# MAXIMZING OIL RECOVERY IN A MARGINAL OILFIELD: NIGER DELTA CASE STUDY

**Abstract**

Marginal field development and production are often abandoned by operators because of finding reliable and available equipment and services to enable the field to be developed. These challenges make it difficult to economically produce such fields. This research demonstrates the use of industry-based simulators (PIPESIM, ECLIPSE and PETREL) to design well completion model, Electrical Submersible Pump (ESP). model, simulate, and evaluate the performance of ESP on a typical marginal oilfield. The main objective of this study is to effectively optimize oil production from marginal fields in the Niger Delta using Electrical Submersible Pump (ESP). ECLIPSE software was used for the reservoir description. PIPESIM was used to design the artificial lift system (ESP) forfive oil wells and PETREL was used to integrate the whole system for effective production optimization. The performance of ESP wells was simulated and compared with the naturally flowing wells. The results obtained from the production forecast showed that the ESP wells gave superior oil production when compared to natural flowing wells. From the simulation results, it was observed that the cumulative oil recovery without ESP was 33,684,736 stb while that recovered with ESP was 87,751,136 stb (about 261% oil increment). The findings of this study will enable petroleum engineers to design ESP systems and well completion that would effectively optimize oil production from marginal fields in the Niger Delta. Furthermore, the findings of the study will offer new and exciting ways to process and transform abandon oilfields into productive marginal oilfields.

Keywords: Marginal oilfield, ESP, Niger Deta, PIPESIM, ECLIPSE and PETREL

## 1. INTRODUCTION

The marginal field has been defined by many researchers in different lights. Among the many definitions, a marginal field is an oilfield that may not be able to produce enough positive income to make the field worth developing at a particular time and may not have been tapped for a long time (Raj et al., 2014). Francis and Wokoma (2017) have 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 development potent considerable potential for the global hydrocarbon output (Energyhub, 2021), however, the development of marginal oil and gas fields is lagging due to several challenges despite respective government policy initiatives (Humphrey and Dosunmu, 2017).

The challenges of increasing hydrocarbon production are not uncommon in the oil and gas industry and field development for both green and brownfields. Be it a naturally flowing well or an artificially lifted hydrocarbon well, there are challenges associated with efforts to maintain or sustain a desired production target. These challenges affect the life span of the well-completion system. Reservoir pressure decline over the life of the field could cause an increase in produced water-cut accompanied by a decrease in the gas ration. This combination could cause the well to stop producing the required target to the surface. The decline in production at the desired rate will mean the inability to deliver fluid to the gathering facility through the production pipelines (Elshan, 2013). Sinulingga and Yananto, (2017) in their study proposed a low capital cost and low maintenance cost pipeline technology as a means to economically develop, produce, and maintain a marginal field producing with high $CO_2$ content through a 6.3 km 8-inch pipeline.

Marginal field development and production are often abandoned by operators because of the complexities posed by the challenges identified below:

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 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.

These challenges make it difficult to economically produce such fields. The number one challenge identified by Raj *et al*., (2014) is the issue of 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 the marginal fields (Ayuk, 2021; Kahali *et al*., 1991).

One sure way to avoid hydrocarbon production decline and completion equipment failure is by optimization (Dholkawala *et al*., 2010). It is therefore 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 cost-effective. According to Onwuemene, (2021), the technical approach to re-enter and produce a marginal field must be cost-effective with comparatively reduced capital outlay, and reduced risk exposure. Hence, this research work will study the deployment of Electric submersible pumping (ESP) systems as a cost-effective means to optimize marginal field production. The study will advance to identify the limitations of the preferred production option and how best to manage a marginal field development using the proffered option to sustain the production output of a typical marginal field in the Niger Delta.

## 2. METHODOLOGY

### 2.1 Research Design

This research used commercial simulators (PIPESIM, INTERSECT and PETREL) to design well completion model, ESP model, simulate, and evaluate the performance of ESP on a marginal oilfield in the Niger Delta. Five oil wells were simulated and their production performance were evaluated. The wells' production outputs were optimized using ESP. INTERSECT software was used for the reservoir description. PIPESIM was used to design the artificial lift system (ESP) for the wells and PETREL was used to integrate the whole system for production optimization. It involved an outline description of different methods applied and the procedures undertaken to effectively arrive at the objectives of the study. To analyze the economic viability of this study, economic indices such as Net Present Value (NPV), Profitability Index (PI) and Internal Rate of Return (IRR) were employed to assess the profitability of the ESP technique. The datasets used in this study were obtained from a marginal oilfield operating in the Niger Delta (Tables 1 and 2).
Two approaches were followed to achieve the objectives of the thesis. Both approaches highlighted the material components that affect ESP system design, selection, deployment, performance, durability and intervention. The two methods used in this study are:
I. ESP System Modelling Approach
II. Economic analysis Approach

### 2.2 Case Study Field Data and Definitions

The field operated by ABC company is located about 20Km from the nearest gathering facility. The field reservoir is an unconsolidated sandstone formation type bearing crude API range of 21 to 36. The five wells located in the marginal field were drilled and produced effectively delivering to the nearest gathering facility until the water cut increase resulting in heavy decline in the production from these wells. The study will provide the basis for the design for the selected completion system and engineering design. The downhole completion equipment and surface equipment specification and selection will be based on the available data and information in table 1. with assumptions based on industry guidelines.

**Table 1: Fluid and Reservoir Data**

| **Parameters** | **Well 1** | **Well 2** | **Well 3** | **Well 4** | **Well 5** |
|---|---|---|---|---|---|
| GOR | 800 scf/STB | 392 scf/STB | 900 scf/STB | 760 scf/STB | 570 scf/STB |
| API | 35 | 37.7 | 40 | 42 | 39 |
| Water Gravity | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| Gas Gravity | 0.9 | 1.1 | 0.8 | 0.87 | 0.75 |
| Mole % of H2S | 0 | 0 | 0 | 0 | 0 |
| Mole % of CO2 | 0 | 0 | 0 | 0 | 0 |
| Mole % of N2 | 0 | 0 | 0 | 0 | 0 |
| Oil Density | 41 lb/ft3 | 46 lb/ft3 | 50 lb/ft3 | 49 lb/ft3 | 48 lb/ft3 |
| Oil FVF | 1.3 RB/STB | 1.3 RB/STB | 1.5 RB/STB | 1.4 RB/STB | 1.1 RB/STB |
| Oil Viscosity | 0.6 Cp | 0.6 Cp | 0.6 Cp | 0.6 Cp | 0.6 Cp |
| Oil Compress | 1/psi | 1/psi | 1/psi | 1/psi | 1/psi |
| Gas Density | 14 lb/ft3 | 12.9 lb/ft3 | 13.9 lb/ft3 | 11 lb/ft3 | 12.2 lb/ft3 |
| Gas Viscosity | 0.3 Cp | 0.2 Cp | 0.21 Cp | 0.31 Cp | 0.4 Cp |
| Gas FVF | 0.006 ft3/scf | 0.006 ft3/scf | 0.006 ft3/scf | 0.006 ft3/scf | 0.006 ft3/scf |
| Water Density | 65 lb/ft3 | 64 lb/ft3 | 64 lb/ft3 | 64 lb/ft3 | 64 lb/ft3 |
| Water Viscosity | 0.4 Cp | 0.4 Cp | 0.4 Cp | 0.4 Cp | 0.4 Cp |
| Water FVF | 1.000 RB/STB | 1.01 RB/STB | 1.02 RB/STB | 1.02 RB/STB | 1.4 RB/STB |
| Water Salinity | 80000 ppm | 80000 ppm | 80000 ppm | 80000 ppm | 80000 ppm |
| Overall Heat | 3 BTU/H/FT2/F | 3BTU/H/FT2/F | 3BTU/H/FT2/F | 3BTU/H/FT2/F | 3BTU/H/FT2/F |
| Cp Oil | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F |
| CP Gas | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F | 0.5 BTU/lb/F |
| Reservoir Pressure | 3200 psi | 3000 psi | 2900 psi | 3100 psi | 3300 psi |
| Wellhead Pressure | 300 psi | 450 psi | 302 psi | 303 psi | 304 psi |
| Reservoir Temperature | 150 degF | 160 degF | 155 degF | 155 degF | 170 degF |
| Water cut | 50% | 55% | 60% | 60% | 58% |
| Reservoir Permeability | 600md | 600 md | 600 md | 600 md | 600 md |
| Reservoir Thickness | 100 ft | 110 ft | 90 ft | 90 ft | 112 ft |
| Drainage Area | 250 acres | 250 acres | 250 acres | 250 acres | 250 acres |
| Wellbore Radius | 0.5 ft | 0.5 ft | 0.5 ft | 0.5 ft | 0.5 ft |
| Skin | 5 | 7 | 3 | 3 | 3 |
| Porosity | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction |
| Connate Water Sat | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction | 0.3 Fraction |
| Original Oil in Place | 2000 MMSTB | 2000 MMSTB | 2000 MMSTB | 2000 MMSTB | 2000 MMSTB |
| Initial Gas Cap | 0 | 0 | 0 | 0 | 0 |



**Table 2: Downhole Data**

| | |
|---|---|
| **Casing Data** | |
| Casing ID | 8.681 inches |
| Casing wall thickness | 0.472 inches |
| Casing bottom MD | 9100 ft |
| Casing roughness | 0.001 inches |
| | |
| **Tubing Data** | |
| Tubing ID | 3.476 inches |
| Tubing wall thickness | 0.262 inches |
| Tubing bottom MD | 8550 ft |
| Tubing roughness | 0.001 inches |
| | |
| **Downhole Equipment** | |
| Packer depth | 8500 ft |
| | |
| **Heat Transfer Data** | |
| Heat transfer coefficient | 2 Btu/h/°F/ft$^2$ |
| Wellhead ambient temperature | 30 °F |
| | |
| **Completion Data** | |
| Mid-perforation depth | 8800 feet |
| IPR model | Well PI |
| Reservoir Pressure | 4000 psi |
| Reservoir Temperature | 200 °F |
| | |
| **Fluid Model** | |
| GOR | 2800 scf/stb |
| Water cut | 40 % |
| Gas Specific Gravity | 0.75 |
| Water Specific Gravity | 1 |
| API | 39 |
| Viscosity | 1.34 cp |
| | |



**2.3 Nodal Analysis Software (PIPESIM)**

A Nodal Analysis software application (PIPESIM 2019 VERSION) was used in this study to calibrate and conduct sensitivity analysis. The design and simulation were done using PIPESIM Software. In this study, PIPESIM was used to build a well model, design a perforation and evaluate it performance. The PIPESIM simulator provides a new and unique well-centric workspace for building the well model. The interactive well schematic appears on the left, enabling us to drag and drop well components such as tubing and casing (Figure1).Wedraggedacasinganddroppeditaroundthewell-headandselectedthedetailedtubularmodel.Weentered itsdepthto9000feetandchangedthedefaultcasingbybrowsingthecataloguetoselecta7-in,L-80,35 pound per foot casing. We changed the borehole diameter to 8.5 in and accepted the default cementinformation. We added a tubing by adding a new row in the tubing section. We changed the tubing depthto8800feetanddirectlyentertheinformationfor2-⅞inchtubing,aninsidediameterof2.441in,wall thickness of 0.217 in and default roughness of 0.001 in.

