

Techno-Economic Evaluation of Current Technologies for Producing a Heavy Oil Reservoir in the Niger Delta

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ABSTRACT

Development of heavy oil reservoirs is always difficult to justify. This is majorly due to the low recovery factors from these type of reservoirs. Different technology and development options have been widely considered and utilized for the production of oil from these fields. This research is a study of the Ikpeba field, a heavy oil field located in the Niger Delta Basin of Nigeria. It is classified as a heavy oil field due to the nature of the fluids in the reservoir which has a low API gravity of 17°API. The field has one well completed in the deepest reservoir, but it is unable to flow naturally. Therefore, there is a need to consider the application of different recovery techniques to identify those recovery methods that are technically and economically viable to produce the well. Different recovery methods were screened using the Enhanced Oil Recovery (EOR) screening criteria developed by Taber et al. (1997). Three techniques were considered for optimal oil recovery from this field; production through the already drilled vertical well which served as the base case, drilling and production of a new horizontal well and, production using polymer flooding. ECLIPSE simulation software was used to evaluate the technical feasibility of producing the heavy oil reservoir. Polymer flooding was found to meet the criteria of producing the Ikpeba heavy oil field. It was observed that producing the heavy oil using the vertical well, horizontal well and polymer flooding gave recovery factors of 1.7%, 4.6%, and 8.22%, respectively. Additionally, an economic analysis was performed considering both the horizontal well production and the polymer flooding to examine the economic feasibility of the two recovery methods. The net present value (NPV), internal rate of return (IRR) and discounted payback period were used as the baseline for the economic analysis. The horizontal well has an NPV of \$2.8 million and a discounted payback period of 4.5 years, while the polymer flooding has an NPV of \$4.4 and a discounted payback period of 5.5 years. It is recommended that similar study should be done for other heavy oil fields in the Niger Delta region.

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INTRODUCTION

Production of unconventional resources such as oil shale, heavy oil, coal-to-liquids, biofuel, bitumen, gas to liquids and shale oil is forecasted to increase on an average by 4.6 percent per year over 25 years (Conti and Holtberg, 2011). Although the oil and gas industry is witnessing an increase in the development of the unconventional resources,

the commercialization of the asset is plagued with several challenges, including high production and asset development costs, complex resource recovery processes and environmental concerns (Conti and Holtberg 2011).

Heavy oil reservoirs are defined as reservoirs with high viscosity (higher than 100cp) and low American Petroleum Institute

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(API) gravity (less than 22°API) oil (Santos et al., 2013). Development of heavy oil reservoirs is always difficult to justify, this is majorly due to the low recovery factors from these reservoirs (Shah et al., 2010). Different technology and development options have been widely considered and utilized for production and optimization of oil recovery from these fields.

Primary oil recovery methods are not suitable for recovering heavy oils because of the nature of the oils; nearly non-mobile characteristics and low recovery factors (Brook and Kantzas, 1998). The recovery technologies that have been used to produce heavy oil reservoirs are classified as enhanced oil recovery methods. These methods include water flooding, polymer flooding, immiscible gas injection, steam injection, thermal recovery techniques, alkaline injection, and surfactant injection (Alajmi, et al., 2009; Brook and Kantzas, 1998; Dong et al., 2019; Gates, 201; Huang et al., 2019; Li et al., 2019; Liu et al., 2019; Mozaffari et al., 2013; Wang et al., 2019). In some cases, heavy oil reservoirs have been produced by drilling horizontal wells. According to Meyer et al. (2007), of all these recovery methods, immiscible gas injection, polymer flooding and in-situ combustion (fire flood) have met with limited success for producing heavy oils and that steam injection (cyclic steam, huff 'n' puff, steam flooding) has been the most successful; frequently by using cyclic steam followed by steam flooding. Steam-assisted gravity drainage (SAGD) has also been used successfully in the production of bitumen in Canada.

This research work considered the technical feasibility of current technologies for producing a heavy oil reservoir in Ikpeba field located in the Niger Delta. Ikpeba field which is a heavy oil reservoir has one well with a down-hole ESP installed. The well was produced, and in just a few hours it was shut in because it could not produce for up to four hours before water conning occurred. Therefore, there is a need to characterize the reservoir, evaluate the production from the well and the application of different oil recovery techniques to identify those recovery methods that are technologically

and economically viable in the production of the heavy oil from the Ikpeba field.

RESEARCH METHODOLOGY

To evaluate the technical and economic value of enhanced oil recovery methods which are suitable for the Niger Delta heavy oil reservoir, the fluid and rock properties and EOR methods must be adequately studied. In this study, the PVT data was modeled to study the characteristics of the heavy oil from a Niger Delta reservoir (Ikpeba field). The EOR selection criteria developed by Taber (1997) and updated by several authors was used to select the methods that were feasible in the Niger Delta region. A dynamic model was developed using ECLIPSE simulation software to study the technical feasibility of the selected EOR methods and finally, an economic analysis was done to evaluate their economic merits.

