than 5-inch to 6-inch tubing, respectively.
iv. Economic analysis of well production with and without the aid of ESP indicates that the project will be profitable. At 12%, 15%, and 20% discount rates, all ESP wells will be profitable because their NPVs are positive and their PIs are greater than 1. For IRRs, it was observed that the IRR values for ESP wells are between 20.1 and 45.83%, which are higher than the

discounted rates of 12%, 15%, and 20% (representing the cost of capital). Hence, the field would be profitable to produce with the aid of ESPs.

v. Finally, the implementation of electric submersible pumping systems eliminated the need for infill drills to sustain the marginal field production, thereby reducing the cost and environmental impact of infill drilling. The deployment of ESP systems enhanced marginal field wells' production capacities and the operational lifespan of the field asset in an economically sustainable manner while contributing to the national and global oil and gas energy mix.

5. RECOMMENDATIONS

The study strongly believes that incorporating an electric submersible pumping system as a form of artificial lift technique in marginal field development of Niger Delta oilfields will effectively boost production and ensure production sustainability as the fields remain economically viable. Hence, the following recommendations are provided:

i. The deployment of ESPs should be spaced over time based on the performance of the various wells. The first ESP should be installed in Well-3 after 800 days of coming on stream. ESP should be installed in Well-2 after 850 days, that is 50 days after installing ESP for Well-3. Well-5 and Well-1 ESPs should be installed after 1260 and 1320 days of coming on stream, respectively, while Well-4 is installed after 1370 days.

ii. The first ESPs should be completed and replaced after operating for 3650 days, except for Well-3, to regain the efficiency of using ESPs. The ESPs should be installed deeper during the completion design to avoid gas breakout due to a decline in reservoir pressure.

iii. After 3650 days of operation using the ESP systems to maintain bottom-hole pressure and improve recovery, a water injection strategy may be implemented.

iv. Marginal field operators should consider deploying artificial lift technologies from the onset of their field development. An electric submersible pumping system, in particular, provides a high-volume lift that ensures timely recoup of investment.

v. The field in which an electrical submersible pump (ESP) is to be implemented should have a well-thought-out layout pattern for effective design and optimization. This will ensure proper utilization of top facility resources while draining the reservoir uniformly.

vi. The ESP's deployment and operational strategy should be evaluated for accurate and sustainable production before it can be applied for any marginal field production enhancement.

DISCLAIMER (ARTIFICIAL INTELLIGENCE)

Authors hereby declare that NO generative AI technologies such as Large Language Models (ChatGPT, COPILOT, etc.) and text-to-image generators have been used during the writing or editing of this manuscript.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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