Overcoming the Urge for Infill Drilling in Marginal Field Redevelopment through Artificial Lift Deployment

Kalu - Ulu, Torty C.[1], Okon, Anietie N.[2], Appah, Dulu[3]

[1]University of Uyo
Email: *tortyk1[at]yahoo.com*

[2]University of Uyo
Email: *anietieokon[at]uniuyo.edu.ng*

[3]University of Port – Harcourt
Email: *appah.dulu[at]ipsng.org*

Abstract: ***This study presents the use of electric submersible pumping (ESP) system, an artificial lift technique, to overcome the urge to drill infill wells in marginal oilfield redevelopment. A marginal field with three wells was modelled using PIPESIM and PETREL packages to simulate the natural flow and artificial lift contributions to the production life of a marginal oilfield in the Niger Delta. Sensitivity analysis of the marginal oilfield operating conditions was determined using the ESPs completion in sample wells to determine the optimal operating conditions and the field's productive life. From the sensitivity analysis, the ESP system increase the production rate from a would - be abandoned oilfield (i. e., 740 bbl/day) by 360%. Thus, the system produced the wells that the natural flow could no longer sustain. Also, the ESP completions maintained a positive output irrespective of the wellbore conditions, the flow network properties, the increased water cut, and reservoir pressure depletion. Again, the ESP system extends the marginal field production life by ten years, before declining to about 30% of its initial production capacity. From the results obtained, ESP applications on marginal field redevelopment and wells restart are viable and productive alternatives for any marginal oilfield operator caught in the middle.***

Keywords: Electric submersible pump, Marginal oilfield, oil production rate, Niger Delta region

1. Introduction

Marginal fields are small and mature fields that have been produced for a long time with low production rates and limited reserve (Idachaba and Wokoma, 2017). Bertomeu *et al*. (2015) opined that operator of marginal fields are mindful of identifying and implement redevelopment strategies to improve production. Also, extending the productive life of the marginal field while maximizing the economic value of the field asset is a factor for consideration in marginal development. Akpanika and Udoh (2008) maintained that marginal fields are characterized with low production rates, less reserves and uneconomical to develop and produce using conventional means of production. According to Dagogo*et al*. (2018), the marginal fields are the oilfields with an uneconomical reserve when produced by major operators but are profitable when operated and managed by local indigenous players because of low overhead and operating costs. 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 (Krukrubo, 2013). Babadagli (2005) opined the two approaches: well and reservoir engineering, suitable to develop mature and declining fields to extend the field life and increase recovery. Some of the well and reservoir engineering methods available to redevelop marginal fields and mature fields include enhanced oil recovery, such as water flooding, chemical or gas injection, and reservoir management systems: application of artificial lift technology (AlBallam*et al*., 2023). Hassan *et al*. (2001) identified a combination of water injection and artificial lift techniques as a technically feasible and economically attractive integrated approach to develop a marginal field. Therefore, approaches as downhole water sink (DWS) and downhole water loop (DWL) are effective to be incorporated when water coning phenomenon is envisaged (Okon*et al*., 2017; Okon and Appah, 2018).

Artificial lift technologies are commonly used in the oil and gas industry to produce hydrocarbon and general fluid from wellbores (Tayyab *et al*., 2016). The technology is a good redevelopment strategy for marginal fields with depleted pressure and insufficient potential to lift the desired well fluid to the surface (AlBallam*et al*., 2023). Thus, the artificial lift technique is preferred to continue the marginal field production. According to Tayyab *et al*. (2016), the artificial lift technique is used in different forms. These forms include electric submersible pumping systems, gas lift technology, hydraulic pumping systems, etc. (Zalavadia*et al*., 2023). The selection of artificial lift systems to apply is based on the wellbore conditions, well fluid composition, and desired production requirements. Faseemo*et al*. (2009) concluded that ESPs deployment to redevelop mature fields and restart wells to recover from high water cut hydrocarbon has potential.

ESPs are useful in marginal field redevelopment projects, especially in fields where depletion with hugely decreased reservoir pressure has made it challenging to produce the hydrocarbon deposit to the surface (Idachaba and Wokoma, 2017). Additionally, ESPs are preferrable for marginal field redevelopment because of their capacity to lift well fluids efficiently from challenging wells and harsh environments (AlBallam*et al.*, 2023). Therefore, ESPs can be used in marginal field redevelopment projects to increase the production capacity and extend the productive life of the marginal field. The systems can help to overcome the challenges of low reservoir pressure in marginal fields and produce the desired hydrocarbon to the surface more efficiently. This tends to increase well's production rate (Idachaba and Wokoma, 2017) while generating additional revenue to make the marginal field more economically viable. According to Li *et al.* (2018), ESP is effective for hydrocarbon production; it is necessary to note that its application in marginal field redevelopment demands thorough project planning and evaluation (Oyewole, 2016). Thus, some things to consider are wellbore construction, reservoir performance, fluid properties, and completion material specifications (Patron *et al.*, 2017). All these ensure the successful deployment and management of the ESP system in marginal field redevelopment to extend the field's production life. Therefore, sensitivity analyses based on wellbore conditions, reservoir pressure profile, and fluid properties are studied to determine the viability of ESPs as a form of artificial lift means for marginal field redevelopment in this paper.

2. Methodology

The methodology described here involved information from marginal oilfields in shallow waters of the Niger Delta region. The study used several industry - recognized modelling applications (software) to simulate the marginal field production performance on natural and electric submersible pump flows. The method was purely a technical analysis of the performance of the field under consideration. Well - completion software PIPESIM was used to design and model the electric submersible pumping system performance over time and different operating conditions of the marginal oilfield. At first instance, three wells without ESP completions were modelled and simulated to evaluate the marginal field production performance. Afterwards, the wells were modelled with ESP completions to conduct a sensitivity analysis of the marginal field. Again, PETREL software was used to integrate the flow network of the oil wells to effectively evaluate their contributions under the various constraints of the marginal oilfield. Sharma and Glemmestad (2014) affirmed the importance of conducting uncertainty and sensitivity analysis of ESP systems in oilfield applications. In this study, the constraints considered are reservoir pressure, water cut, and flow network backpressure. From the mentioned constraints, sensitivity analyses to determine the following on the marginal oilfield production rate and production life were performed:

1) The production profile of the wells on natural flow;
2) The production profile of the wells aided with ESPs;
3) The effect of ESP varying frequencies on the wells' production rates;
4) The effect of declining reservoir pressures on the wells' production rates;
5) The effect of wellhead pressure on the wells' production rates;
6) The effect of tubing diameter on the wells' production rates; and
7) The effect of increasing water cuts on the wells' production rates.

2.1 Field/Well Simulation Modelling

The marginal oilfield is an under - saturated black oil reservoir with initial parameters of mid - perforation reservoir pressure of 4000 psia, bubble pressure (P_b) of 2316 psia, oil API of 39, solution gas - oil ratio (GOR) of 1800 scf/stb, oil formation volume factor (B_{oi}) of 1.31 rb/stb. Other relevant details of the marginal field initial parameters are in Table 1. The production well details at the time of the study are visible in Table 2. From the available data and existing well - completion model in PIPESIM, the ESP configuration (model) is visible in Figure 1. The pump setting depth was at 8500 feet. The ESP system consists of a centrifugal pump connected to an electric motor to provide the electric force to rotate the pump to lift the well fluid. The electric motor's power supply was through a three - phase electric power cable. The ESP system hung on the well tubular to the surface wellhead hanger.

Table 1: Initial reservoir parameters

Parameters	Values
P_r (psia)	4000
P_b (psia)	2316
API	39
GOR (scf/stb)	1800
B_{oi} (rb/stb)	1.31
Porosity (%)	30
Mid - Perf (ft)	8800

Table 2: The marginal field well profiles

Parameters	Well - 1	Well - 2	Well - 3
GOR, scf/stb	800	392	900
API	35.0	37.7	40.0
Reservoir pressure, psia	3200	3000	2900
Reservoir Temperature, ^oF	150	160	155
Water cut, %	50	55	60
Skin	5	7	3
Wellhead pressure, psi	300	450	303

Paper ID: SR23624065052 DOI: 10.21275/SR23624065052

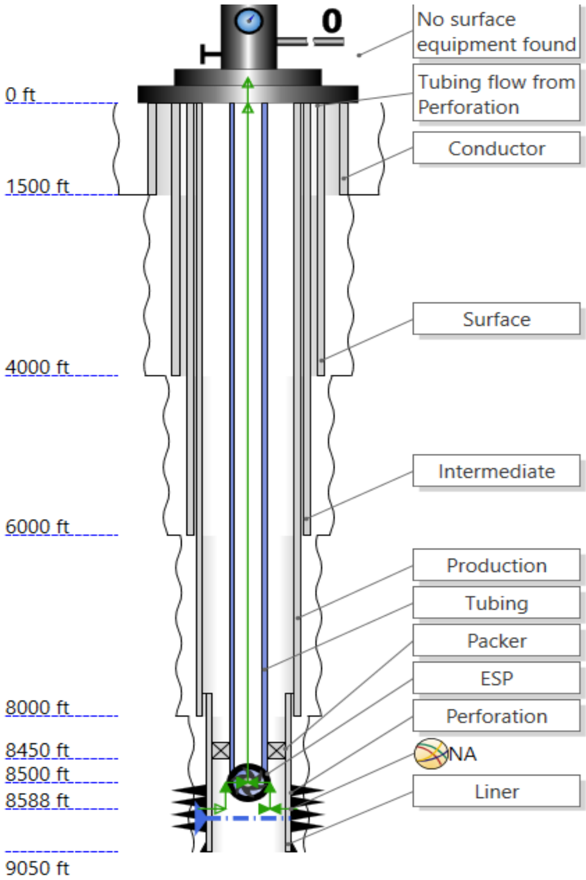

Figure 1: ESP Simulation Schematics

3. Results and Discussion

The marginal field production performance on natural flow and ESP assisted were simulated based on initial production data of the wells standing at 6289.78 stb/d, 5267.01 stb/d, and 3922.57 stb/d for Well - 1, Well - 2, and Well - 3, respectively as of January 2nd, 2020. In addition, ESP sensitivity analyses on the select constraints to the marginal field production were performed. The results obtained are presented and discussed in the following sections. The marginal field constraints analyzed include ESP motor frequency, decreasing reservoir pressure, increasing wellhead pressure, tubular diameter, and increasing water cut.