EOR Screening Criteria

Considering the virtually limitless list of EOR methods and their various combinations, conducting a detailed study on each method to assess its suitability for application to a specific asset may not be logical (Alajmi, 2013). Therefore, the available EOR methods need to be screened to select and recommend the most technically and economically viable scheme(s) to develop the field. The screening criteria is based on a combination of the reservoir and fluid characteristics of successful projects and our understanding of the optimum conditions needed for good fluid displacement by the different EOR processes. Comparisons of these criteria against values from the reservoir of interest indicate the possible future success of the EOR methods. Many of the screening criteria are related to the reservoir rock and fluid properties such as net-pay thickness, depth, permeability, porosity, oil saturation, initial reservoir pressure, viscosity, etc. to restrict the scope for investigating the right set of EOR processes (Taber et al., 1997). Table 1 shows the reservoir rock and fluid properties of the case study (Ikpeba field).

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Table 1: Reservoir and fluid properties of Ikpeba field (N4000 Reservoir)

Reservoir and Fluid Properties	Units	Value
API gravity	°API	16.96
Oil Density	Kg/m ³	952.3
Oil Viscosity	cP	61
Porosity	%	30
Permeability	Md	1600
Formation Type		Sandstone
Reservoir Temperature	°F	200
Initial Reservoir Pressure	Psia	3200
Depth	Ft	7300
Net-pay thickness	Ft	40
Oil saturation	%	80
Bubble point pressure	Psi	1650
Water compressibility@3,200 psi	Psi ⁻¹	3.067E-6
Rock Compressibility	Psi ⁻¹	1.782
Water density	lb/ft ³	62.43
Gas specific gravity (SG Air = 1)		0.596

To select the most suitable EOR method for the optimization of recovery from the Ikpeba field, this study focuses on the screening criteria developed by Taber et al (1983, 1997), Al-Bahar et al. (2004), and King et al. (1984), which was later updated by different authors to

encompass the recent EOR methods. Table 3.2 shows the EOR screening criteria published by Taber et al. (1997) which was updated by Aladasani (2010), to include EOR survey reports submitted from 1998 through to 2010.

Table 2: Updated EOR Selection Criteria (Source: Aladasani, 2010)

S/N	EOR Method	Oil Properties		Reservoir Properties						
		Gravity (°API)	Viscosity (cp)	Porosity (%)	Oil saturation (%PV)	Formation Type	Average Permeability (md)	Net Thickness (ft)	Depth (ft)	Temp (°F)
1	CO2 Miscible	22-45	0.1-35	3-37	15-89	sandstone or carbonate	1.5-4500	wide range	1500-13365	82-257
2	Hydrocarbon Miscible	23-57	0.04-18000	4.25-45	30-98	sandstone or carbonate	0.1-5000	Thin unless dipping	4000-15900	85-329
3	WAG	33-39	0.3-0.9	11-24		Sandstone	130-1000	NC	7545-8887	194-253
4	Nitrogen Miscible	38-54	0-0.2	7.5-14	0.76-0.8	Sandstone or carbonate	0.2-35	Thin unless dipping	6000-18500	190-325
5	Nitrogen Immiscible	Avg 34.6	0-18000	11-28	47-98.5	sandstone	3-2000		1700-18500	82-325
6	CO2 Immiscible	Avg 22.6	0.6-592	17-32	42-78	sandstone or carbonate	30-1000		1150-8500	82-198
7	Hydrocarbon Immiscible	22-48	0.25-4	>22	75-83	sandstone	40-1000		6000-7000	170-180
8	Polymer	13-42.5	0.4-4000	10-33	34-82	sandstone	1.8-5500	NC	700-9460	74-237
9	ASP	23-34	11-6500	26-32	68-74.8	sandstone	596-1520	NC	2700-3900	118-158
10	Surfactant	22-39	2.63-15.6	14-16.8	43.5-53	sandstone	50-60	NC	5300-625	122-155
11	In-situ combustion	11-38	<5000	14-35	50-94	sandstone or carbonate	10-15000	>10	400-11300	64.4-230

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12	Steam	8-33	<2000-5000	12—65	35-90	sandstone	1-15000	>20	200-9000	10-350
13	Hot Water	>12	50-8000	>12	15-85	sandstone	900-6000	>30	500-3000	75-135

Table 3 summarizes the EOR screening results from the Ikpeba field and shows the EOR methods which are to be progressed to the next stage of the research.

Note in Table 3.3; the column labeled “Reason” presents the justifications, i.e., the parameters that accounted for the failure of a particular EOR process to apply to the reservoir

Table 3: Results of the Enhanced Oil Recovery (EOR) screening study of the Ikpeba field

S/N	Methods	Process	Result	Reason for Failure
1	Primary Production	CHOPS	Fail	Depth < 7000ft
2	Chemical	Polymer Flooding	Pass	
3		Surfactant Flooding	Fail	API gravity > 17°API and Viscosity < 61cp
4		ASP	Fail	API gravity > 17°API
5	Gas Flooding	CO ₂ Miscible	Fail	API gravity > 17°API and Viscosity < 61cp
6		Nitrogen Miscible	Fail	API gravity > 17°API and Viscosity < 61cp
7		Hydrocarbon Miscible	Fail	API gravity > 17°API
8		Immiscible gas Flood	Fail	API gravity > 17°API
9	Thermal	steam Flooding	Fail	Depth < 7000ft
10		SAGD	Fail	Depth < 7000ft
11		CSS	Fail	Depth < 7000ft

Reservoir Development Options

From Table 3.3, the method that best fits the reservoir and fluid data from the Ikpeba field based on the EOR screening criteria is polymer flooding. Since the crude is low API gravity oil, one of the methods that could have been successful is the application of heat to reduce the viscosity of the crude, which enables it to flow to the surface. But thermal EOR methods are not applicable because of the depth of the reservoir. Most of the successful thermal EOR projects apply to reservoirs with a depth of less than 4000ft; but the Ikpeba field considered in this study has reservoirs located below 6000ft, with the reservoir of study (N4000) at 7200ft. For this reason, the thermal recovery methods were not considered.