**2.4 Modeling Packer and Perforation**

We launched the packer and perforation design task and enter the packer depth of 8798 feet and completion target depth of 8900 feet. The brine-filled wellbore and borehole diameter have been populated correctly from the well model. In the tubular section, the pipes that are present at the completion depth of 9000 to 9100 feet have been automatically populated (Figure 2). The task has correctly installed the completion and populated some of the properties such as the reservoir pressure, damaged zone thickness and the perforation parameters such as shot density, diameter, length and phase angle. The installed completion has also set the Darcy IPR model which supports the skin calculations required for well productivity. We entered the following missing reservoir properties: temperature of $180^{0}$F, reservoir thickness of 30 feet and reservoir permeability of 600 mD. We entered the following missing skin information: damaged zone to unaltered reservoir permeability ratio of 0.8, perforated interval ratio of 0.9, permeability anisotropy ratio of 0.1, crushed zone to unaltered reservoir permeability ratio of 0.9 and crushed zone thickness of 0.25 inch.

**2.5 Modeling Fluid Model**

We defined a black oil fluid on the fluid model subtab with the following properties: a water cut of 20%, gas - oil ratio of 2800 SCF/STB, gas specific gravity of 0.75 and API gravity of 39. We leave all other fields set to their default values. It is important to note that these calculated skin values are for the completion installed with the 4.72 in pure gun system. It is important to calculate the skin values for all the selected gun systems to determine whether the 4.72 in pure gun system is still the best option from a productivity perspective. This requires rerunning the perforation design task. the well model currently has an installed completion with the Darcy model defined with the various skin elements. The task calculated the skin components for each gun system using the perforation lengths and diameters simulated in the task, as well as the other skin input parameters in the well model. The results tab is now updated to show the productivity results in addition to the previous perforation results. It is cleared that the already installed completion associated with the 4.72 in pure gun system is still the better option because it has a lower skin.

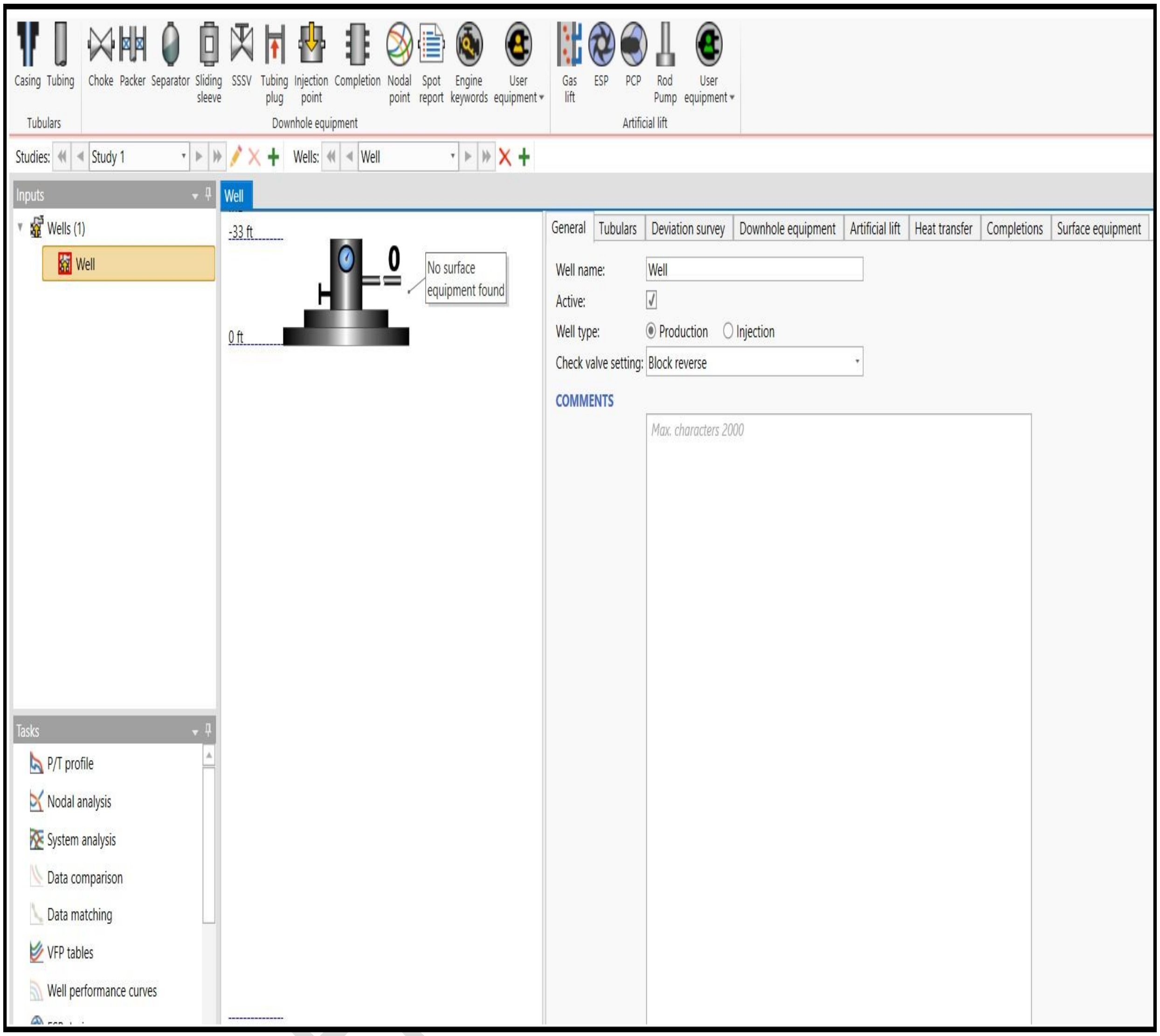


**Figure1**: Interactive Well Schematic in PIPESIM

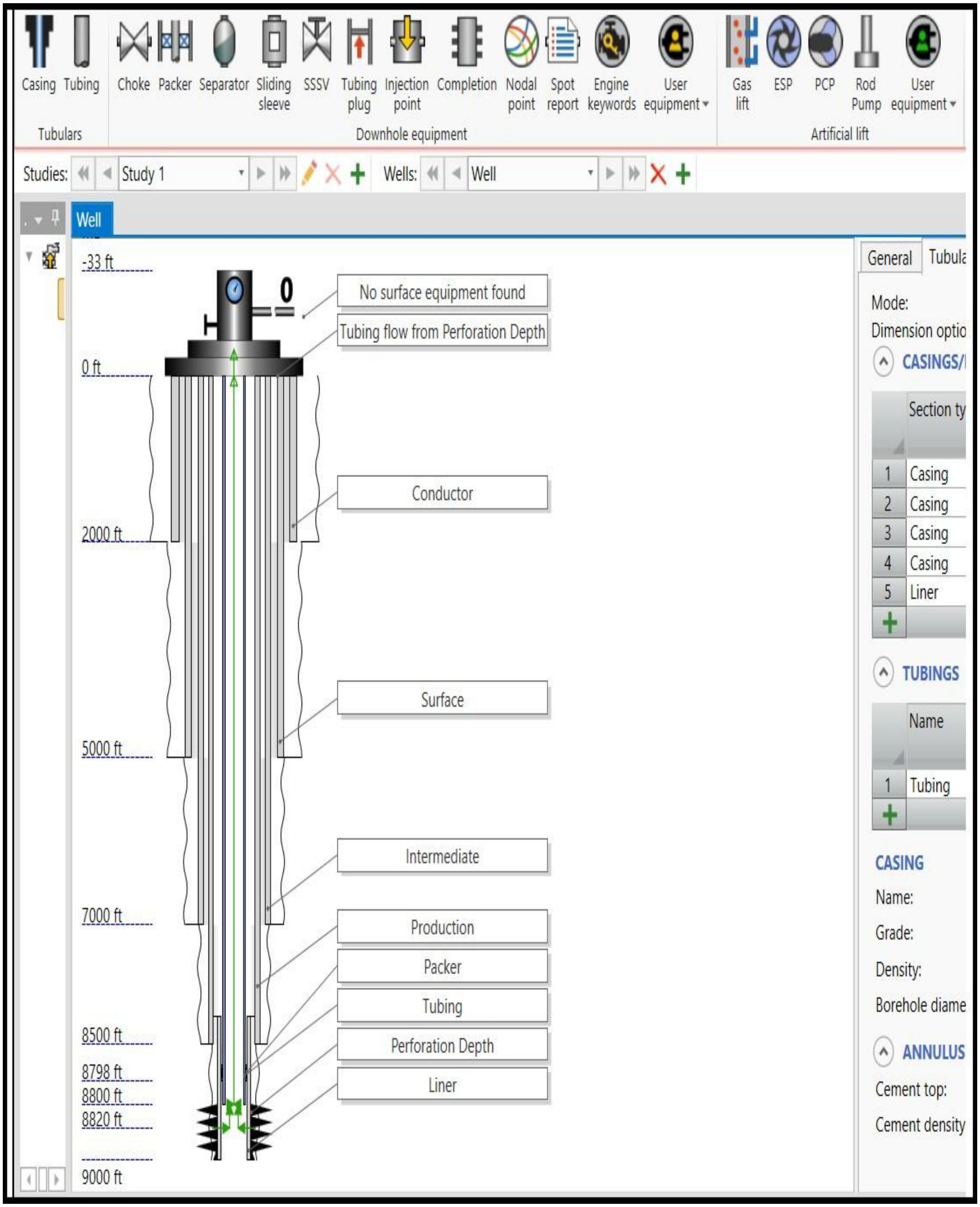


**Figure2:** Schematic Well Completion in PIPESIM

## 2.6 Modeling Inflow Performance Relationship

We then exit the task and continue the workflow by running a nodal analysis to determine the actual welldeliverability considering both the inflow and outflow. The inflow performance relationship curve isdisplayed on the reservoir subtab. We checked the box to use the Vogel equation below bubble point and the inflowperformancerelationshipcurveupdatestoshowtheVogelcorrectionfortwo-phaseeffects.Looking at the well schematic, we can see a dual flow path represented by green lines with arrows. Based on the current well schematic, the reservoir would produce concurrently through the annulus and the tubing. To isolate the fluid flow to a singular path through the tubing, we added a packer at 8499 feet. This completes the process of building the well model. the next step was to run the nodal analysis simulation task to determine the well deliverability. Using nodal analysis, we were able to determine how much production can be expected at the surface from a specified inflow and outflow.

## 2.7 Calibration

PIPESIM was used in this study to calibrate the measured data with laboratory data in order to improve the precision of fluid property calculations. The accuracy of the correlations for the system was improved by calibrating these characteristics throughout the range of pressures and temperatures. Actual observed values for PVT qualities frequently deviate from those calculated via correlations.

## 2.8 Electrical submersible pumps (ESP) Modeling

The electric submersible pumps (ESPs) were modeled in this study for effective optimization of a marginal oilfield operating in the Niger Delta. The ESP is perhaps the most versatile of the artificial lift methods (Schlumberger 2019). The ESP has the broadest producing range of any artificial lift method ranging from 100 b/d of total fluid up to 90,000 b/d. ESPs are currently operated in wells with bottom hole temperatures up to 350-degree Fahrenheit. The ESP comprises a down hole pump, electric power cable, motor and surface controls. In a typical application, the down hole pump is suspended on a tubing string hung on the wellhead and is submerged in the well fluid. The pump is close-coupled to a submersible electric motor that receives power through the power cable and surface controls (Figures 3 to 7).The design and simulation of ESP wells and natural flowing wells were done using PIPESIM Software (Figure 8).