3.1 Production Performance of the Wellsbefore ESP Installation

Figures 2 through 4 present the results of the sensitivity performance of Well - 1 through Well - 3 before ESP was applied to optimize the production performance of the wells. In Figure 2, the oil production rate of Well - 1 was 1373 stb/d with a corresponding flowing bottom - hole pressure of 2800 psi (Table 3). Well - 2 oil production performance (in Figure 3) before the deployment of ESP installation showed that its production rate was 777 stb/d with a flowing bottom - hole pressure of 2612 psi (Table 3). Also, Figure 4 presents the production performance of Well - 3 before ESP was applied to optimize its production potential. From the figure, the Well - 3 production rate was 867 stb/d with a flowing bottom - hole pressure of 2601 psi (Table 3).

Table 3: Performance of Well - 1 before ESP

Well Name	Flow rate stb/day	BHP (psia)
Well - 1	1373	2800
Well - 2	776.5164	2611.742
Well - 3	867.2926	2601.112

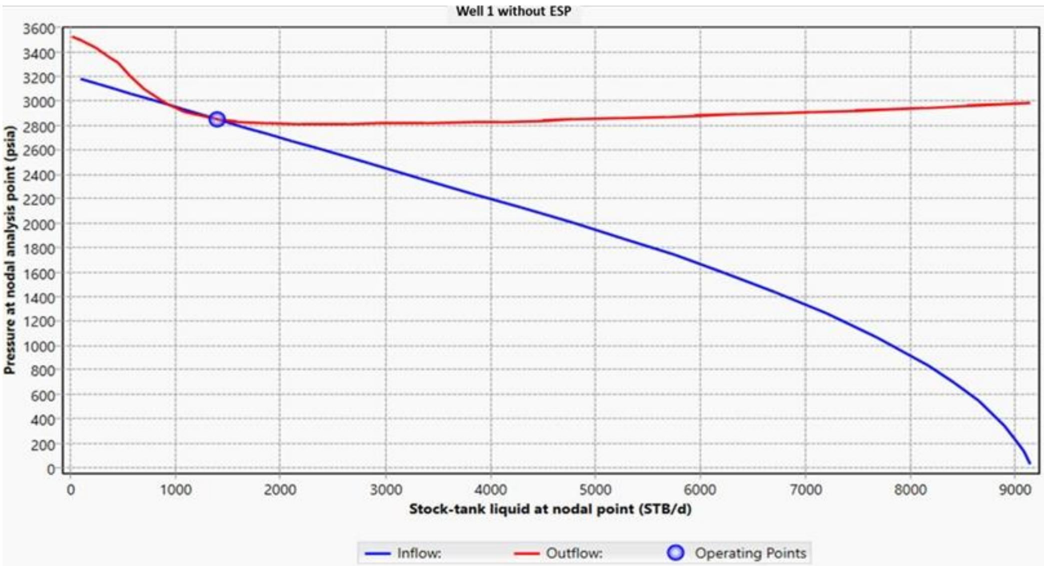

Figure 2: Production performance of Well - 1 before ESP installation

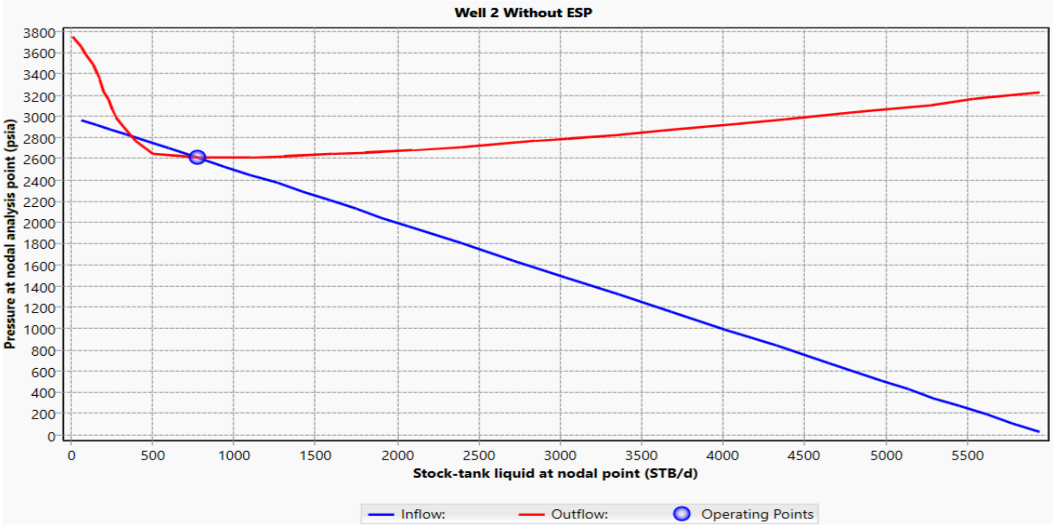

Figure 3: Production performance of Well - 2 before ESP installation

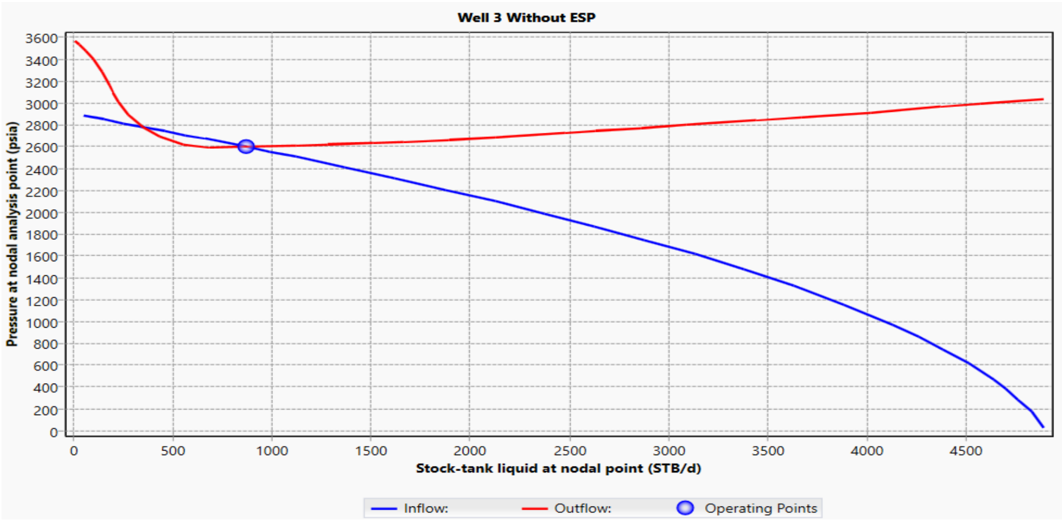

Figure 4: Production performance of Well - 3 before ESP installation

From the simulation of the wells on natural flow without the aid of the artificial lift method of electric submersible pumps, they produced remarkably well for two and a half years (as shown in Figure 5). The wells and the field, in general, are projected to stop production by late 2023 (Figure 5) from observed production performance and potential constraints of declining reservoir pressure, increasing wellhead pressure to sustain critical flow, and increasing water - cut. The signature of the marginal field well production performance under natural flow and ESPs were divergent, as the ESPs enhanced the performance of the individual and collective wells' deliverability because of their ability to large displacement and high net lift (Li *et al.*, 2018). As shown in Figure 6, ESP production rates across all the wells in the marginal field outperformed the production rate from the natural flow conditions. Figure 6 shows that the ESP system doubled the production rate from each well by over 120% increment per well for 13 years before the considerable decline. Also, this increases the productive life of the marginal field by ten years (Figure 7). Whereas the three wells produced at an average daily total rate of about 10000 stb/d before dropping to zero (0) stb/d after three years of consistent production, the use of the ESP system ensured a stable average cumulative production daily rate of about 14000 stb/d for eight years before declining to about 5400 stb/d after additional two years of production (Figure 7). This observation implies that ESPs deployment can reactivate otherwise dead natural flowing wells as commonly obtainable in marginal or mature fields.