The chemical methods were also screened in the EOR method evaluations. The chemical methods include polymer flooding, Surfactant flooding, ASP flooding etc. Among the chemical methods only polymer flooding

passed the screening process, while all others failed the screening process either because of the API gravity or the oil viscosity.

For this study, three development scenarios were selected for further investigation of their technical and economic feasibility. These reservoir development options included;

1. Base Case of using a vertical well to produce the heavy oil
2. Drilling of a horizontal well to produce the heavy oil
3. Polymer flooding

Dynamic Simulation

The next step of this research was to build dynamic simulation models for the selected development scenarios to check their technical feasibility in the recovery of the heavy oil from Ikpeba Field. ECLIPSE simulation software developed by Schlumberger is one of the most popular reservoir simulators in the oil industry worldwide and was adopted for this

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study. ECLIPSE Office is project manager embedded in the ECLIPSE simulator suite that was used for inputting data and displaying simulation results. The simulator suite ECLIPSE consists of two separate simulators: ECLIPSE 100, specializing in black-oil modeling, and ECLIPSE 300, specializing in compositional modeling. The black-oil, fully implicit solution method was used for this study.

Grid and properties Section

For the numerical method, the reservoir must be divided into grid cells in a spatial dimension. For each cell, the following properties must be specified: porosity, permeability, depth, thickness, etc. The grid model of the N4000 reservoir was modeled using Petrel software developed by Schlumberger. The grid and the reservoir properties (i.e., porosity, permeability and net to gross) were exported from Petrel to the ECLIPSE simulation software. The grid dimension used in this study was 64 X 49 X 10 in the X, Y and Z directions, respectively. Corner point geometry option was used to represent the reservoir.

PVT and SCAL data

This section data is related to PVT section data used in the simulator to describe the fluid properties (fluid formation volume factors, viscosities, densities, gas oil ratio, and rock and water compressibility) of each phase due to pressure changes after production or injection. The reservoir was assumed for simplicity to contain oil and water only since it is a heavy oil reservoir. The PVT data obtained for

this reservoir was incomplete, as it did not contain some data needed to carry out detailed PVT modeling with available PVT software suites. PVT correlations embedded in ECLIPSE simulation software were then used to model the PVT properties. For example, the Egboгах correlation was selected to model the viscosity of the reservoir fluid because his correlations were derived using PVT data from heavy oil reservoirs (De Ghetto et al., 1995). The reservoir fluid properties are given in Table 1.

Fluid saturation of SCAL section

The SCAL section refers to the set of rock properties which include sets of input tables of relative permeability versus saturation. Effectively, this data defines the connate (or irreducible), critical and maximum saturation of each phase; supplies information for defining the transition zone and defines the conditions of flow of phases relative to one another. The Corey's correlation was used to model the SCAL data. The reservoir rock was assumed to be water-wet, and the capillary pressure was ignored in the dynamic simulation model.

Fluid contact of the initialization section

The initial conditions are defined by specifying the OWC (Oil-Water contact) depth and the pressure at a known depth (Datum). ECLIPSE combines this data with other data from previous sections to calculate the initial hydrostatic pressure gradients in each zone of the reservoir model and allocate the initial saturation of each phase in every grid cell before production and injection.

Table 4: Equilibration data used in Ikpeba field model

Datum depth, (feet)	7126
Pressure at datum depth, (psi)	3200
Water/Oil contact depth, (ft)	7184

Polymer flooding modelling

Polymer does not reduce the interfacial tension between water and oil, but it improves volumetric sweep efficiency by increasing water viscosity. This increase in viscosity lowers mobility ratio, decreases the chances of fingering, and allows more oil to be contacted on a macroscopic scale. The polymer properties and variation of other properties such

as the RFF and adsorption were taken from different thesis works that have been published over the years and from references to different SPE publications. Some of the values and ranges of polymer properties used in this work were from the ECLIPSE simulator manual. In the Schedule Section of ECLIPSE data set, polymer concentration was set as 0.5lb/STB. The mixing parameter (ω) is used in modeling

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the degree of segregation between the water and the injected polymer solution. The Todd-Longstaff mixing parameter was set as $\omega = 1$ which signifies that the polymer solution and water was fully mixed.

Economic Analysis

After evaluating the different recovery mechanisms and field development scenarios technically, it is very important to perform an economic analysis to assess the economic feasibility of the recovery processes. In this section, the primary objective was to compare

the polymer flood to the horizontal well production in terms of economic feasibility using the net present value, internal rate of return, pay-out period, and growth rate of return and profitability index as a yardstick. The economic model used to perform this analysis was developed using Microsoft Excel.

Assumptions for economic model

To evaluate the economic analysis of the project the following assumptions (See Table 5) were made.