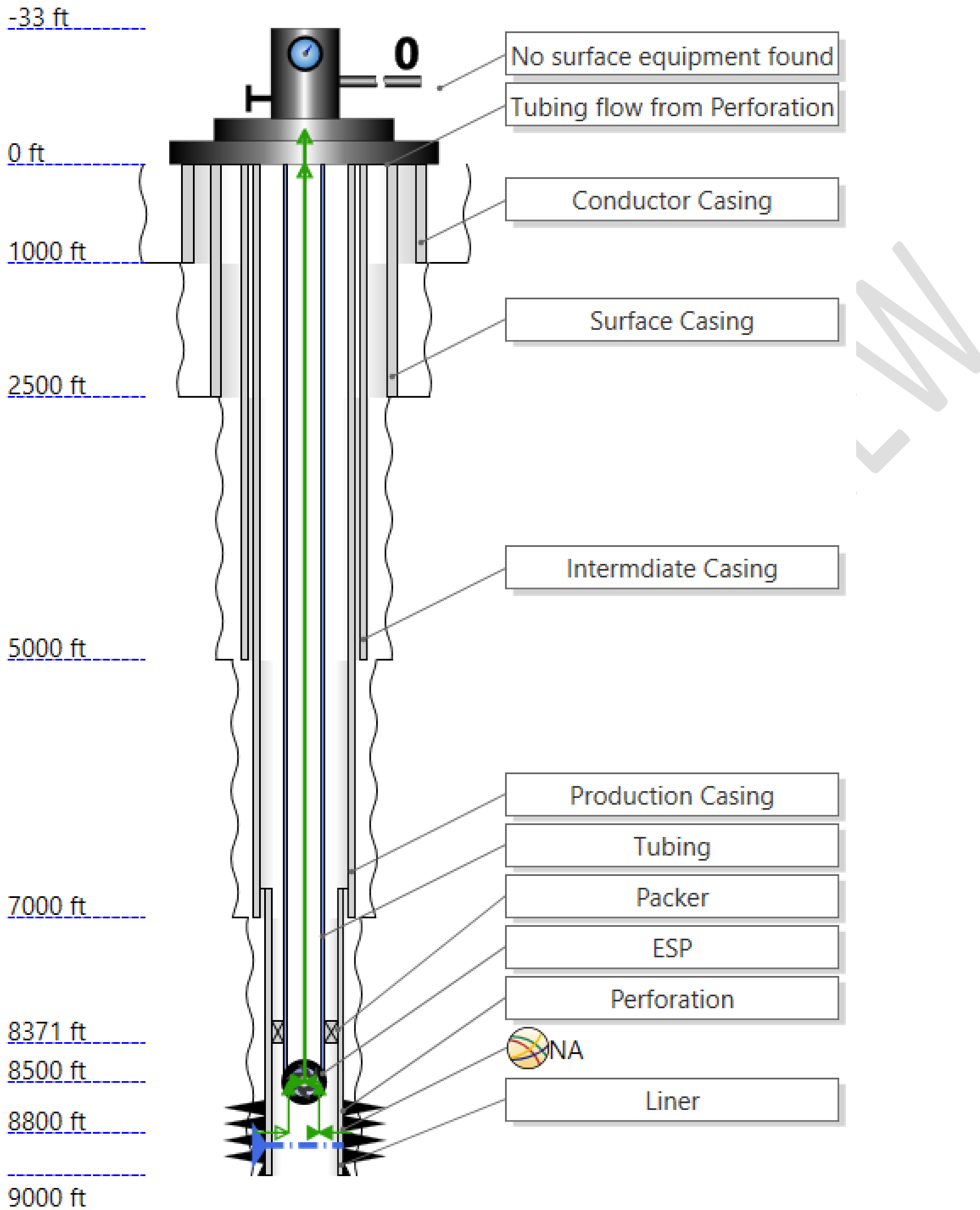


**Figure3:** Schematic ESP Well 1 Completion in PIPESIM

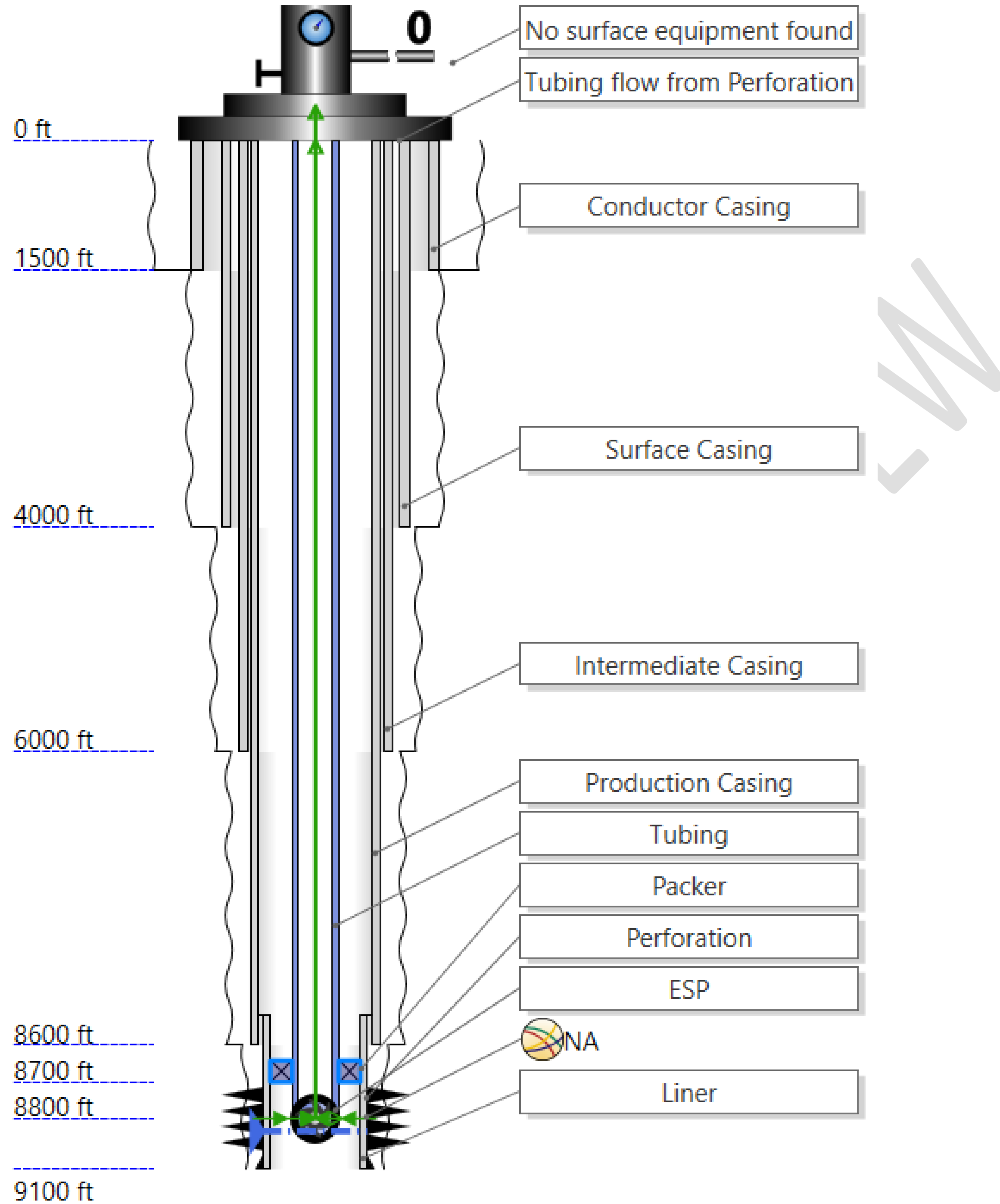


**Figure4:** Schematic ESP Well 2 Completion in PIPESIM

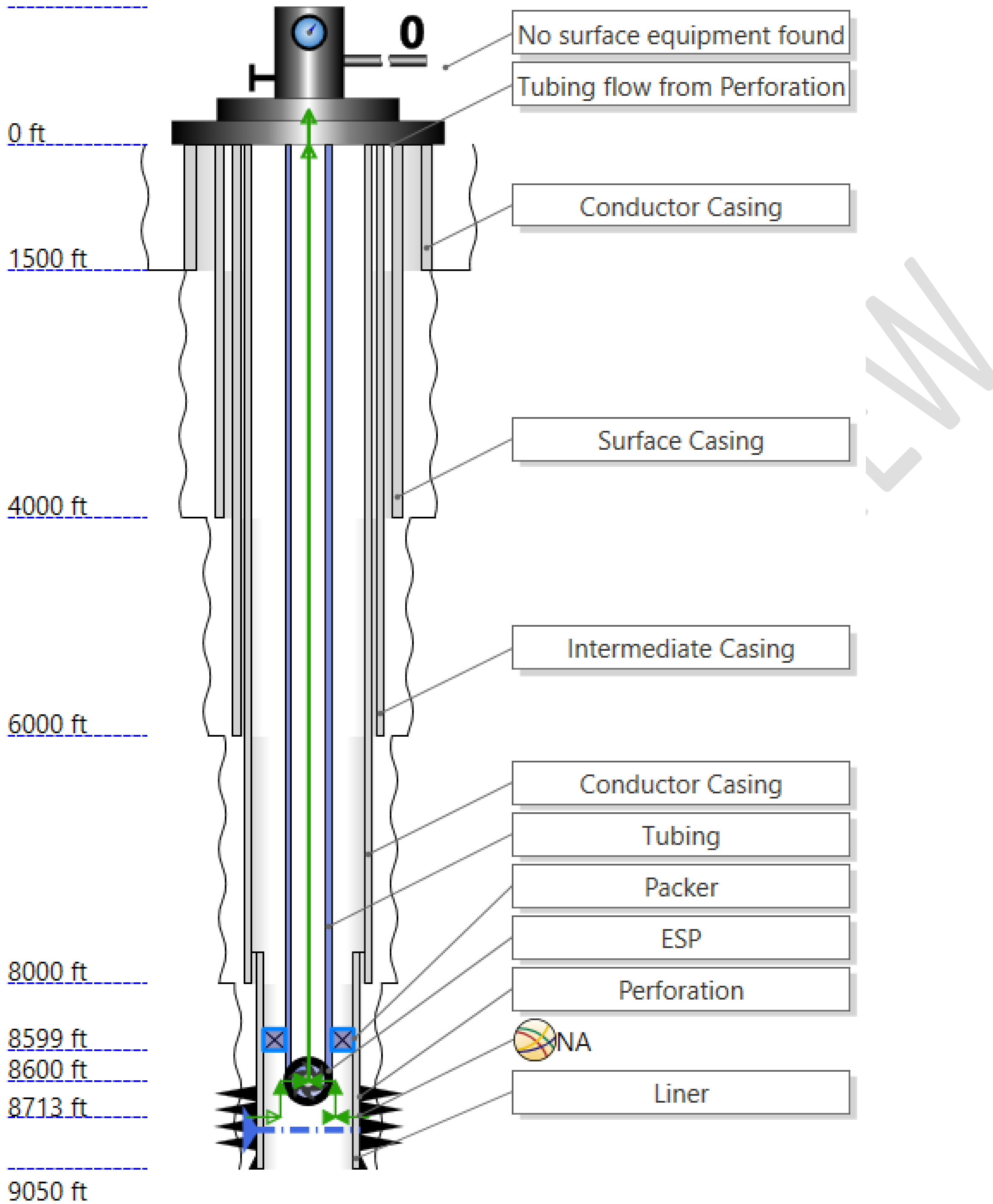


**Figure5:** Schematic ESP Well 3 Completion in PIPESIM

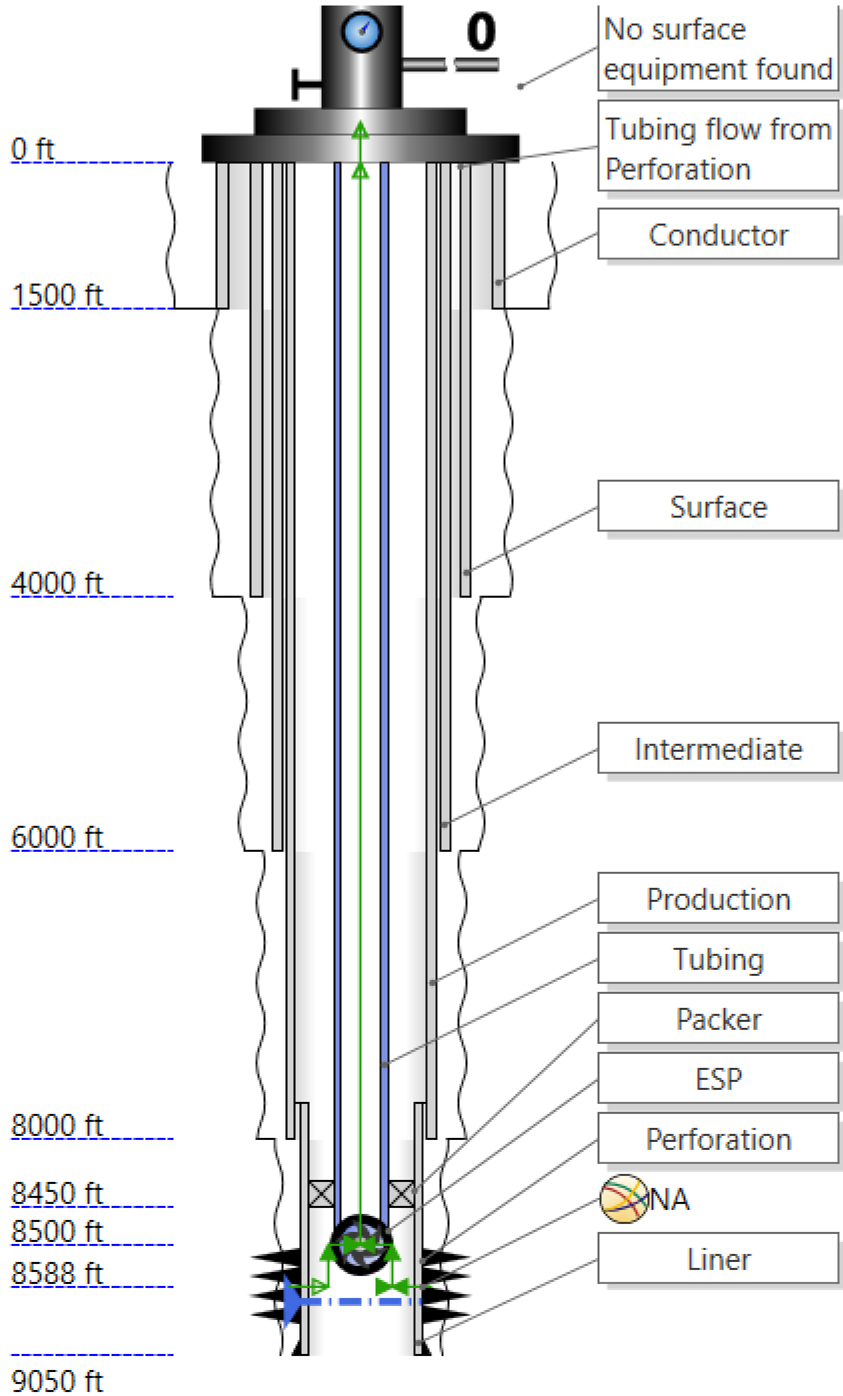


**Figure6:** Schematic ESP Well 4 Completion in PIPESIM

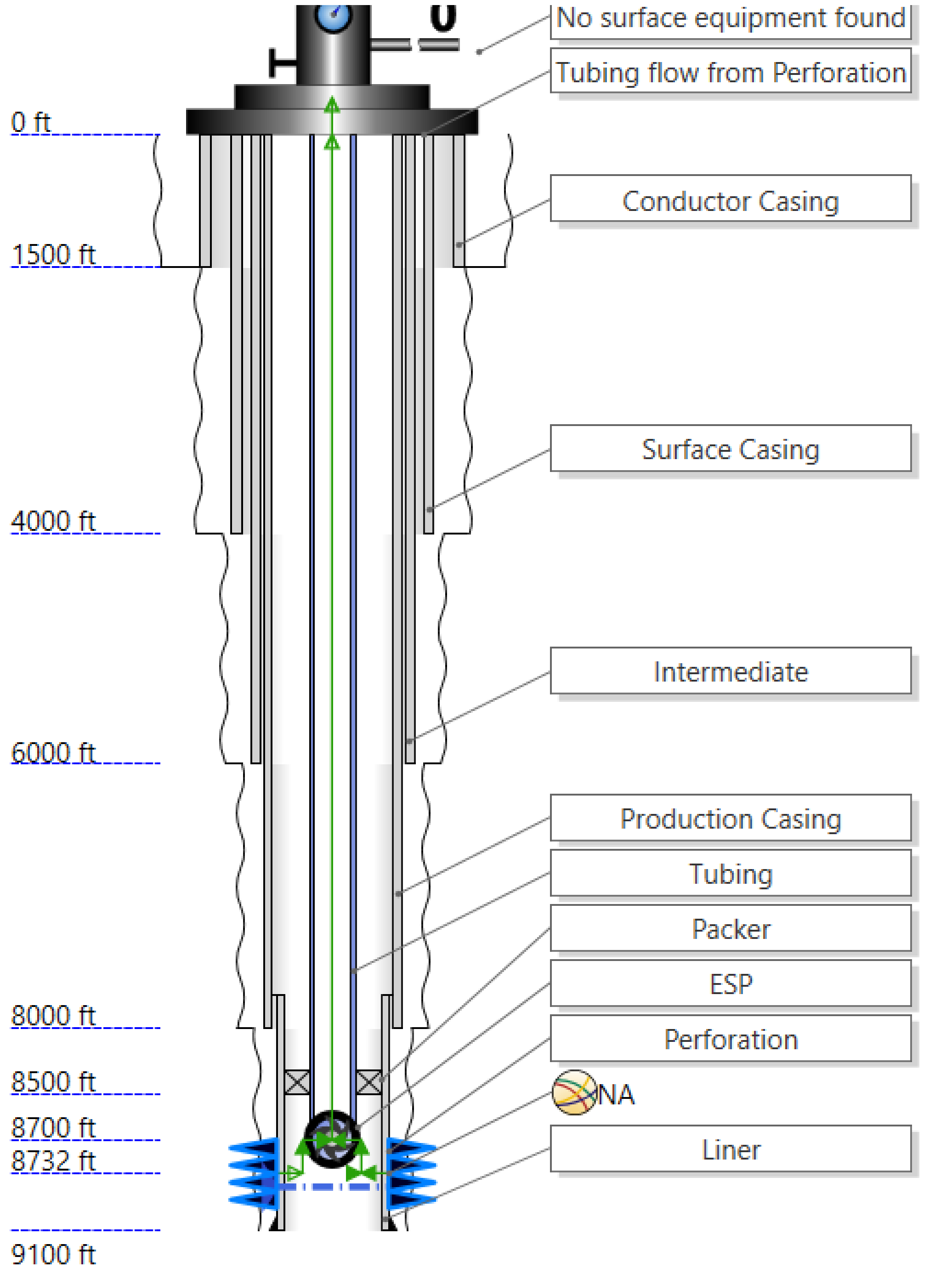


**Figure7:** Schematic ESP Well 5 Completion in PIPESIM

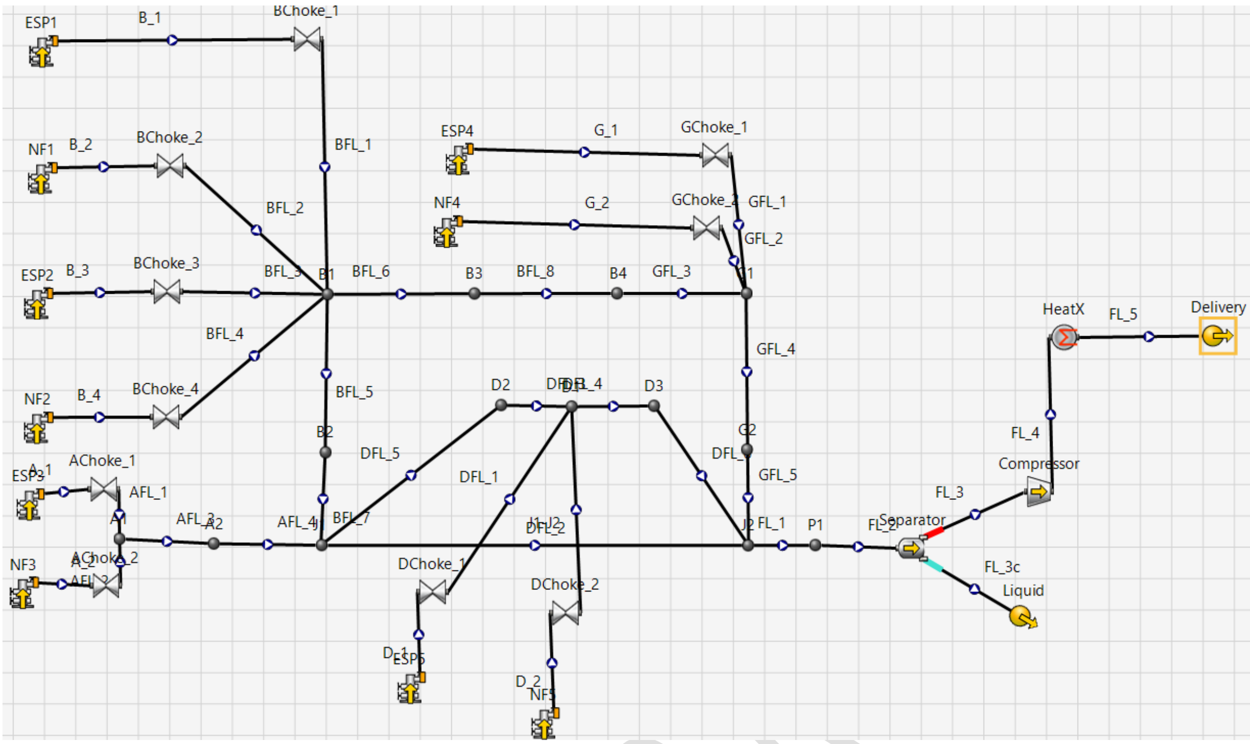


Figure 8: Oil Field Optimization With ESP

### 2.9 Reservoir Description

The reservoir description in this study was based on INTERSECT simulator. The reservoir model is made up of corner point and Cartesian with 36 grids in the x- direction, 51-grids in the y-direction, and 18 grids in the z-direction. In other words, the reservoir model was made up of 33,048 grids blocks (i.e., 36 x 51 x 18). The well 1 (oil production well) was located at (12, 21, 6), well 2 (oil production well) was located at (10, 31, 7), well 3 (oil production well) was located at (17, 16, 7), well 4 (oil production well) was located at (8, 34, 4), and well 5 (oil production well) was located at (7, 34, 4) (Figure 9 and 10).The results that were obtained in term of the reservoir`s oil production rate (OPR), water cut (WC), Gas Production Rate (GPR) and gas-oil ratio (GOR) are presented in chapter four.