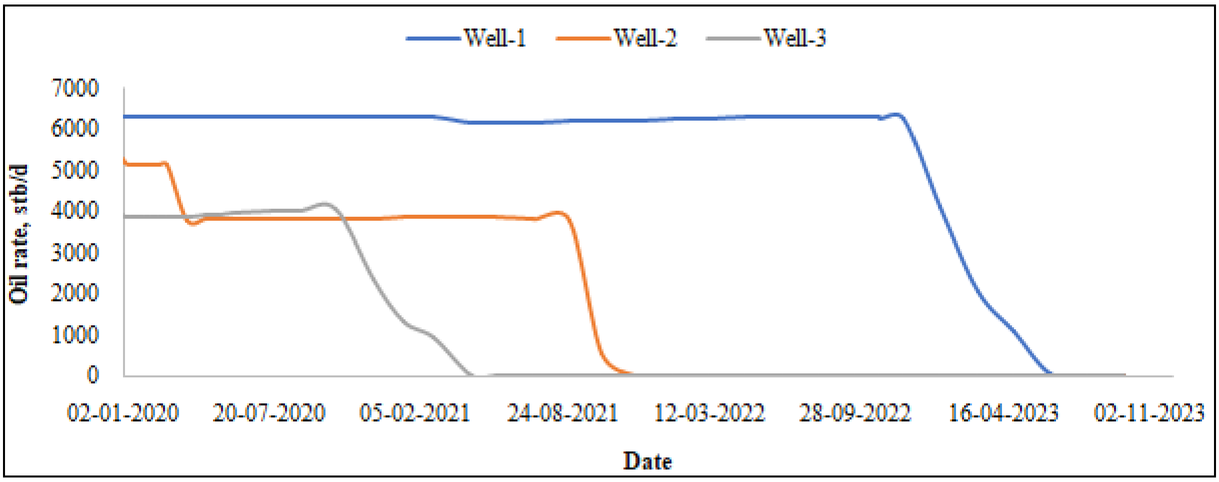

Figure 5: Well - 1, Well - 2, & Well - 3 production performance on natural flow

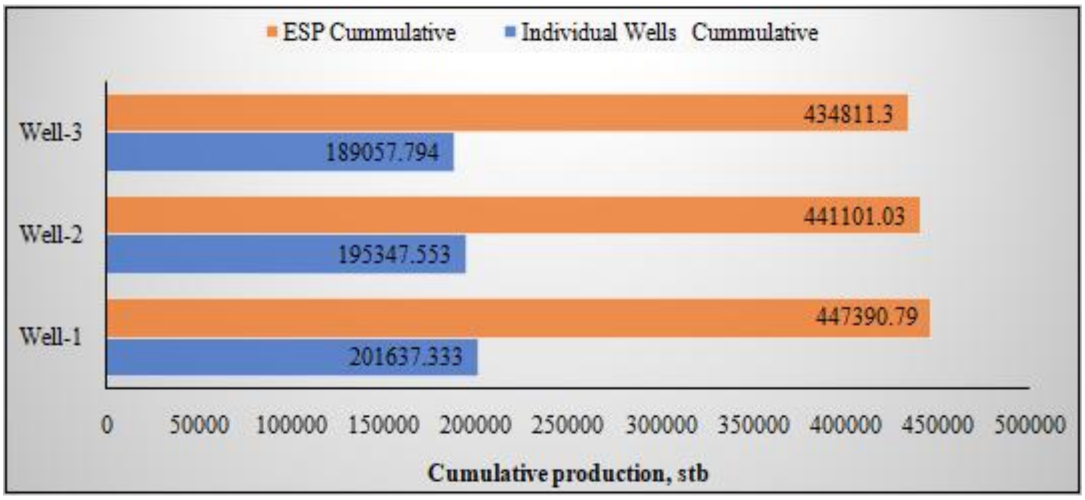

Figure 6: Comparing the wells' cumulative production of natural and ESP flows

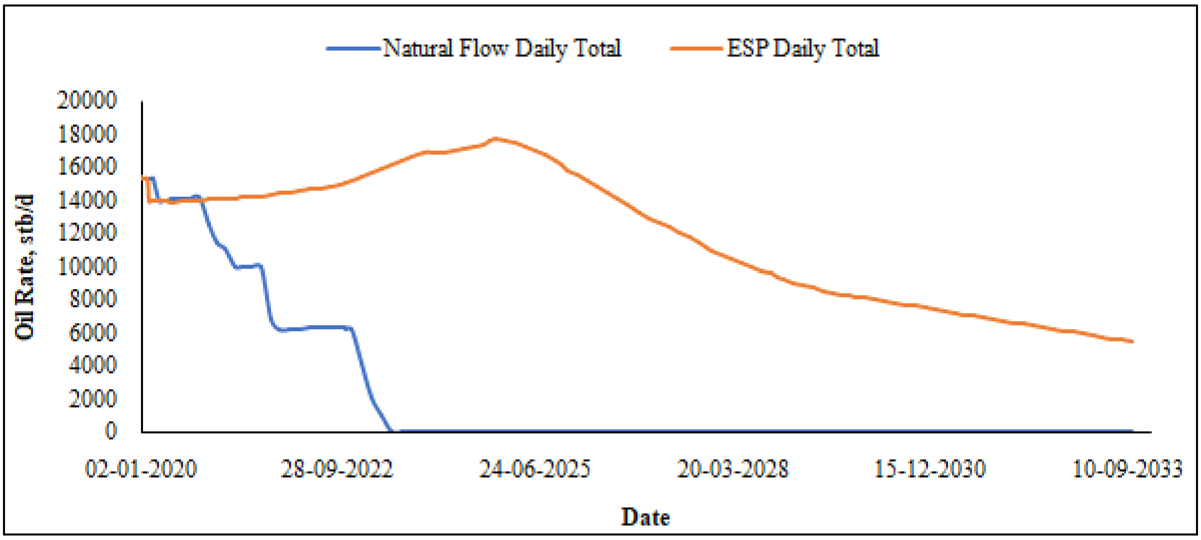

Figure 7: Comparing the field's cumulative production performance of natural and ESP flows

3.2 Sensitivity Analysis of ESP Operating Frequency on the Wells

Figures 8 through 10 are the sensitivity analysis results of Well - 1 through Well - 3 after ESP was deployed as the wells production - enhancing approach. Figure 8 indicates that the production rate of Well - 1 increased from 1373 stb/d to 2821 stb/d, 3276 stb/d, and 3750 stb/d at the operating frequency of 60 Hz, 70 Hz, and 80 Hz, respectively (as presented in Table 4). Interestingly, operating Well - 1 at 60 Hz, 70 Hz, and 80 Hz led to an increment of 1448 stb/d (about 51% oil increment), 1900 stb/d (about 58% oil increment), and 2377 stb/d (about 63% oil increment), respectively. Also, Figure 9 presents the result of the sensitivity analysis of Well - 2 after ESP deployment. From the figure, the production rate of the Well - 2 increased from 732 stb/d to 1325 stb/d at the operating frequency of 60 Hz, 1508 stb/d at 70 Hz, and 1686 stb/d at 80 Hz (Table 4). Again, operating the Well - 2 at 60 Hz resulted in increased oil production of 593 stb/d (about 45% oil increment), at 70 Hz will lead to an increment of 776 stb/d (about 52% oil increment), and at 80 Hz increment of 954 stb/d (about 57% oil increment) was obtained.

Table 4: Performance of the Wells with increasing ESP operating frequencies

Frequency (Hz)	Well - 1		Well - 2		Well - 3	
	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)
0	1373	2852.858	731.8819	2611.725	867.3052	2601.107
60	2821	2494.565	1325.175	2255.239	1092.821	2518.408
70	3273	2380.762	1507.802	2135.338	1256.009	2457.05
80	3750	2262.369	1686.198	2012.406	1420.389	2393.86

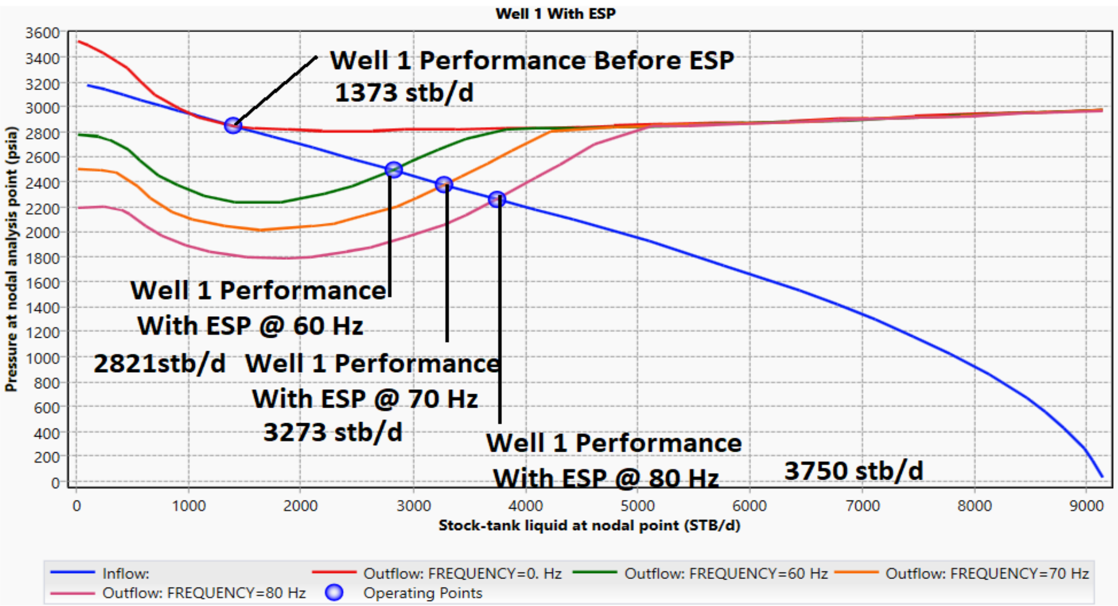

Figure 8: Impact of increasing ESP operating frequency on Well - 1

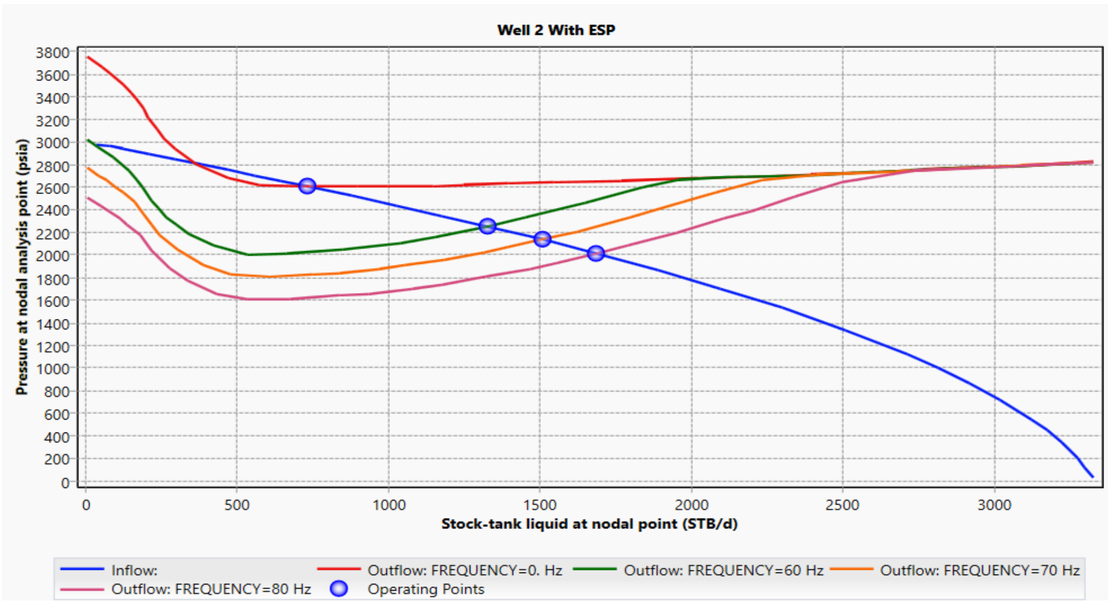

Figure 9: Impact of increasing ESP operating frequency on Well - 2

Figure 10 presents the performance of Well - 3 after ESP was implemented as an effective means of optimizing its production. From the figure, the production rate increased from 867 stb/d to 1093 stb/d at the operating frequency of 60 Hz, 1256 stb/d at 70 Hz and 1420 stb/d at 80 Hz (visible in Table 4). Again, operating Well - 3 at 60 Hz will lead to an increment of 226 stb/d (about 20% oil increment), an increment of 389 stb/d (about 31% oil increment) at 70 Hz, and an increment of 553 stb/d (about 39% oil increment) at 80 Hz.