Table 5: Economic model Assumptions

S/N	Element	Assumption
1	Oil Price	\$55
2	Drilling of a Horizontal well	\$20MM
3	Drilling and setting of Polymer Injection well	\$22MM
4	Polymer Cost	\$ 3 per pound
5	Discount rate	10%
6	Income Tax rate	80%
7	Royalty base on a sliding scale	2.5 % of gross revenue
8	NDDC Tax	3% of CAPEX
9	Education Tax	2% of Assessable Profit
10	Variable OPEX	5 \$/bbl
11	Fixed OPEX	10% of CAPEX
12	Expensed CAPEX	30%
13	Capitalized CAPEX	70%
14	Depreciation	5 years SLD

RESULTS AND DISCUSSION

Model Grid and Properties

The grid dimensions used for this simulation were 64 X 49 X 10; with grid cell size

of 180ft by 165ft by 10ft representing X, Y and Z direction, respectively. Figure 1 shows a 3D representation of the full grid size of the reservoir of study (N4000).

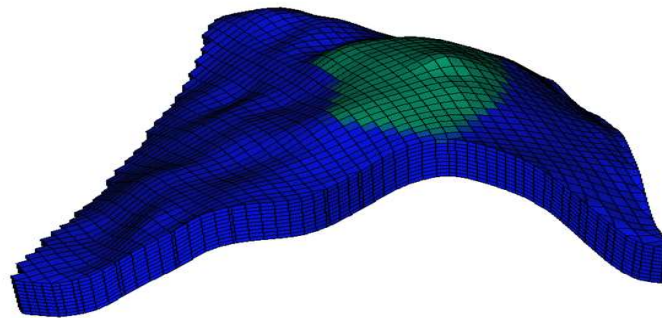


Figure 1: 3D representation of the grid system of the reservoir mode

Figure 2 shows a representation of the Net to Gross ratio (NTG) of the reservoir. It can be seen from the figure that the reservoir of

study (N4000) has a very high Net to Gross ratio, an average NTG of 0.8. Figure 3 shows a representation of the porosity distribution of the

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reservoir of study while Figure 4 shows the representation of the permeability distribution of the reservoir (N4000). It can be seen from the

figures that the reservoir of study has an average porosity value of 0.3 and an average permeability of 1600md.

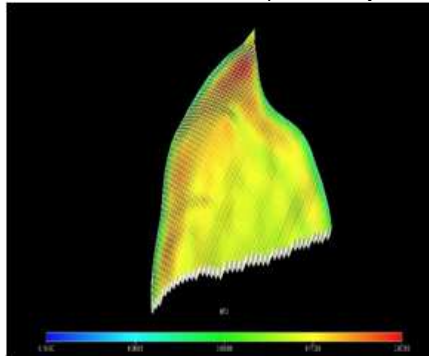


Fig 2: NTG of the reservoir

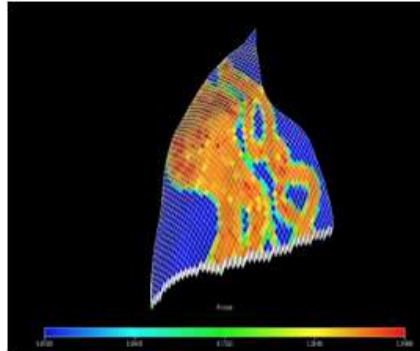


Fig 3: Porosity distribution of the reservoir

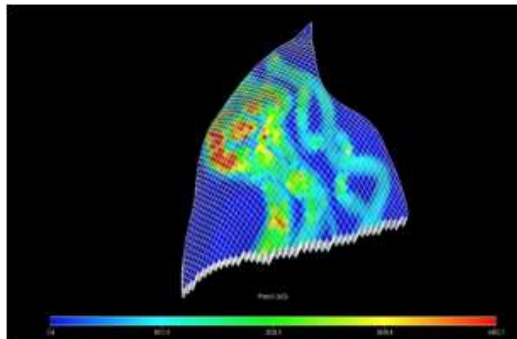


Fig 4: Permeability distribution of the reservoir

Model Initialization

Initialization of the reservoir model was performed to ascertain the initial conditions of the reservoir. The datum depth was specified as the top of sand at a depth of 7126ft with an

initial pressure of 3200psia, and the oil-water contact was specified at a depth of 7184ft. The results of the initial conditions of the reservoir are given in Table 4.1.

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Table 6: The initial conditions of the Reservoir

Oil (STB)	Water (STB)	Gas (MSCF)	Dis Gas (MSCF)	Mobile oil wrt water (STB)	Mobile oil wrt gas (STB)
30551647	304635680	2077355	2077355	11537758	13045455

Base Case Scenario

The base case scenario is a vertical well drilled into the N4000 reservoir (at grid point I = 39 and J = 15). The well was completed from Layer 1-3 in the K-direction. The well was set to produce at a controlled rate of 1000stb/day, and the simulation was set to run for 20 years.

Figure 4.5 shows the location of the well in the model while Figures 6, 7, 8, 9 and 10 show the results of the simulations for field oil recovery, cumulative field oil production, field oil production rate, field pressure and field water cut, respectively.