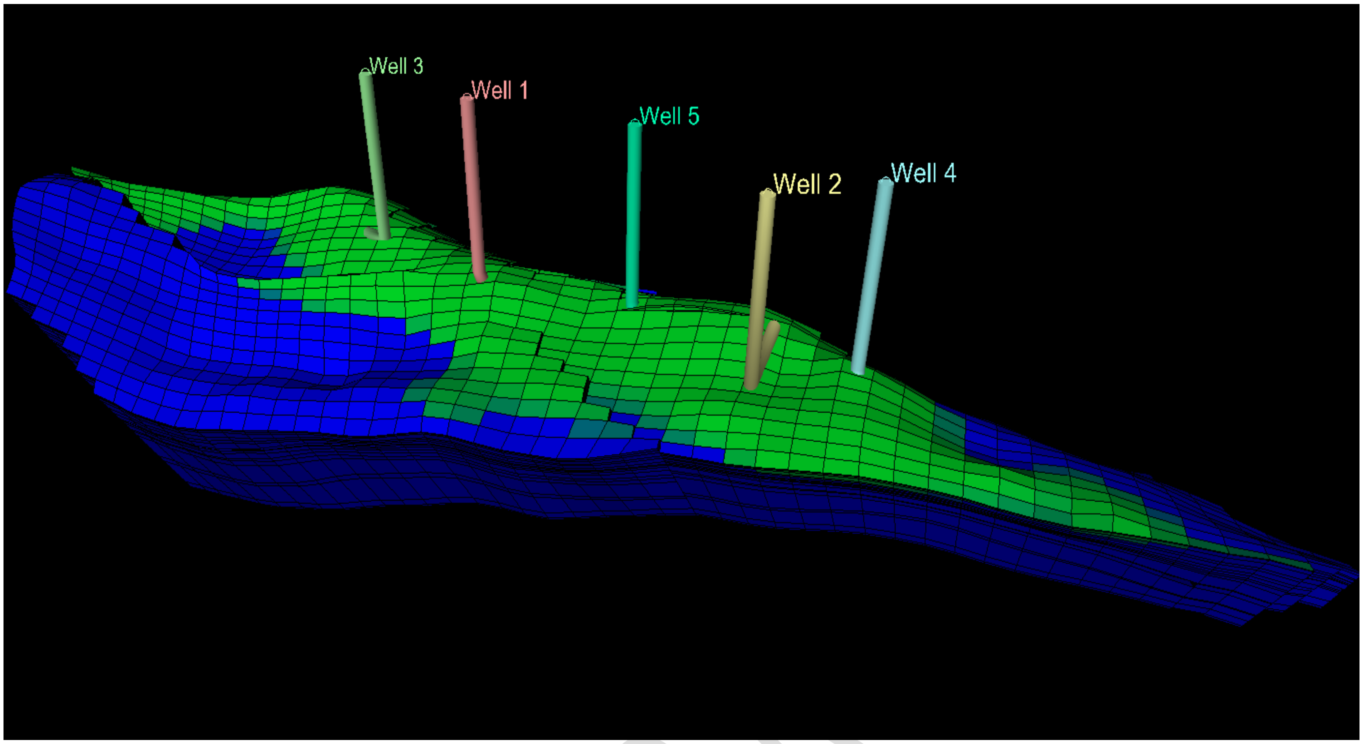


Figure 9: Reservoir Performance Before ESP

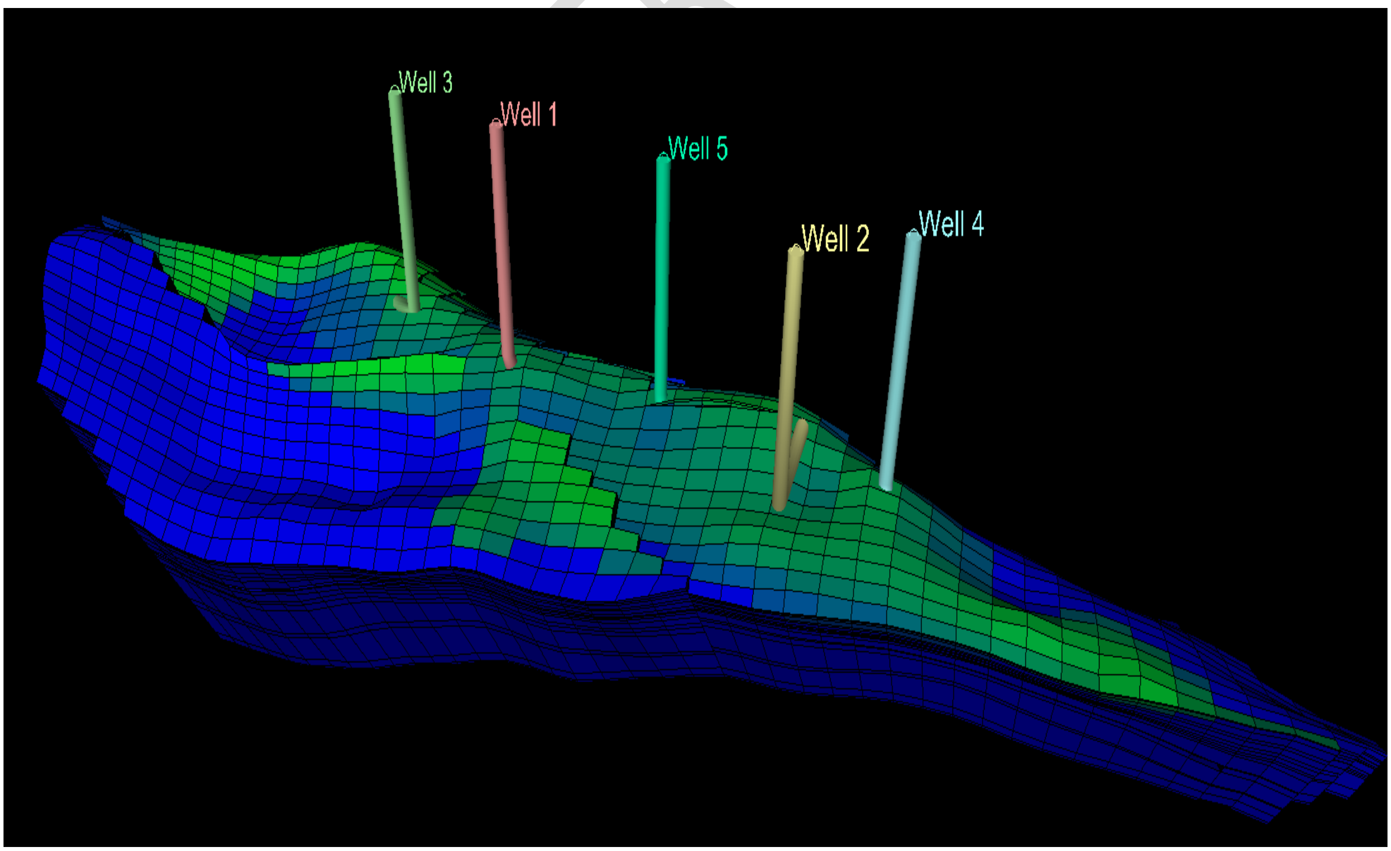


Figure 10: Reservoir Performance After ESP

## 3. Results

### 3.1 Production Performance of Wells (1 to 5) Before ESP

Figure 11 presents the summary results of the Production Performance of Natural Flowing Wells Before ESP was used as an effective means of optimizing production. From the graph, it was observed that, under natural flow conditions, wells will stop production due to insufficient energy to sustain production from the subsurface to the surface. From the simulation results, it can be seen that well 1 was at a constant production of 6000 stb/d before declining to 0 stb/d after 3 and half years. The same trends were observed in well 2 with a constant production of 4000 stb/d, well 3 with a constant production of 4000 stb/d, well 4 with a constant production of 8000 stb and well 5 with a constant production of 4000 stb/d before depleting to zero production after 3 and half years (Table 3).

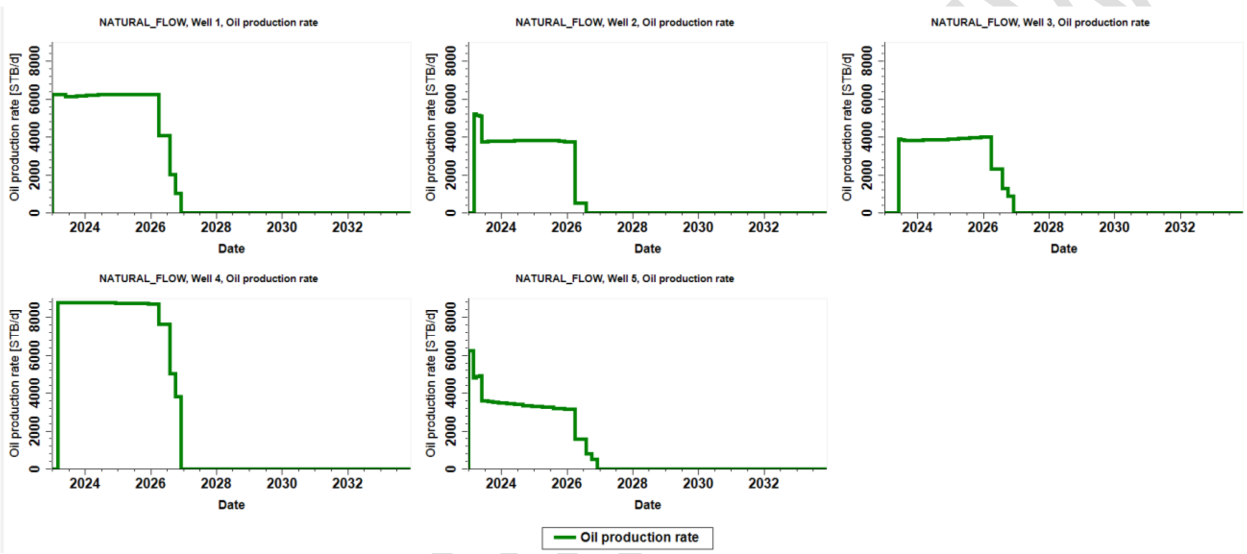


**Figure 11**: Production Performance of Natural Flowing Wells Before ESP

### 3.2 Production Performance of Wells (1 To 5) Assisted With ESP

Figure 12 presents the summary results of the Production Performance of Wells (1 to 5) assisted with ESP. From the graph, it was observed that, the production life of the wells was optimized after installation of ESPs. From the simulation results, it can be seen that well 1 was at a constant production of 6000 stb/d for the period of 5 years before gradually declining to 2000 stb/d after 10 years of production. The same trends were observed in well 2, well 4 and well 5 with their respective production rates declining to 2000 stb/d after 10 years of production. Well 4 was at the increase from 4000 stb/d to 6000 stb/d after 6 years of production before gradually declining to 4000 stb/d after 10 years of production.