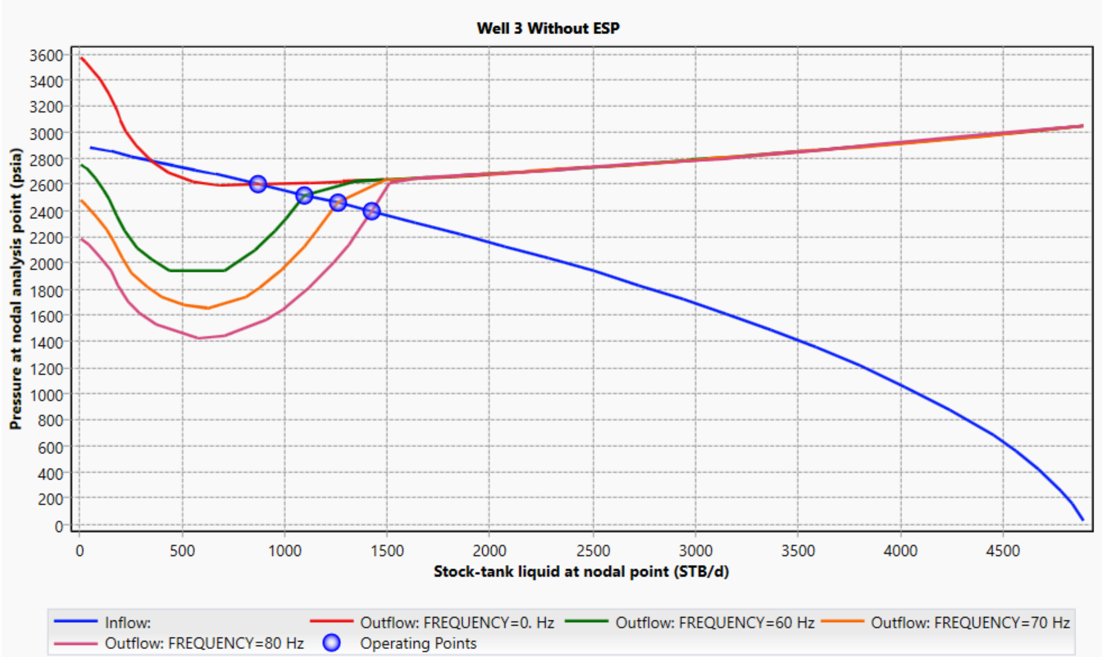

Figure 10: Impact of increasing ESP operating frequency on Well - 3

The advantage of using ESPs in oilfield development and application is their ability to adapt to the wellbore changing conditions and the surface capabilities of the gathering facilities. Meaning that the production rates and the field capacity can be altered with the help of variable speed drives as the need arises. According to Sharma and Glemmestad (2014), ESP frequency has a significant effect on the volume of oil produced from a field. Therefore, the frequency of ESPs in each well should be applied with sufficient accuracy. From Figures 8 through 10, the natural flow tended to decline over a period of 3 years, while the ESP system provided means of increasing the production rate by adjusting the frequencies of the ESP systems in all the wells. The production rates continuously increased as the frequency increased from 60Hz to 70Hz, and to 80Hz across all the wells. Hence, ESP has the potential to keep the marginal field productively afloat and competitive in the long run.

3.3 Sensitivity Analysis of Impact of Decreasing Reservoir Pressure on the ESP Wells

Figures 11 through 13 are results from the sensitivity analysis of the reservoir pressure that will affect the ESP performance on the wells (i. e., Well - 1 through Well - 3). In Figure 11, the ESP performance in Well - 1 diminished when reservoir pressure dropped below 2400 psi. Thus, the critical pressure below which Well - 1 will no longer produce oil is 2400 psi (as indicated in Table 5). Figure 12 depicts that the ESP will stop operating when reservoir pressure drops below 2200 psi. Therefore, the critical reservoir pressure for Well - 2 is 2200 psi (Table 5). Again, Figure 13 presents the sensitivity of Well - 3 with the reservoir pressure. The results indicate that the performance of ESP in Well - 3 will still be operating at 2000 psi with 780stb/d (Table 5).

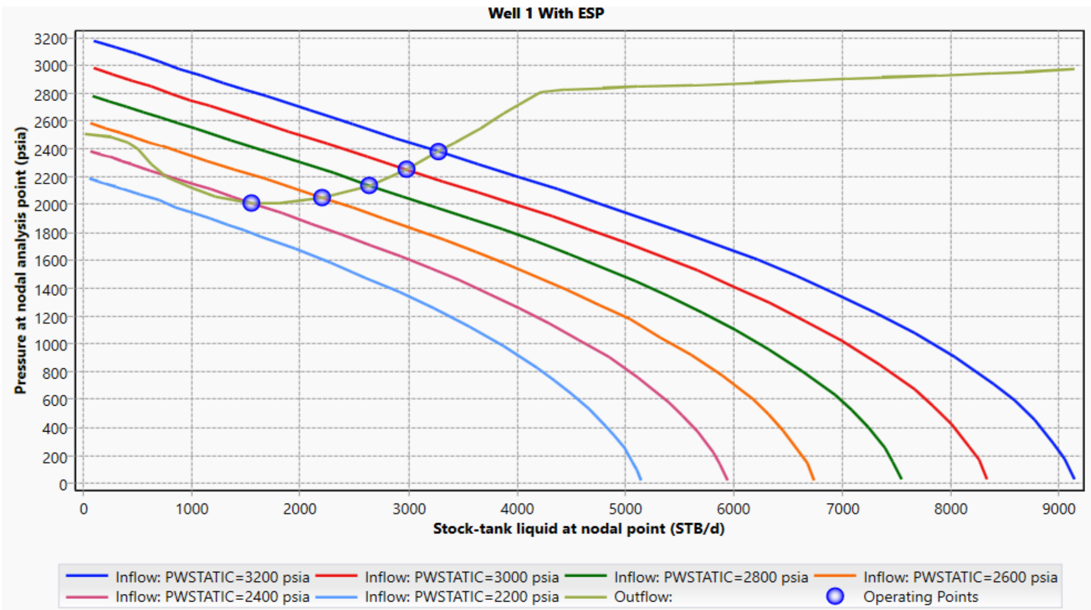

Figure 11: Impact of decreasing reservoir pressure on ESP of Well - 1

Table 5: Performance of the Wells with decreasing reservoir pressure on the ESP

Reservoir Pressure (psi)	Well - 1		Well - 2		Well - 3	
	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)
3200	3276.857	2380.786	- -	- -	- -	- -
3000	2975.988	2256.003	1507.766	2135.362	- -	- -
2900	- -	- -	- -	- -	1256.084	2457.022
2800	2633.938	2141.515	1341.434	2036.835	- -	- -
2700	- -	- -	- -	- -	1175.431	2279.017
2600	2195.626	2051.093	1158.952	1947.815	- -	- -
2500	- -	- -	- -	- -	1088.650	2110.089
2400	1549.350	2012.302	951.0453	1873.057	- -	- -
2300	- -	- -	- -	- -	988.479	1946.337
2200	- -	- -	702.649	1819.414	- -	- -
2100	- -	- -	- -	- -	860.997	1793.062
2000	0	2000	0	1819	779.702	1723.055