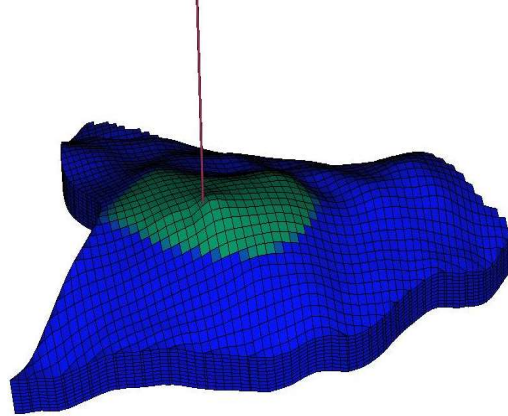


Fig 5: Location of the vertical well

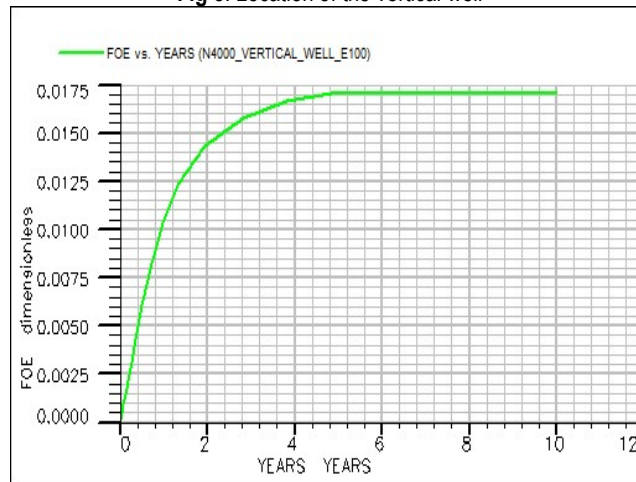


Fig 6: Field oil recovery for base case

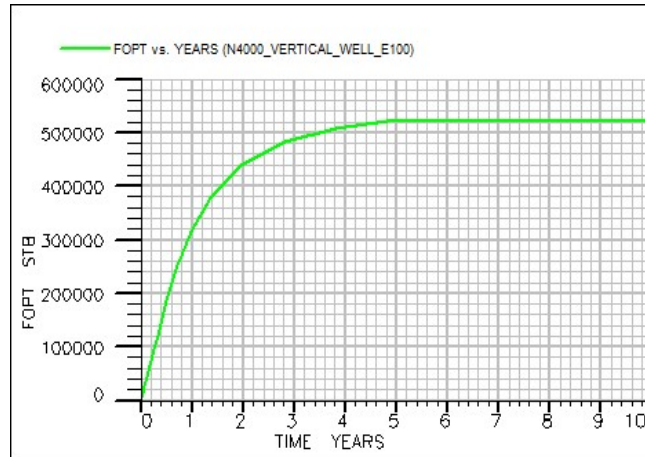


Fig 7: Base case Field cumulative oil production

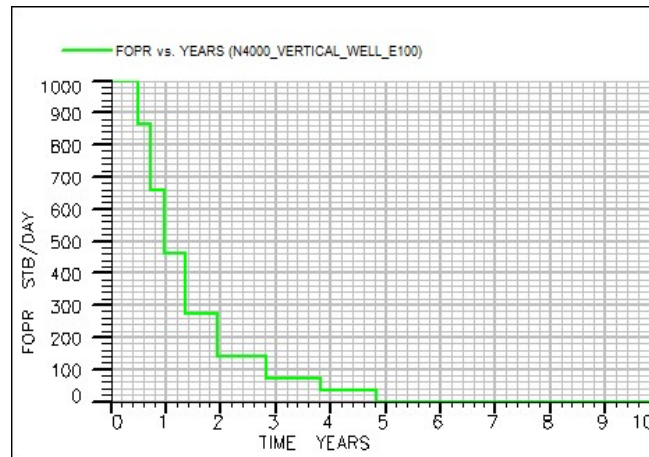


Fig 8: Field oil production rate for base case



Fig 9: Field Pressure for base case

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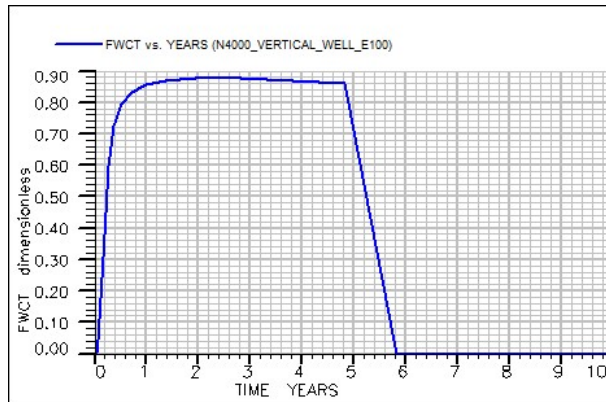


Fig 10: Field water cut for base case

The results from Figure 6, which is a plot of the total field recovery from the well, show that the total field recovery using the vertical well alone was minimal. It was about 1.7% and note that the well stopped production at the end of the 8th month of the 4th year. This very low recovery is because we are dealing with a heavy oil reservoir and from literature, the cumulative recovery from this kind of reservoir using the conventional method of production usually ranges from 1-3% of the OOIP. Figure 7 shows the cumulative field oil production using only the vertical well. The simulation results show that the cumulative field production using the vertical well only was 521468STB. As seen from Figure 8, the well was produced at the controlled rate of 1000STB/day for 6months and its rate started declining until the end of the fourth year in theeighth month, when the well could no longer produce because the field pressure had declined drastically. The field pressure is shown in Figure 9, where it can be seen that the field pressure starts from 3200 psia which is the reservoir pressure. The field pressure starts to decrease as the oil production commences which is the normal trend of production, but the pressure decline rate was rapid because it is a heavy oil reservoir and as

such much energy is needed to push the viscous fluid to the surface. The water cut as shown in Figure 10 rises from 0 to 80% within just one year. As production continues, the water cut continued to increase up to 88% when the well stopped production.