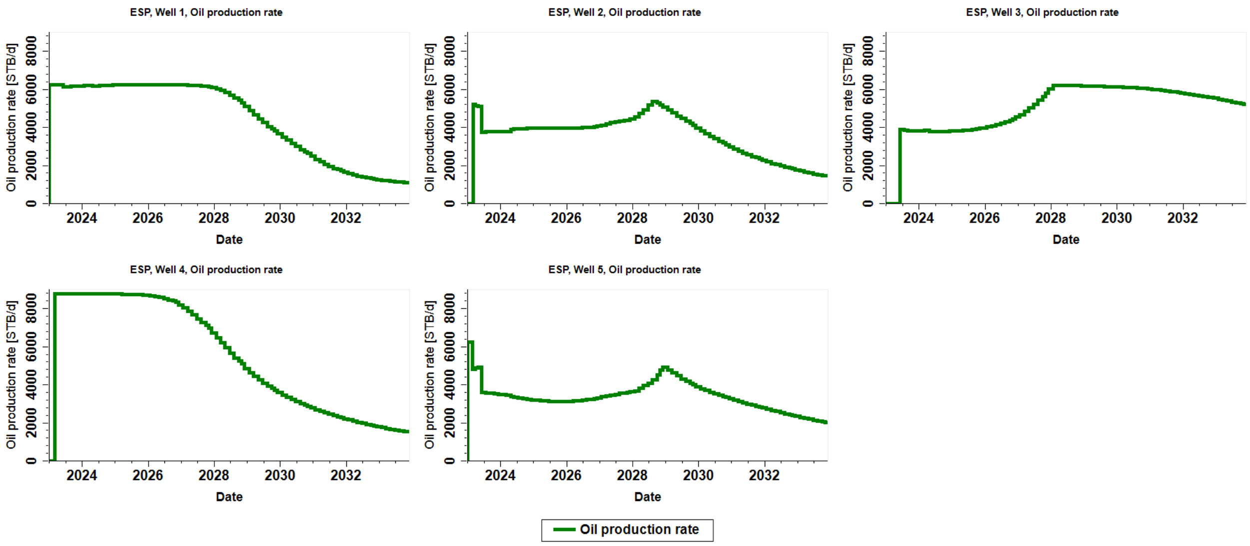


**Figure 12:** Production Performance of Wells (1 to 5) with ESP

### 3.3 Production Performance of the Well 1 With and Without ESP.

Figure 13 presents the result of the Production Performance the Well 1 with and without ESP. From the graph, it was observed that, the incremental oil production of well 1 was optimized after the installations of ESP. From the simulation results, it can be seen that, well 1 under natural flow conditions depleted to 0 stb/d after 3 years of production. The same well was able to produce at a constant production of 6000 stb/d for the period of 5 years before gradually declining to 2000 stb/d after 10 years of production with the help of ESP.

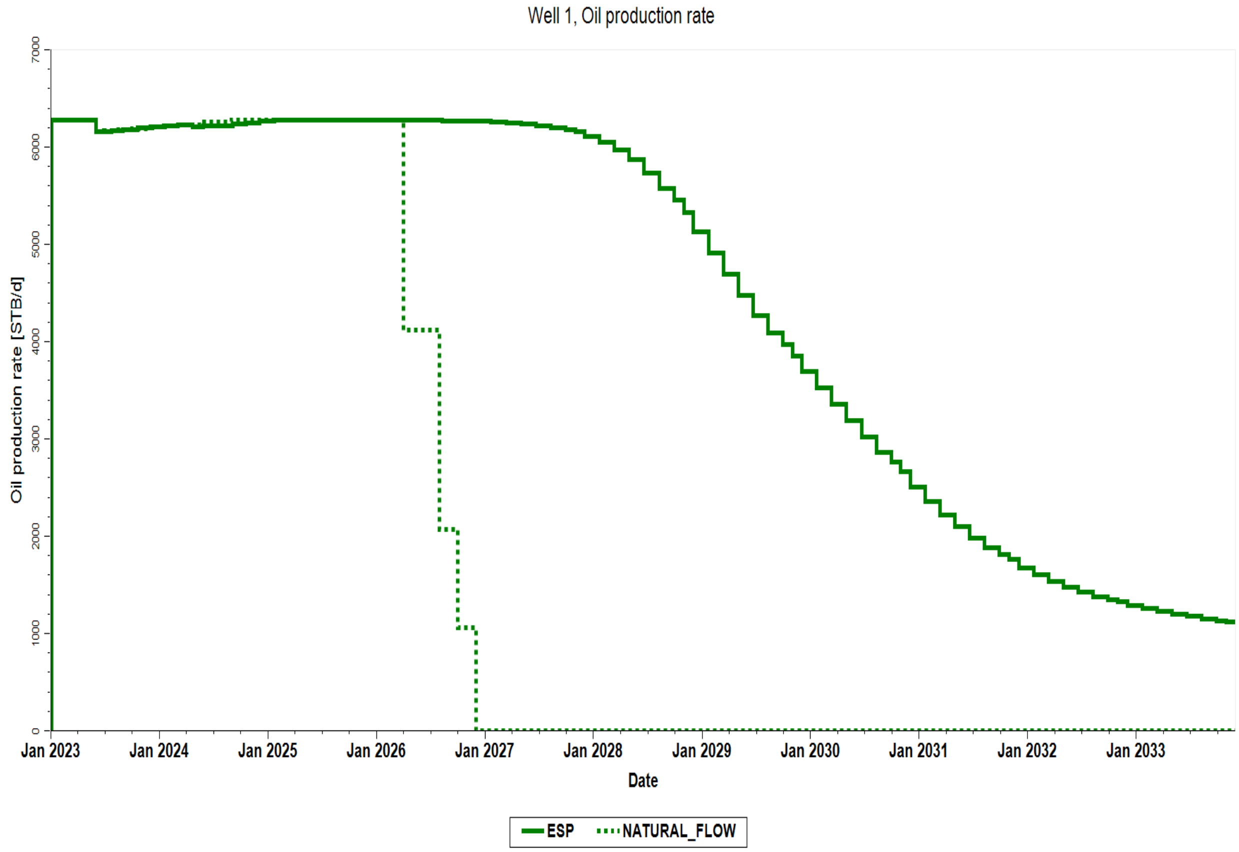


Figure 13: presents the result of the Production Performance of Well 1 with and without ESP



### 3.4 Production Performance of the Well 2 With and Without ESP

Figure 14 presents the result of the Production Performance of Well 2 with and without ESP. From the graph, it was observed that, the incremental oil production of well 2 was optimized after the help of ESP. From (Figure 14), it can be seen that, the production of well 2 under natural flow was terminated after 3 years of production. The same well 2 assisted with ESP was able to produce at a steady increase from 4000 to 5000 stb/d for the period of 6 years before declining to 1500 stb/d after 10 years of production.

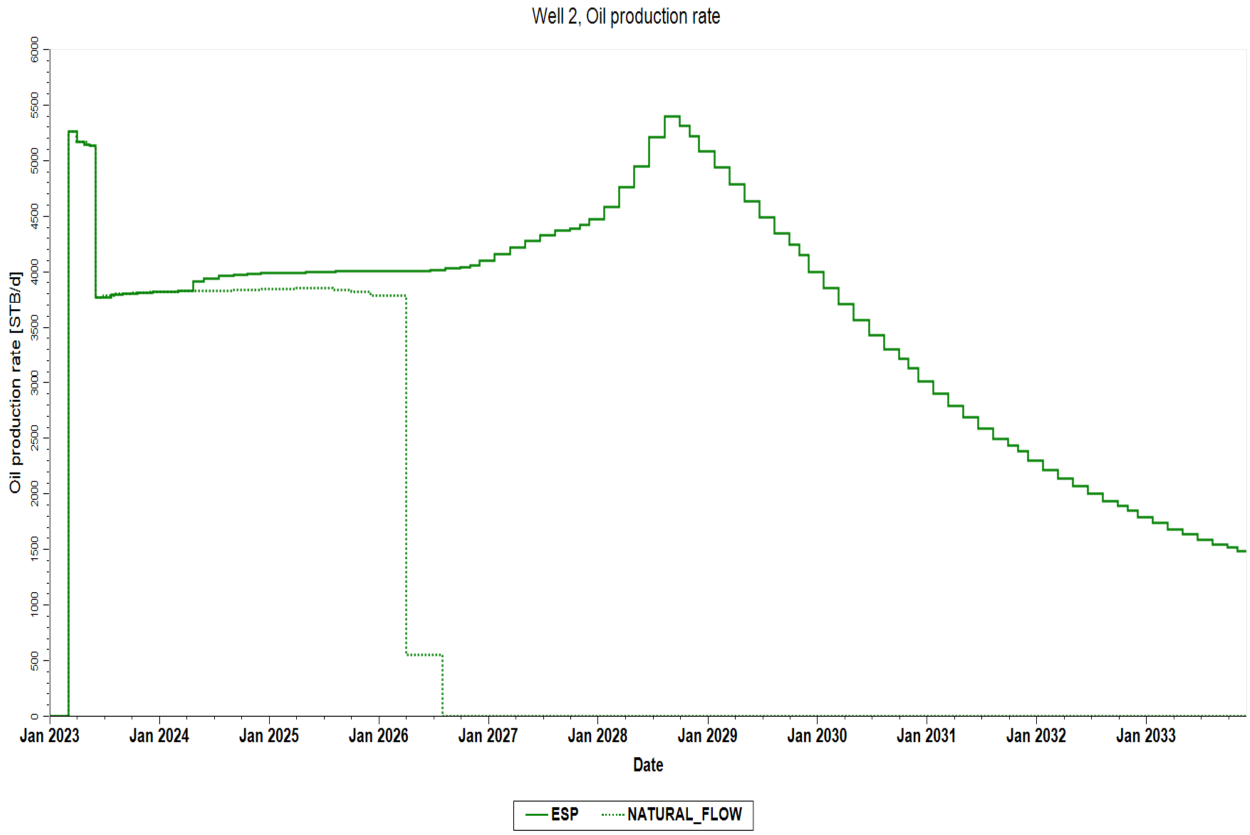


**Figure 14**: presents the result of the Production Performance of Well 2 with and without ESP

### 3.5 Production Performance of The Well 3 With and Without ESP

Figure 15 presents result of the Production Performance of Well 3 with and without ESP. From the graph, it was observed that, the incremental oil production of well 3 was optimized after the help of ESP. From (Figure 15), it can be seen that, the production of well 3 under natural flow was terminated after 3 years of production. The same well 3 assisted with ESP was able to produce at a steady increase from 4000 to 6000 stb/d for the period of 6 years before gradually declining to 4800 stb/d after 10 years of production.