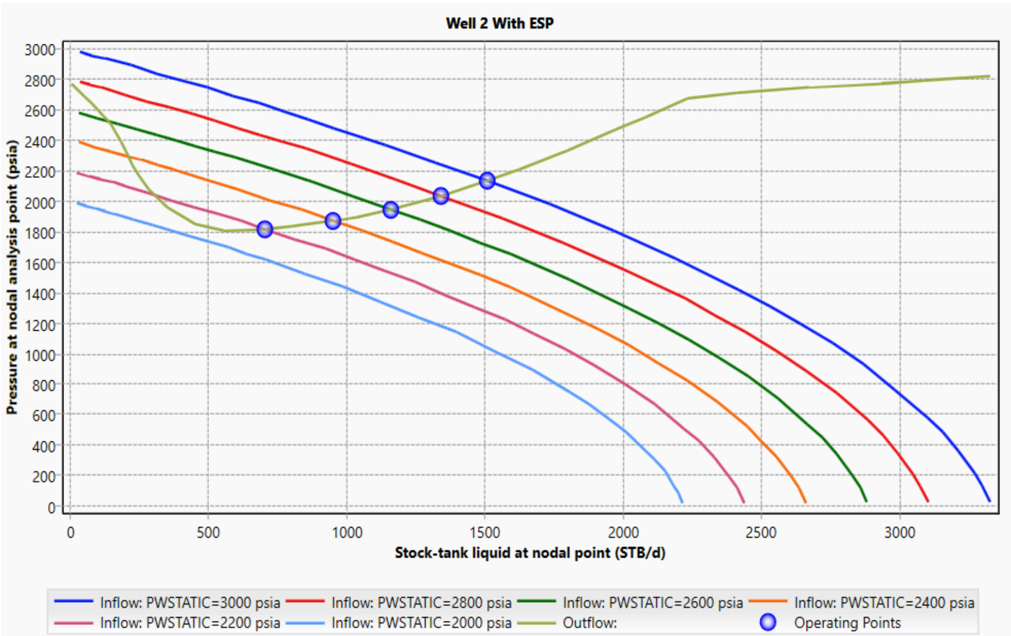

Figure 12: Impact of decreasing reservoir pressure on ESP of Well - 2

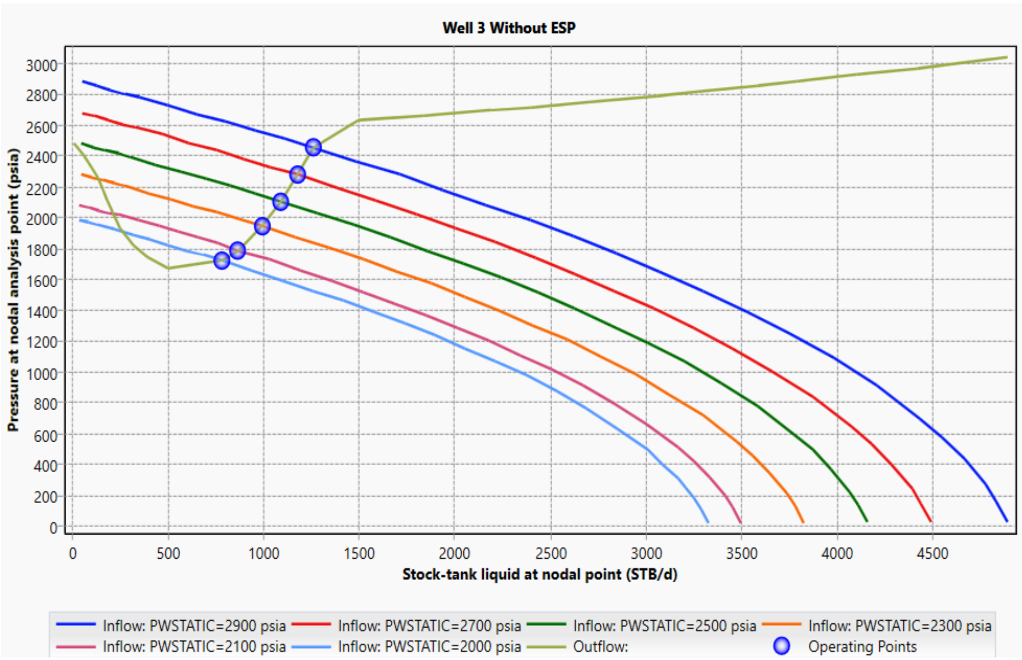

Figure 13: Impact of decreasing reservoir pressure on ESP of Well - 3

According to Li *et al*. (2018), ESP is selected over other artificial lift techniques in oilfield operations because of its versatility and ability to perform at varying conditions. Figures 11 through 13 show a declining production rate with decreasing reservoir pressure. Thus, the potential of the ESP to lift well fluids depends on the strength of the reservoir to deliver the fluid to the point on which the ESP design is placed. Agarwal *et al*. (2014) maintained that at some point in the life of the well, as the reservoir pressure decreases, both natural flow and ESP - assisted flow will cease. Again, Shen (2010) reported that when reservoir pressure declines to a certain level, maintaining the production rate with the conventional lift approach becomes nearly impossible. However, the ESP - assisted flow had better run and produced the wells' fluid more before ceasing to flow at about 1800 psia average bottom - hole pressures. The application of ESP in this respect is in line with the observations of Patron *et al*. (2017) that new strategies are necessary to continue to produce mature or marginal fields when the reservoir energy decreases following a long period of time that leads to a decline in production that no longer meets the economic criteria.

3.4 Sensitivity Analysis of Impact of Wellhead Pressure on the ESP Wells

Figures 14 through 16 present the results from the sensitivity of the wellhead pressure on the wells (i. e., Well - 1 through Well - 3) after ESP was used to optimize the wells' production potential. In Figure 14, an increase in the wellhead pressure affects the well's (Well - 1) ability to flow effectively (even with the ESP - assisted flow) to the surface as it opposes the bottom - hole flowing pressure. Also, the figure depicts that the higher the wellhead pressure, the lower the oil production rate, and the lower the wellhead pressure, the higher the oil production rate. This observation is attributed to the flow resistance imposed at the wellhead by the wellhead pressure (Okon*et al*., 2015). Again, the results indicate that at a wellhead pressure of 300 psi, 3352 stb/d of oil was produced and when the wellhead pressure was at 900 psi, 251 stb/d of oil was produced (Table 6). This implies that the wellhead pressure should be kept as low as possible to separator pressure to ensure that the ESP - assisted well flow is at its optimum. In Figures 15 and 16, the same trend for Well - 1 was observed for Well - 2 and Well - 3, that is, higher wellhead pressure results in a low oil production rate and lower wellhead pressure had a higher oil production rate. As visible in Table 6, for Well - 2, the wellhead pressure of 200 psi resulted in 1821 stb/d of oil production rate and 548 stb/d at a wellhead pressure of 1000 psi. Also, for Well - 3, the wellhead pressure of 200 psi produced an oil production rate of 1507 stb/d while the wellhead pressure of 800 psi dropped the oil production rate to 752 stb/d (Table 6).

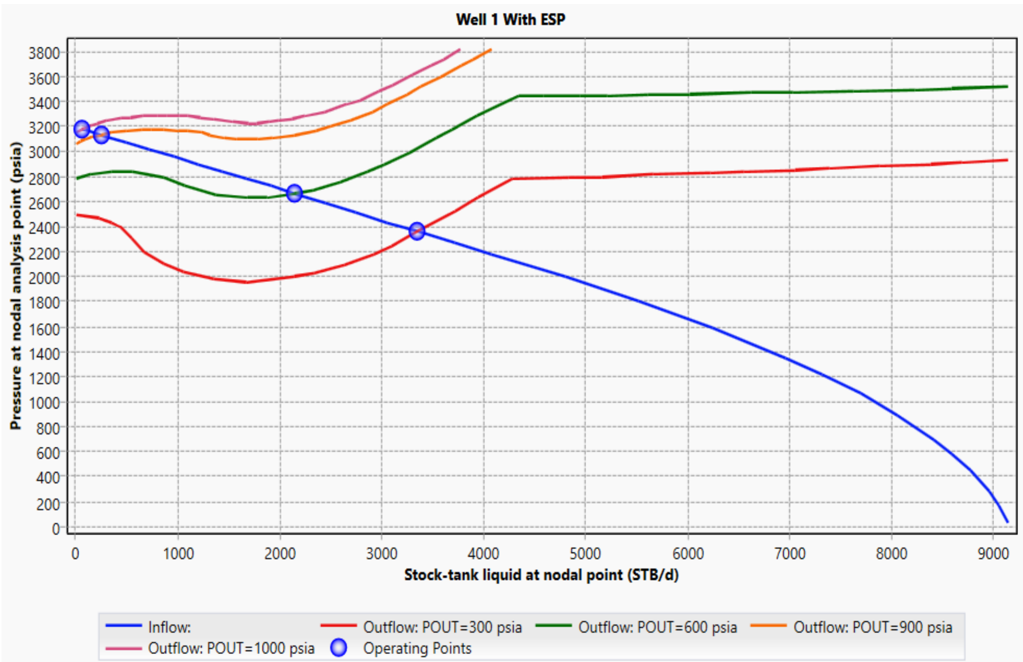

Figure 14: Impact of increasing wellhead pressure on ESP of Well - 1

Table 6: Performance of the Wells with increasing wellhead pressure on the ESP

Well Pressure (psi)	Well - 1		Well - 2		Well - 3	
	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)
200	- -	- -	1820.971	1915.163	1506.974	2359.985
300	3351.516	2362.121	- -	- -	- -	- -
400	- -	- -	1573.901	2090.504	1177.565	2486.71
600	2147.892	2663.027	1285.462	2280.596	1008.578	2549.576
800	- -	- -	915.649	2506.026	751.701	2642.616
900	251.455	3137.136	- -	- -	- -	- -
1000	64.039	3183.990	- -	- -	- -	- -