Horizontal Well Case

The second development scenario studied in this work was to drill a horizontal well into the model of the Ikpeba field. The horizontal well penetrated into the N4000 reservoir at grid point location, I=38, and J=15. The well was completed at grid point location I=38 to I=28 in the I coordinate direction and within the first layer, i.e., K=1 in the vertical coordinate direction. A sensitivity analysis was carried out to determine the optimal placement of the horizontal well and the optimal well completion, which will yield the highest oil recovery. The well was set to produce at a controlled rate of 1000stb/day, and for 20 years. Figure 11 shows the location of the well in the reservoir. Figures 12, 13, 14, 15 and 16 show the results of the simulation runs for field oil recovery, field cumulative oil production, field oil production rate, field pressure, and field water cut, respectively.

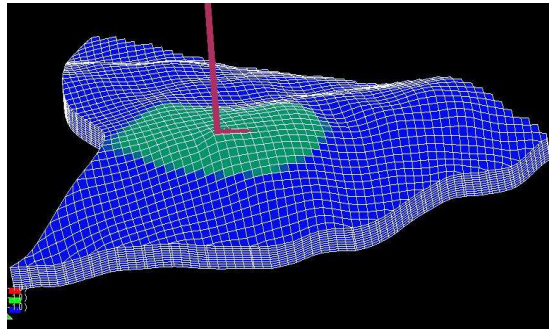


Fig 11: horizontal well Location

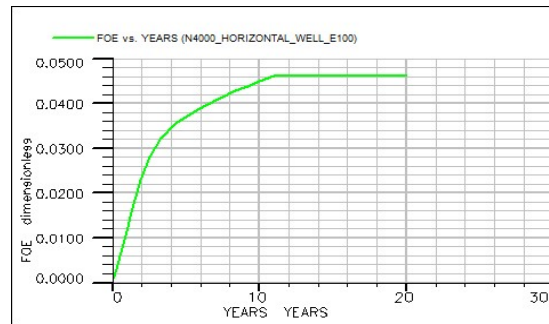


Fig 12: Oil recovery of horizontal well

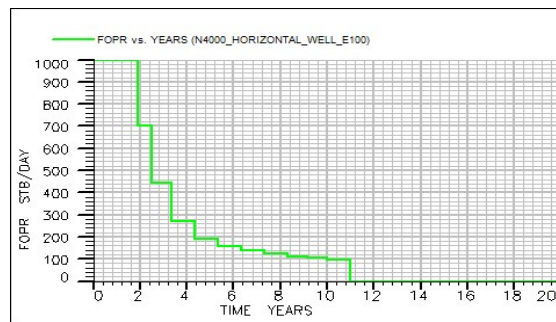


Fig 13: Oil production rate of horizontal well

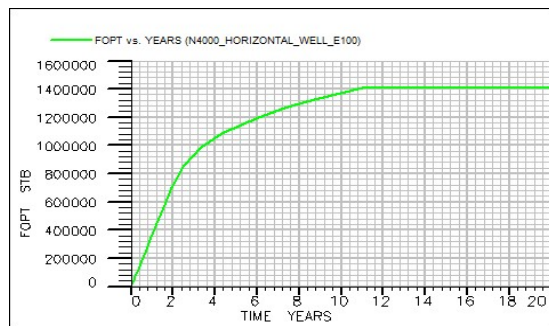


Fig14: Oil production for horizontal well

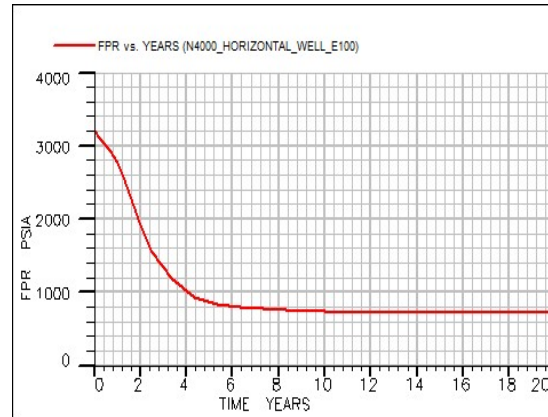


Fig 15: Field Pressure for horizontal well

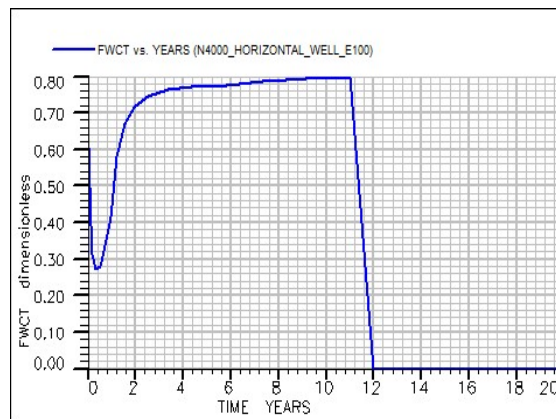


Fig 16: Field water cut for horizontal well

Figure 12 shows the total field recovery by the horizontal well was about 4.6%, and the horizontal well stopped production at the 11th year. This means that there is an additional 2.9% recovery from the reservoir with the horizontal well production when compared to the production via a vertical well. This increase in recovery is due to the large drainage area of the horizontal well. Figure 13 shows that the field cumulative oil production using the horizontal well was about 1,407,892 STB. As seen from Figure 14, the well was produced at the controlled rate of 1000STB/day for 2 years before it started to decline, until it reached the end of the eleventh year when the well could not produce any longer because the field pressure had declined. The field pressure versus time plot is shown in Figure15, where the field pressure starts from 3200psia, which is the

reservoir pressure. The field pressure starts to decline as the production starts. The water cut shown in Figure 16 started from 75% and drastically reduced to 30% within the first two months of production, and it remained at that level until the second year of production when it started to increase up to 80% at the tenth year of production.