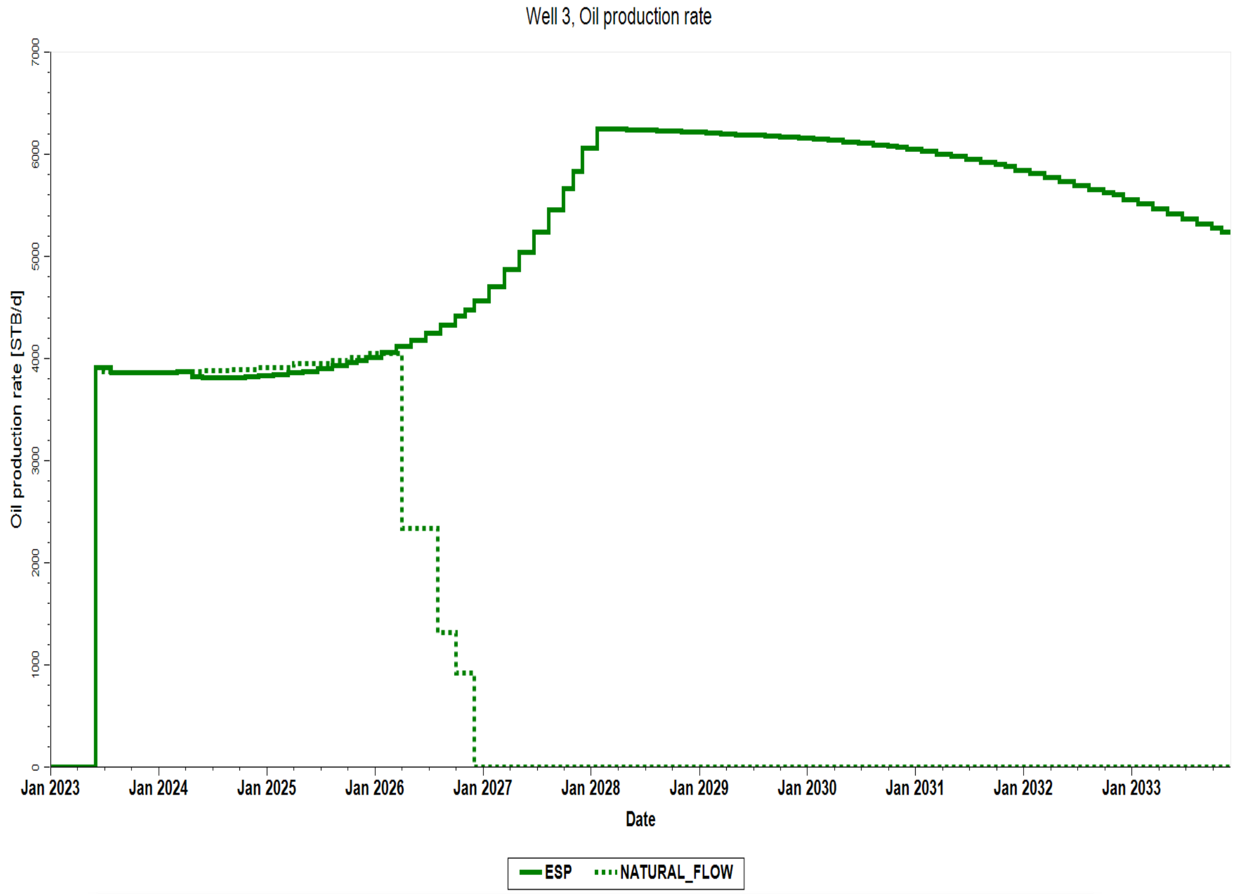


**Figure 15**: presents result of the Production Performance of Well 3 with and without ESP.

### 3.6 Production Performance of the Well 4 With and Without ESP

Figure 16 presents the result of the Production Performance of Well 4 with and without ESP. From the graph, it was observed that, the incremental oil production of well 4 was optimized after the installation of ESP. From the simulation results, it can be seen that, well 4 was at a constant production 8000 stb/d for the period of 3 years before being depleted to 0 stb/d production. The same well 4 with the help of ESP was able to produce at a constant production of 8000 stb/d for the period of years before gradually declining to 2000 stb/d after 10 years of production.

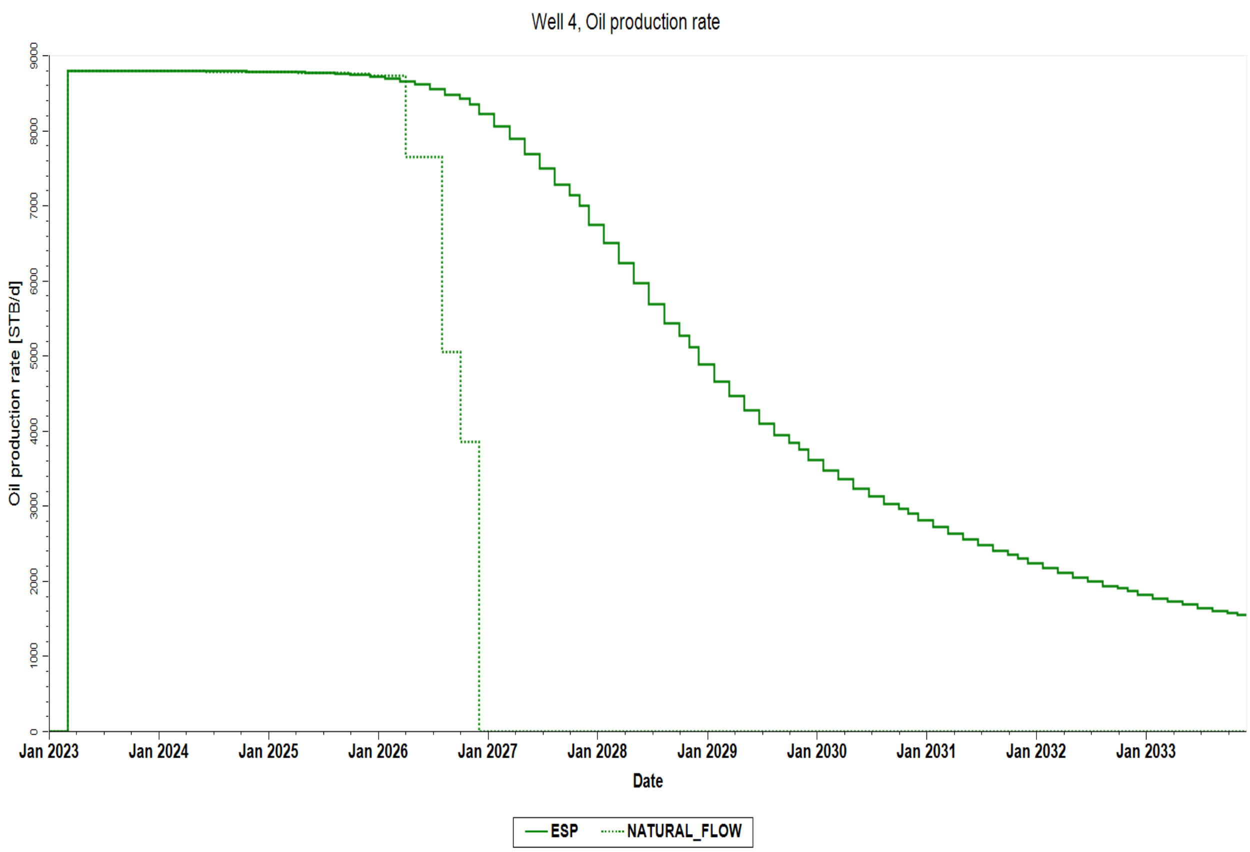


**Figure 16:** presents result of the Production Performance of Well 4 with and without ESP

### 3.7 Production Performance of the Well 5 With and Without ESP

Figure 17 presents the result of Production Performance of the Well 5 with and without ESP. From the graph, it was observed that, the incremental oil production of well 5 was optimized with the help of ESP. From the (Figure 17), it can be seen that, the production of well 5 under natural flow was terminated after 3 years of production. The same well 5 assisted with ESP was able to produce at a steady increase from 4000 to 5000 stb/d for the period of 6 years before declining to 2000 stb/d after 10 years of production.

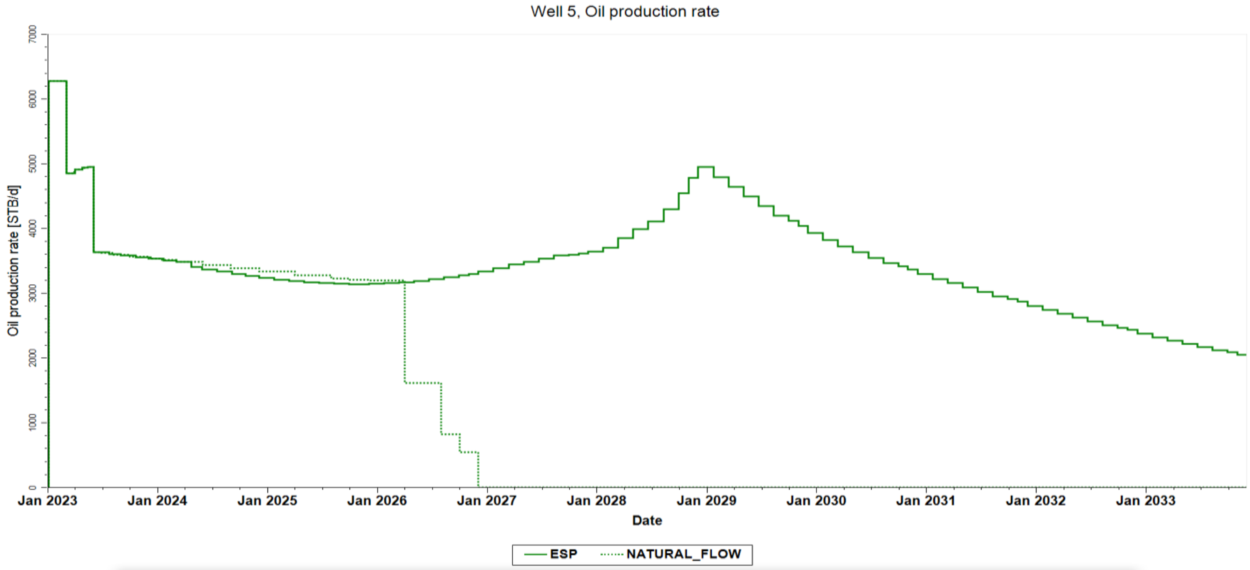


Figure 17 presents result of the Production Performance of Well 5 with and without ESP.

### 3.8 Summary of Production Performance of Wells with and Without ESP

Figure 18 presents the summary results of the Production Performance of Wells with and without ESP. From the graph, it was observed that, the incremental oil production of wells was optimized with the help of ESP. From (Figure 18), it can be seen that, the production of wells under natural flow were terminated after 3 years of production. The same wells assisted with ESP were able to produce 4 to 6 years before some wells declined to 1500 stb/d after 10 years of production.