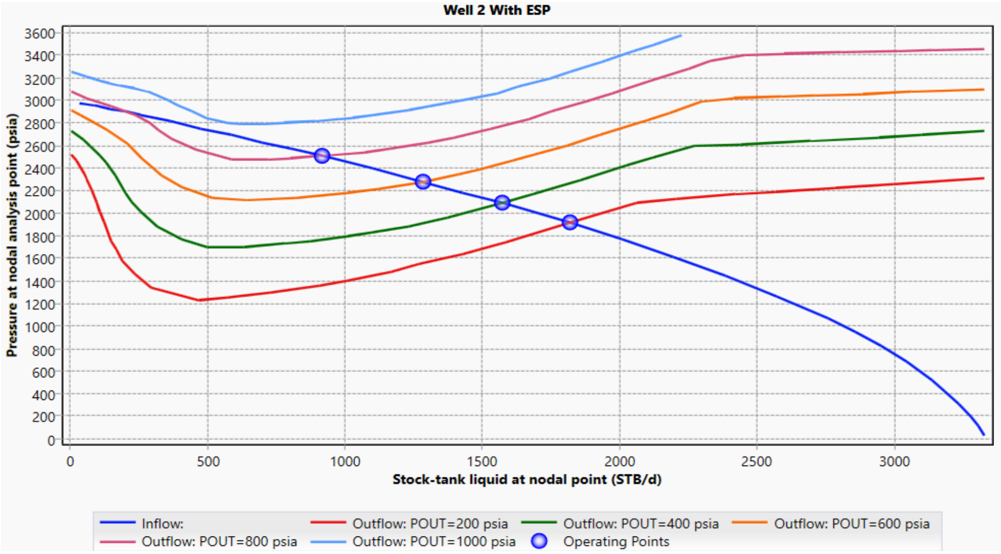

Figure 15: Impact of wellhead pressure on ESP of Well - 2

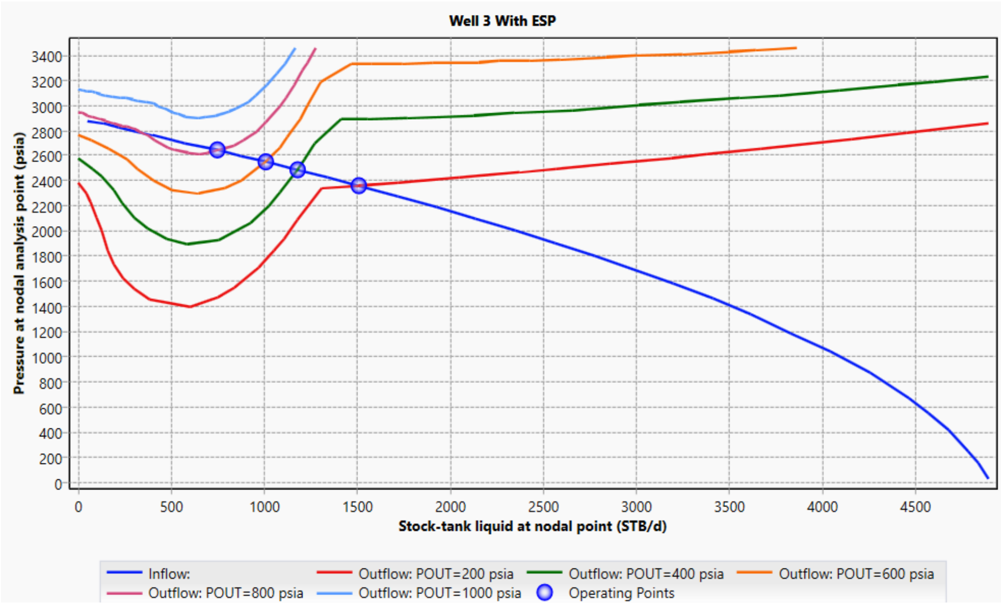

Figure 16: Impact of wellhead pressure on ESP of Well - 3

Backpressure from the surface facility increases the flow network of the field and the wellhead pressures of the individual wells. This development affects the deliverability of the wells. In some cases, it could lead to the wells becoming non - productive, especially when flowing on natural reservoir pressures. According to Sreenivasan *et al*. (2021), increasing wellhead pressure would reduce the production rate. Figures 14 through 16 show that production rates from the individual wells declined as the wellhead pressure increased. However, the wells continued to produce with ESPs assisting in lifting the wells' fluid to overcome the flow network backpressure created to maintain critical flow from the wells. The wells experienced a 20% reduction in production during the first 200 psi increase in wellhead pressures.

3.5 Sensitivity Analysis of Impact of Increasing Tubing Diameters on the ESP Wells

Figures 17 through 19 showed the sensitivity analysis of different tubing diameters on the EPS wells (i. e., Well - 1 through Well - 3) performance. From the figures, the tubing diameters impacted the increased oil production of the wells. In Figure 17 and Table 7, when the tubing diameter was 1 inch, the well (Well - 1) produced oil at 3310 stb/d. The increased well performance continued with 2 - , 3 - and 4 - inch tubing diameters at oil production rates of 3316 stb/d, 3328 stb/d, and 3334 stb/d, respectively. However, the oil production rates dropped at 5 - and 6 - inch tubing diameters to 3280 stb/d and 3200 stb/d, respectively (Table 7), after 3334 stb/d oil production rate was achieved with a 4 - inch tubing diameter. The import of this observation is that the 4 - inch tubing diameter is more effective for oil production in Well - 1 than other tubing sizes. On the other hand, Figure 18 and Table 7 depict the tubing sizes' impact on Well - 2 oil production rate performance. In the figure and table, the 1 - inch tubing diameter resulted in a low oil production rate of 367 stb/d. Interestingly, improved oil production rates were attended at 2 - through 6 - inch tubing diameters (Table 7). Again, the oil production rate at 5 - and 6 - inch (i. e., 1502 stb/d and 1307 stb/d) dropped when compared with the 4 - inch tubing size's oil production rate. Figure 19 presents the Well - 3 oil production rate performance. Thus, at a 1 - inch tubing diameter, the oil well was produced at 431 stb/d

(Table 7). At varying tubing diameters, the results showed that Well - 3 production performance increased with 2 - through 6 - inch tubing sizes, as visible in Table 7. However, the scenarios (i. e., dropped in oil production rate) experienced in Well - 1 and Well - 2 at 5 - and 6 - inch tubing diameters are applicable in Well - 3.

Table 7: Performance of the Well with increasing tubing diameters on ESP

Diameter	Well - 1		Well - 2		Well - 3	
(inches)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)
1	3309.555	2372.611	367.224	2811.102	431.339	2754.754
2	3316.349	2370.913	1266.709	2292.486	1159.960	2493.324
3	3328.478	2367.881	1507.143	2135.780	1256.649	2456.807
4	3333.845	2366.539	1544.681	2110.423	1272.898	2450.624
5	3280.333	2379.917	1502.362	2138.992	1230.268	2466.817
6	3200.679	2399.830	1307.115	2266.805	1167.291	2490.572