Polymer Flooding Case

A vertical injection well was drilled in the N4000 reservoir model at location I= 32 and J=15. The base case vertical well is set as the producing well. The producing well was set to produce at a controlled rate of 1000stb/day, and the simulation was ran for 20 years. Figure 17 shows the locations of both the injection and production wells in the reservoir. Figures 18, 19 and 20 show the results of the simulation runs

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for field oil recovery, field cumulative oil production, and field oil production rate, respectively.

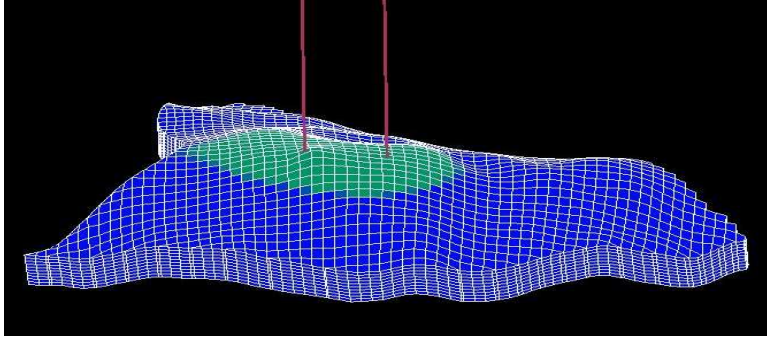


Fig 17: Location of the vertical injection well and producing well

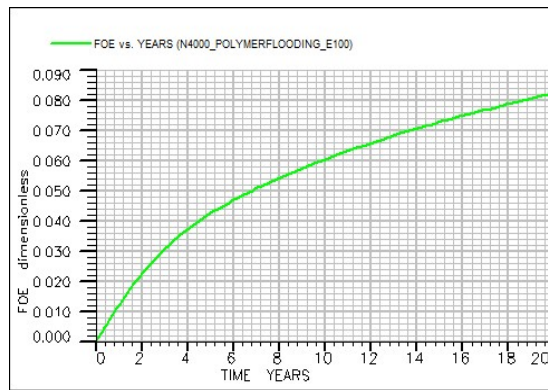


Fig 18: Field oil recovery for polymer EOR

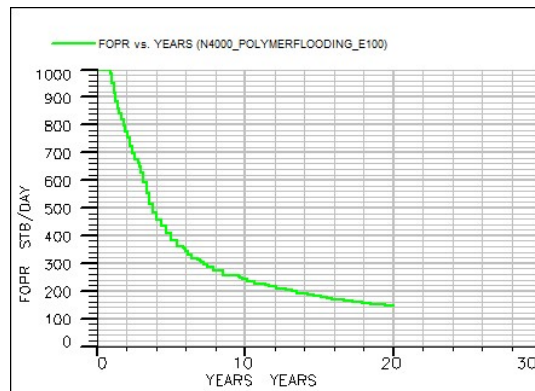


Fig 19: Field oil production rate for polymer EOR

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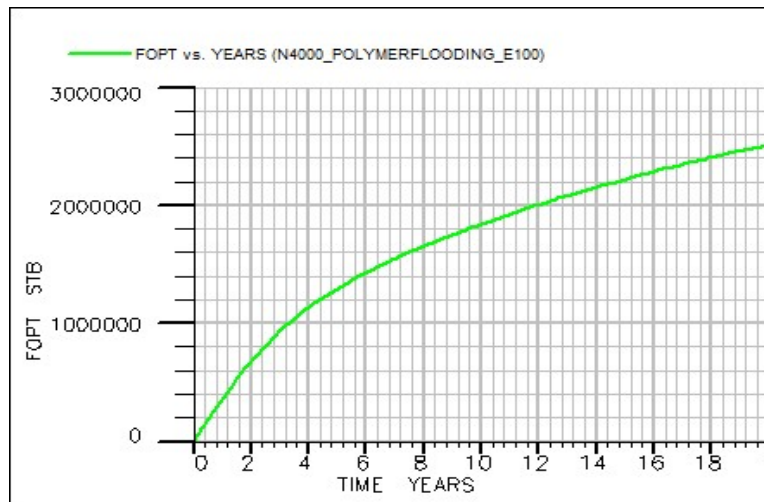


Fig 20: Field oil production rate for polymer EOR

From the results of Figure 18, which shows a plot of the total field recovery from the well, the total field recovery when polymer injection is implemented in the field for 20 years is about 8.22%. This means that there is additional recovery from the reservoir when compared to the production from two earlier cases of production using the horizontal well only and the vertical well only. Figure 19 shows the field cumulative oil production versus time when polymer injection is carried out. The simulation results show that the field cumulative oil production via polymer EOR is about 2.5 MM STB. The field was produced at the controlled rate of 1000STB/day for 5 years 8 months before it started to decline until it reached the end of the simulation run time (20 years) as seen in Figure 20, the field was producing at the rate of 145 STB/day with a minimum oil rate constraint of 50STB/day after 20 years.