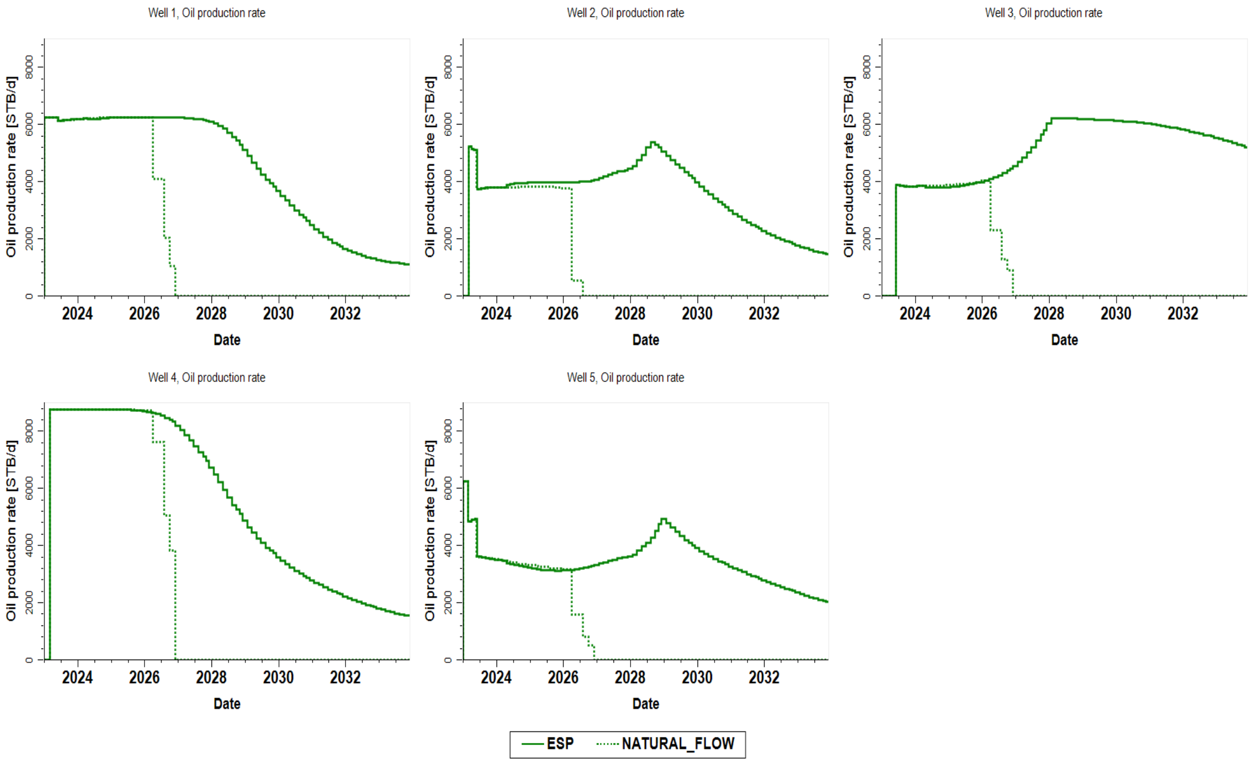


Figure 18: Summary results of the Production Performance of Wells with and without ESP

### 3.9 Cumulative oil Production Performance of the Wells with and Without ESP

Figure 19 presents the cumulative oil production Performance of Wells with and without ESP. From the graph, it can be seen that, the incremental oil production after the installation of ESPs is higher than that of natural flowing wells. From the simulation results, it was observed that the cumulative oil recovery from natural flowing well 1 was 7,299,993 stb while that obtained from ESP well 1 was 16,000,000 stb (about 219% oil increment). The cumulative oil recovery from natural flowing well 2 was 4,055,557 stb while that obtained from ESP well 2 was 13,000,000 stb (about 321% oil increment). The cumulative oil recovery from natural flowing well 3 was 4,038,380 stb while that obtained from ESP well 3 was 18,000,000 stb (about 446% oil increment). The cumulative oil recovery from natural flowing well 4 was 10,000,000 stb while that obtained from ESP well 4 was 20,000,000 stb (about 200% oil increment). The cumulative oil recovery from natural flowing well 5 was 4,155,315 stb while that obtained from ESP well 5 was 12,000,000 stb (about 289% oil increment).

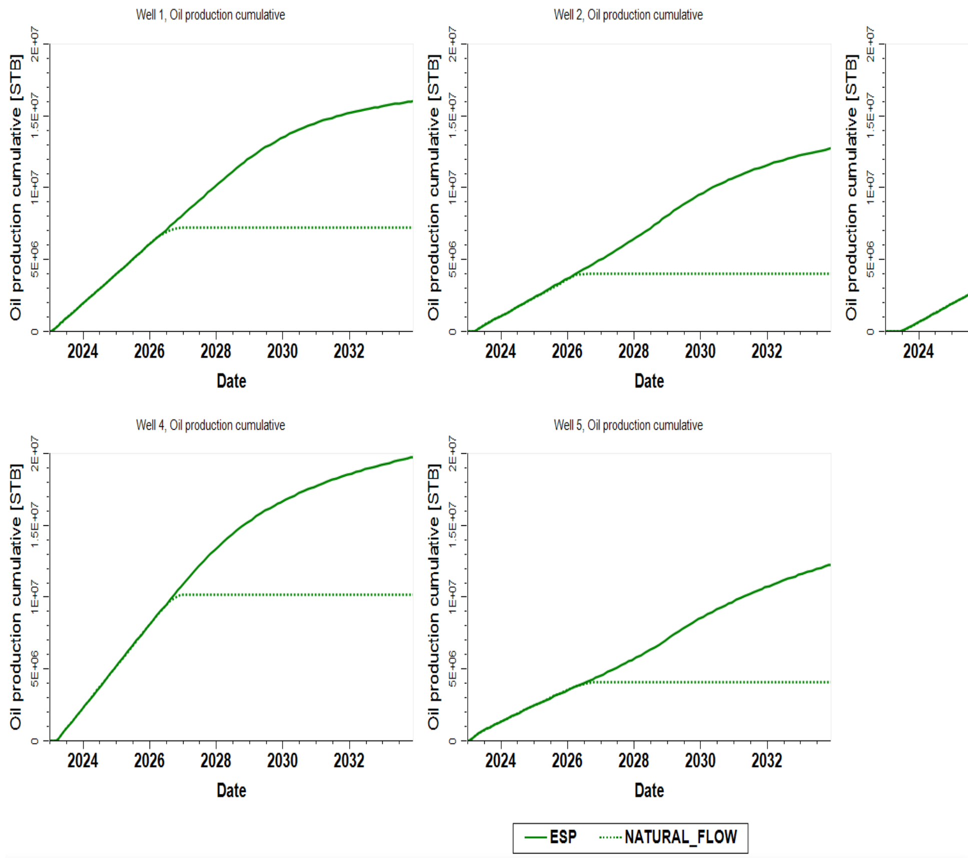


Figure 19: Cumulative Production Performance of Wells with and without ESP

### 3.10 Cumulative oil production Performance of the Oilfield with and Without ESP

Figure 20 presents the cumulative oil production Performance of the oilfield with and without ESP. From the graph, it can be seen that, the incremental oil production after the installation of ESPs is higher than that of natural flowing wells. From the simulation results, it was observed that the cumulative oil recovery without ESP was 33,684,736 stb while that recovered with ESP was 87,751,136 stb (about 261% oil increment).

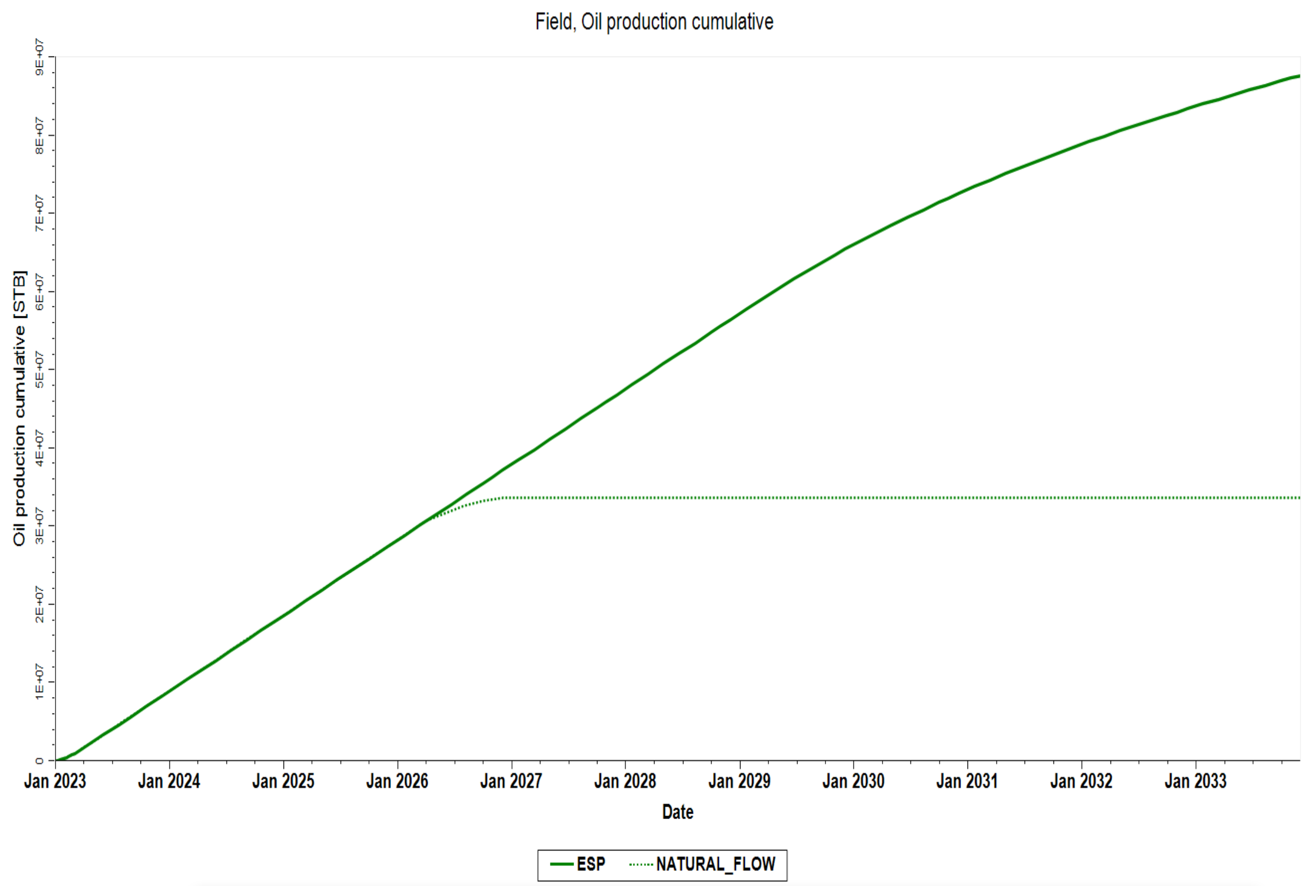


**Figure 20:** Cumulative Oil Production Performance with and Without ESP

### 3.11 Summary of Findings

In summary, the performance ofESP wells had been simulated and compared with the naturally flowing wells. From the simulation results, it was observed that;

I. The cumulative oil recovery from natural flowing well 1 was 7,299,993 stb while that obtained from ESP well 1 was 16,000,000 stb (about 219% oil increment).

II. The cumulative oil recovery from natural flowing well 2 was 4,055,557 stb while that obtained from ESP well 2 was 13,000,000 stb (about 321% oil increment).

III. The cumulative oil recovery from natural flowing well 3 was 4,038,380 stb while that obtained from ESP well 3 was 18,000,000 stb (about 446% oil increment).

IV. The cumulative oil recovery from natural flowing well 4 was 10,000,000 stb while that obtained from ESP well 4 was 20,000,000 stb (about 200% oil increment).

V. The cumulative oil recovery from natural flowing well 5 was 4,155,315 stb while that obtained from ESP well 5 was 12,000,000 stb (about 289% oil increment) respectively.

## 4. Conclusion

Simulation studies were conducted using data from wells operating in the Niger Delta. The performance of natural flowing wells and ESP wells was compared. This study also reflects the economics of using ESP The results obtained from the production forecast showed that the ESP wells gave a superior oil production when compared to natural flowing wells. Considering the cost and production potential deriving from ESP wells, the performance of ESP well is the best both in terms of production increase and gross profit which are the major factors in any investment decision-making. Through consideration of the production profile, desired rate and economic analysis of ESP for production optimization in the Niger Delta marginal oilfield, the ESP system is capable of increasing oil production and improving revenue.

## 5. Recommendations

I. The field in which ESP is to be implemented should have a well layout pattern for effective design and optimization of the field**.**

II. More detailed studies involving different modeling, reservoir properties, and production

III. conditions should be done to get a better understanding of artificial lift operations in the Niger Delta Oil Field.

IV. The optimized operational strategy of the ESP should be considered before any marginal oilfield practice.

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