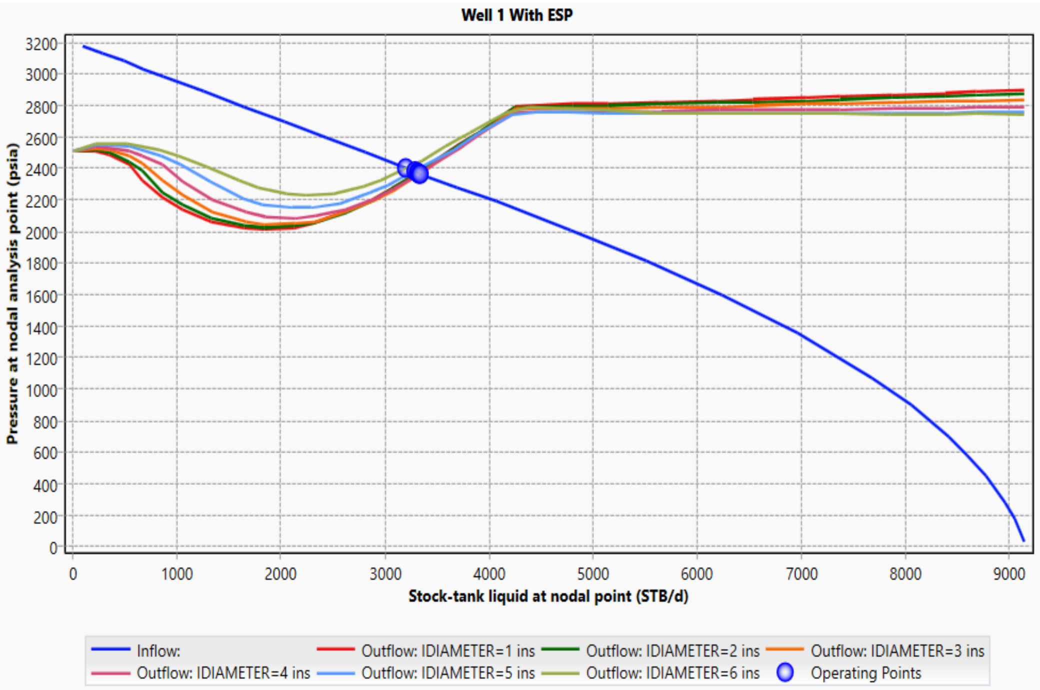

Figure 17: Impact of increasing tubing diameters on ESP of Well - 1

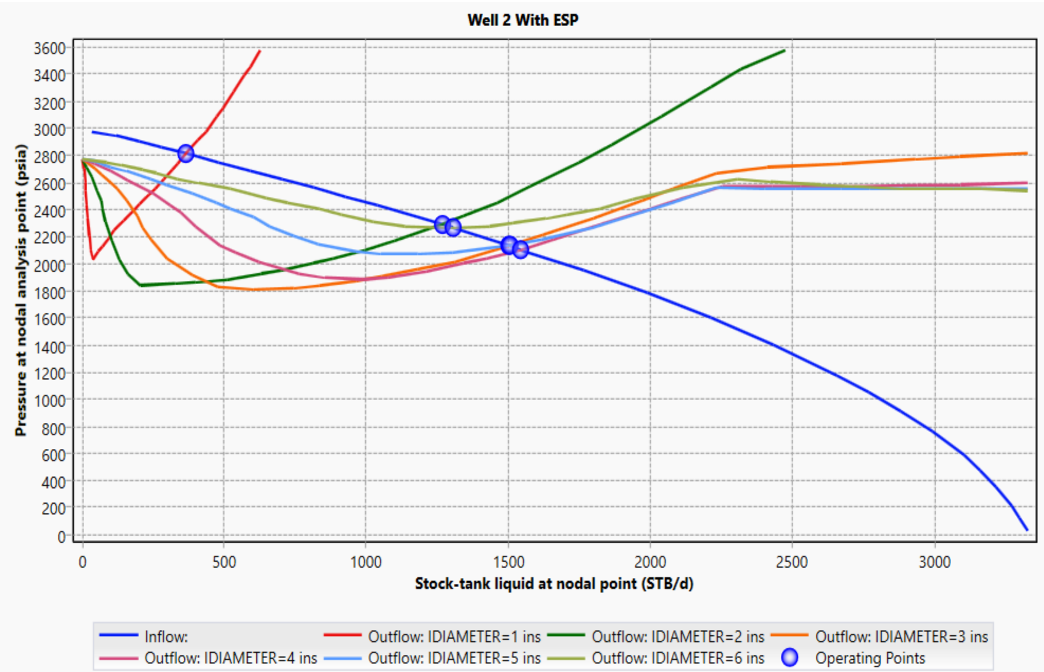

Figure 18: Impact of increasing tubing diameters on ESP of Well - 2

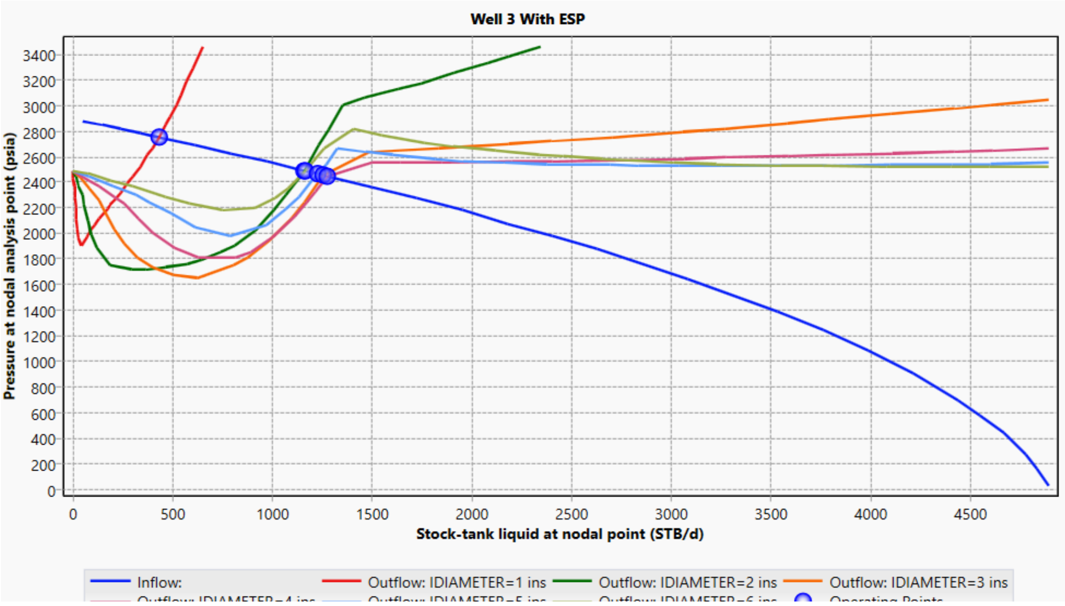

Figure 19: Impact of increasing tubing diameters on ESP of Well - 3

From the result of Figures 17 through 19, the tubing diameter of the wells' completion affects the production performance of the wells, though not linearly. The production rates increased as the diameter increased from 1 inch to 4 inches. However, there was a decline in rates across the wells as the tubing diameters increased further from 4 inches to 6 inches in all three wells (i. e., Well - 1 through Well - 3). The different tubing diameters also had varied impacts on the bottom - hole pressures of the wells. Hence, it is necessary to assess the effect of tubular sizes on the wells' deliverability and predict their production deliverability changes as the reservoir pressure decreases (Jansen, 2017). However, as with other varying constraining conditions, the ESP system continues fluid lifting in all the various tubular sizes to keep the marginal field productive even when it would have been otherwise on natural flow.

3.6 Sensitivity Analysis of Impact of Increasing Tubing Diameters on the ESP Wells

Figures 20 through 22 and Table 8 present the sensitivity analysis of the ESP wells (i. e., Well - 1 through Well - 3) production rates at varying water cuts. The results in Figures 20 through 22 and Table 8 indicate that the wells' production rate decreased as the water cut increased. At the limiting water cut (i. e., 90% water cut), the wells had oil production rates of 802 stb/d, 245 stb/d and 1145 stb/d for Well - 1, Well - 2, and Well - 3, respectively, with corresponding bottom - hole flowing pressure of 2999 psi, 2875 psi, and 2497 psi (Table 8).

Table 8: Performance of the Wells with increasing water - cut on the ESP

Water cut (%)	Well - 1		Well - 2		Well - 3	
	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)	Flowrate (stb/day)	BHP (psia)
50	3092.463	2426.884	- -	- -	- -	- -
60	2841.623	2489.594	1459.524	2167.584	1256.084	2457.022
70	2495.298	2576.176	1314.638	2261.991	1222.475	2469.768
80	1944.241	2713.94	1042.88	2430.513	1149.75	2497.153
90	802.4116	2999.397	245.1982	2875.089	995.2317	2554.484

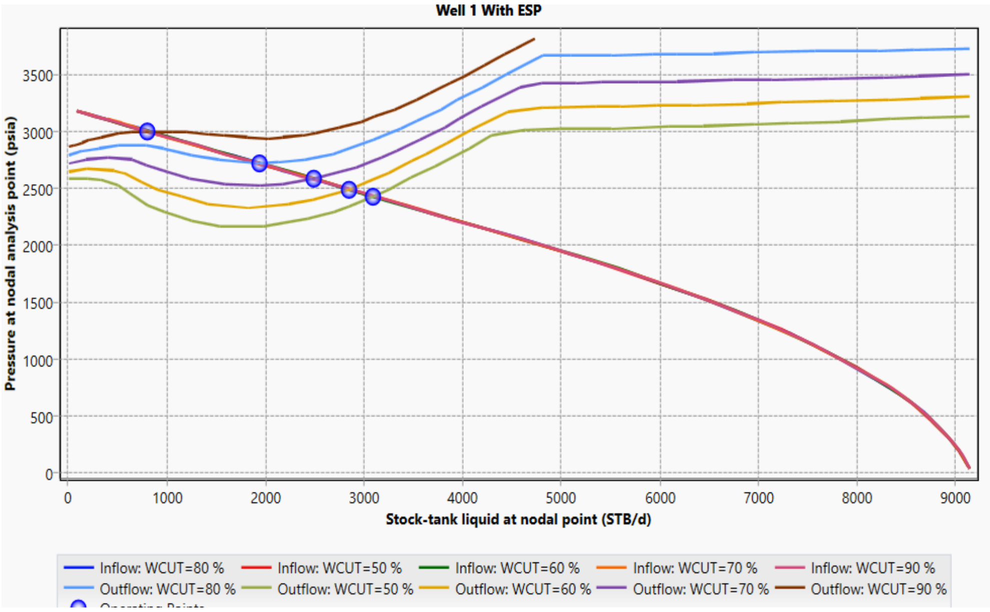

Figure 20: Impact of increasing water - cut on the ESP Well - 1

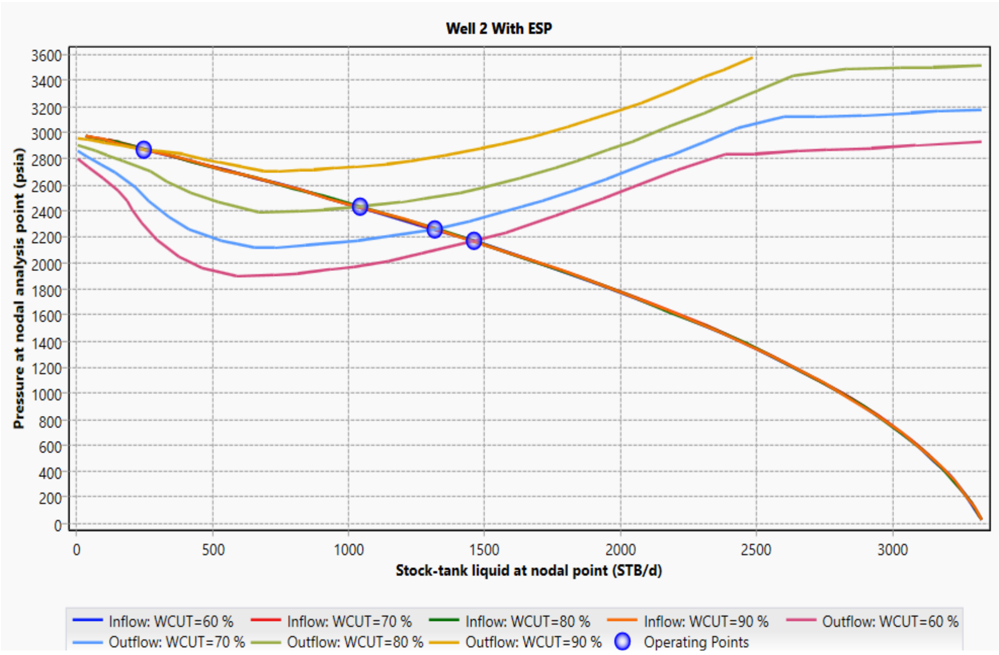

Figure 21: Impact of increasing water - cut on the ESP of Well - 2

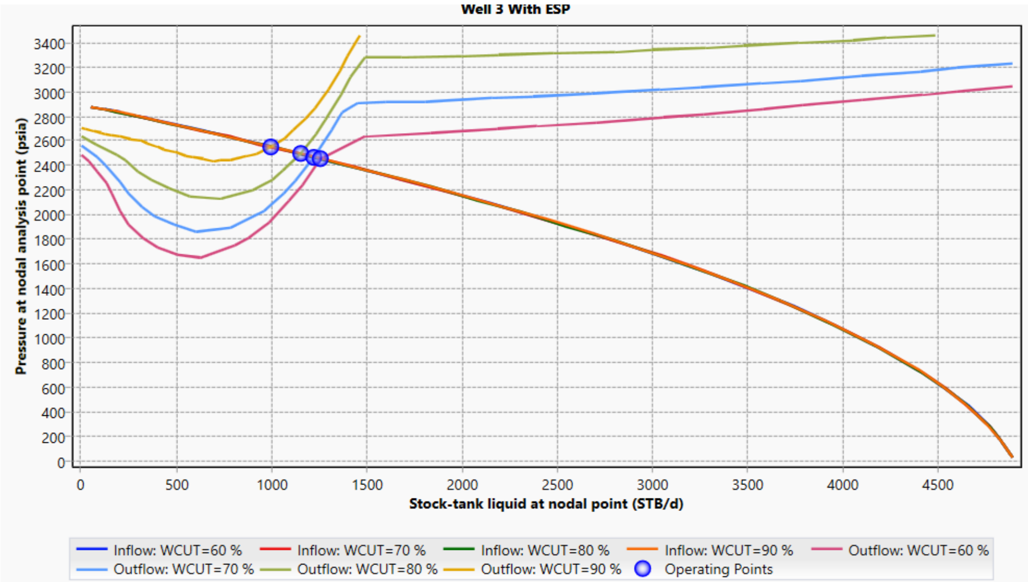

Figure 22: Impact of increasing water - cut on the ESP of Well - 3

Water cut affects the production performance of both natural and artificial lift - assisted wells (Sreenivasan *et al*., 2021). The wells could not continue production as the water cut increased from 20% upward on natural flow. Whereas the ESP - assisted wells flow (i. e., oil production) continued to decline to the water - cut percentage limit (90%), as seen in Figures 20 through 22. Water - cut has an inverse proportionality effect on the rate of oil produced (Sharma and Glemmestad, 2014), as seen across all three wells of the marginal field presented in Table 8. Increasing the production rate with higher water - cut provides a high cooling effect on the ESP motor that elongates the ESP run life and the overall field production life (Ergun *et al*., 2018). This scenario limits the capacity of the installed ESP unit, therefore increased water - cut should be considered during the designing phase of the unit.

4. Conclusion and Suggestions

Arguably, the ease of deployment, maintenance, flexibility of operation, reliability and high efficiency, and cost - effectiveness make the electric submersible pumping system the preferred artificial lift technology to redevelop and enhance the productive life of Niger Delta marginal fields. Implementation of electric submersible pumping systems can eliminate the need for infill drills to sustain marginal field production and reduce the cost and environmental impact of infill drilling. The ESP system increased the production capacity of each well in the field at an average rate of 120% of the natural flow capacity. Furthermore, the production life of the marginal oilfield was extended by ten years using ESPs to enhance the production of the field. These ensure the economic viability of operating the marginal oilfield in the Niger Delta.

From the sensitivity analysis of the ESP performance with potential field constraints, the oilfield potential can be managed in the long run through accurate and timely optimization of the ESP running frequency and completion tubular; even with an apparent decrease in reservoir pressure, increase in wellhead pressure and water - cut. The optimal frequency would be to run the ESP at 70 Hz at a wellhead pressure of 400 psi. The ESP system should be completed with a 4 - 1/2” tubular for reduced friction and optimal performance of the completion string, as the configuration has the potential to increase the field potential by 20 – 30% on the daily production of each well. Application of modern technologies to monitor the well systems to improve the marginal field production would lead to operational and production optimization in real - time. Also, the timely intervention of potential trips would ensure a consistent production rate and improved up - time of the field.

References

[1] Agarwal, A. K., Purwar, S. and Bravo, C. E. (2014.). Real - Time Diagnostic Analysis of Artificially Lifted Wells: A Smart Workflow Approach. *Intelligent Energy Conference and Exhibition*. Ultrecht, The Netherlands.: SOciety of Petroleum Engineers.

[2] Akpanika, O. I. and Udoh, F. D. (2008). *The Challenges of Marginal Fields Development in Nigeria. Journal of Ecology, Environment and Conservation*, 14 (2&3): 235 - 240.

[3] AlBallam, S., Karami, H. and Devegowda, D. (2023). A Hybrid Physical and Machine Learning Model to Diagnose Failures in Electrical Submersible Pumps. *SPE/IADC Middle East Drilling Technology Conference and Exhibition*. Abu Dhabi, UAE: Society of Petroleum Engineers.

[4] Arora, E. (2022). Marginal Field Development: Evaluation of Offshore Developments. *Offshore Technology Conference Asia*. Kuala Lumpur. Malaysia.: Society of Petroleum Engineers.

[5] Babadagli, T. (2005). Maature Field Development - A Review. *Europe/EAGE Annual Conference*. Madrid, Spain.: Society of Petroleum Engineers.

[6] Bertomeu, F., Hirschfeldt, M., Deigado, P. and Lobato - Barradas, G. (2015). Marginal Wells Inside Brownfields a High Profitability Business. *SPE Artificial Lift Conference - Latin America and Caribbean*. Bahia, Brazil: Society of Petroleum Engineers.

[7] Dagogo O., Iledare W., and Humphrey E. (2018). Economic Viability of Infil Drilling Program for Marginal Oil Field Development: A Case Study of Sango Field in Nigeria. *Nigeria Annual International Conference and Exhibition.* Lagos: Society of Petroleum Engineers.

[8] Ergun, E., Sahin, M. O. and Ercelebi, A. E. (2018). The Evaluation and Optimization of ESP Motor Service Life: A Statistical Study for Last 3 Decades for Adiyaman Fields, Turkey. *Middle East Artificial Lift Conference and Exhibition.* Manama, Bahrain.: Society of Petroleum Engineers.

[9] Faseemo, O. Massot, N., Healy, W. and Owah, E. (2009). Multidisciplinary Approach to Optimising Hydrocarbon Recovery From Conventional Offshore Nigeria: OML100 Case Study. *Nigeria Annual International Conference and Exhibition.* Abuja, Nigeria: Society of Petroleum Engineers.

[10] Hassan, S.; Hassaballah, H. and Gad, K. (2001). An Integrated Approach to Marginal Field Development: Case History From the Gulf of Suez. *Offshore Mediterranean Conference and Exhibition.* Ravenna, Italy.: Society of Petroleum Engineers.

[11] Idachaba, F. E. and Wokoma, E. (2017). Development of a SOlar - ESP Based Wellhead System for Remote Wellhead Operations in Marginal Oilfields. *SPE Annual Technical Conference and Exhibition,.* San Antonio, Texas: SOciety of Petroleum Engineers.

[12] Jansen, J. D. (2017). *Chapter 8: Well Performance.* Houston, Texas.: Society of Petroleum Engineers.

[13] Krukrubo, G. J. (2013). Infil Drilling Using Simulation and Cross Function Integration - Ubit Field Example. *International Petroleum Technology Conference.* Beijing: SOciety of Petroleum Engineers.

[14] Li, L., Hua, C. and Xu, X. (2018). Condition Monitoring and Fault Diagnosis of Electric Submersible Pump Based on Wellhead Electrical Parameters and Production Parameters. *Systems Science & Control Engineering.*, *6*, 253 - 261.

[15] Okon, A. N. and Appah, D. (2018). Water Coning Prediction: An Evaluation of Horizontal Well Correlations. *Engineering and Applied Sciences Journal*, 3 (1): 21 - 28. https: //doi. org/10.11648/j. eas.20183

[16] Okon, A. N., Olagunju, D. T. and Akpabio, J. U. (2017). Water Coning Control: A Comparison of Downhole Water Sink and Downhole Water Loop Technologies. *Journal of Scientific and Engineering Research*, 4 (12): 137 - 148.

[17] Okon, A. N., Udoh, F. D. and Appah, D. (2015). Empirical Wellhead Pressure - Production Rate Correlations for Niger Delta Oil Wells. Paper presented at the Society of Petroleum Engineers (SPE), Nigeria Council 39th Nigeria Annual International Conference and Exhibition, Eko Hotel and Suite, Lagos, August 4 - 6, 2015. http: //dx. doi. org/10.2118/178303 - M

[18] Oyewole, P. (2016). Artificial Lift Selection STrategy to Maximize Unconventional Oil and Gas Assets Value. *SPE North America Artificial Lift Conference and Exhibition.* Woodlands, Texas.: Society of Petroleum Engineers.

[19] Patron K., Villarreal P. and Loen, J. (2017). Case Studies of Optimizing the Artificial Lift Strategy for Reactivating Abandoned Wells in a Mature Field. *Annual Technical Conference and Exhibition.* San Anthonio, Texas.: Society of Petroleum Engineers.

[20] Sharma, R., and Glemmestad, B. (2014, August). Uncertainty and Sensitivity Analysis for a Model of an Electric Submersible Pump Lifted Oil Field. *International Journal of Modeling and Optimization.*, *4* (4), 278 - 286.

[21] Shen, J. (2010). Application of Composite Jet - Rod Pumping System in a Deep Heavy - Oil Field in Tarim China. *Annual Technical Conference and Exhibition.* Florence, Italy.: SOciety of Petroleum Engineers.

[22] Sreenivasan, H., Krishna, S., Patel, M., Bhatia, P. and Vij, R. K. (2021). Influence of Wellhead Pressure and Water Cut in the Optimization of Oil Production From Gas Lifted Wells. *Petroleum Research.*

[23] Tayyab, I., Farooq, U. M., Ahmed, Q. I., Rehman, I. and Azam, Q. S. (2016). Combination of Foam Assisted Lift and Gas Lift (FAGL) to De - Liqyuefy Gas Wells. *SPE/IADC Middle East Drilling Technology Conference and Exhibition.* Abu Dhabi, UAE.: Society of Petroleum Engineers.

[24] Zalavadia H., Singh P., Sinha U. and Sankaran S. (2023). Improving Artificial Lift Timing, Selection, and Operations Strategy Using a Physics Informed Data - Driven Method. *Unconventional Resources Technology Conference.* Denver, USA: Society of Petroleum Engineers.

Author Profile

Torty C Kalu-Ulu, is a Lead Petroleum Engineers and currently a PhD student of Petroleum Engineering in the Department of Chemical and Petroleum Engineering, Faculty of Engineering, University of Uyo, Nigeria. He holds an HND in Mechanical Production Engineering Technology, a BEng. and MSc. degrees in Petroleum Engineering, a PGD and PhD in Business Administration. His research interests are in Production engineering, Artificial Lift application and optimization, Sustainable Energy and Circular Economy

Anietie N. Okon, is a Senior Lecturer in the Department of Chemical and Petroleum Engineering, Faculty of Engineering, University of Uyo, Nigeria. He obtained his BEng. and PhD degrees from the University of Uyo and his MSc. from the Norwegian University of Science and Technology (NTNU), Norway. His research interests are in reservoir engineering, mathematical and artificial intelligence models development, and drilling fluid technology.

Dulu Appah is a Nigerian engineering educator., lives to most willingly offer his professional services to many universities in Nigeria, Germany and Ghana. He is currently the Director, Institute of Petroleum Studies, University of Port Harcourt. Achievements include research in sand control in oil-wells; research in well stimulation and fluid flow in porous media. Humboldt scholar, Institute Petroleum, Claushal, Germany, 1999-2002. Research Interest: Aerated Wellbore Sand Cleanout, Cement Slurry Design for HP/HT Wells, Fines Migration, Produced Water Management, Hydrate/Emulsion Control, and Artificial Lift Optimization.