Comparison of the Field Development Scenarios and Recovery Methods

Figures 21, 22, and 23 compare the field recovery, field cumulative oil production,

and field oil production rate, respectively, for the different recovery methods studied in this work. The field recovery factors from the vertical well, horizontal well, and polymer flooding are 1.7%, 4.6% and 8.22 % of the OOIP, respectively. The vertical well recovery factor is very low because of the heavy nature of the fluid in the reservoir, and it corresponds to typical recovery factors of about 1-3% of the OOIP reported in the literature for production of heavy oils. The horizontal well production data showed an incremental recovery of 2.9% (compared to the vertical well); while the polymer flooding gave the highest oil recovery with an incremental recovery of 6.52% of the OOIP, due to the large drainage area of the horizontal well accessible to the fluid. Note that the incremental recovery from the polymer flooding is due to the swept efficiency of the oil towards the producing well by the injected polymer in the aqueous phase. Table 6 shows the production and field recovery for the recovery mechanisms.

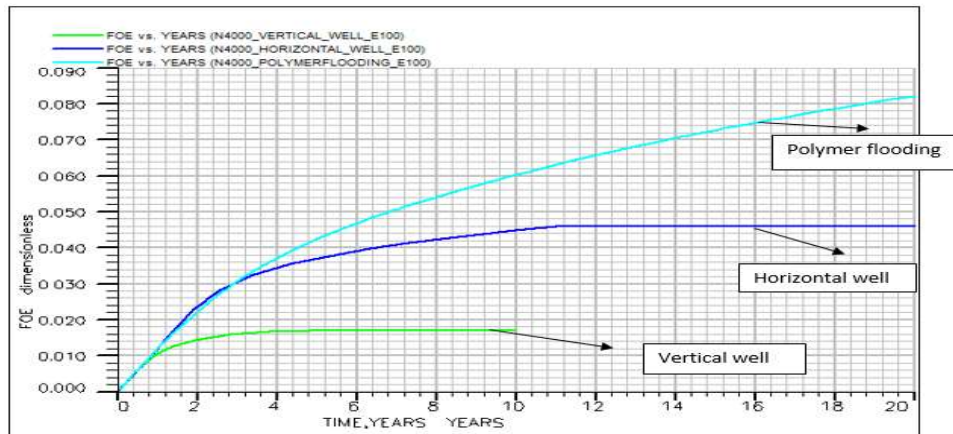


Fig 21: Comparison of the field oil recovery mechanisms

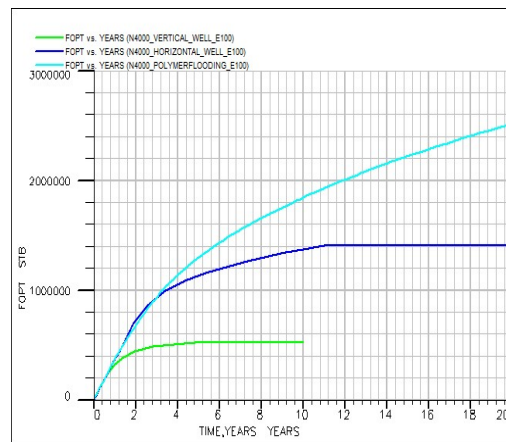


Fig 22: Comparisons of the FOPTs

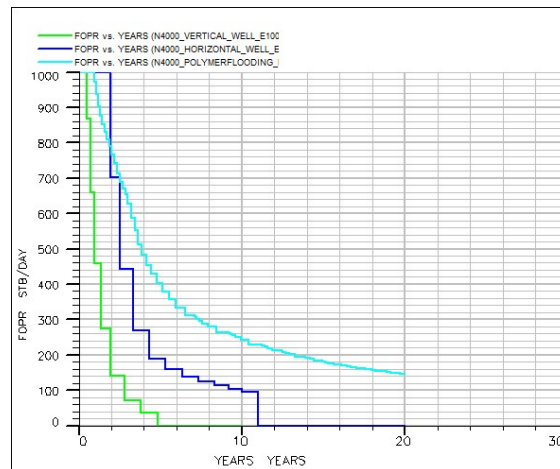


Fig 23: Comparisons of the FOPRs

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Table 7: Total field oil production and field recovery of the recovery mechanisms

Recovery Mechanism	Field oil production total (STB)	Field Recovery (% OOIP)	Incremental recovery from base case (% OOIP)
Vertical Well	521468	1.7	N/A
Horizontal well	1407892	4.6	2.9
Polymer flooding	2514020	8.22	6.52

SENSITIVITY ANALYSIS

Effect of length of the horizontal well on oil recovery

Sensitivity analysis was performed on the length of the horizontal well to see what effect it has on the oil recovery. The lengths of the horizontal well studied included 500ft, 1000ft, 1500ft and 2000ft. shows the results of

the study on the effect of the length of the horizontal well on oil recovery. From Figure 24, we observe that as the length of the horizontal well increases the recovery from the reservoir also increases, and this is because it provides more drainage area as the well is exposed to produce oil from the reservoir.

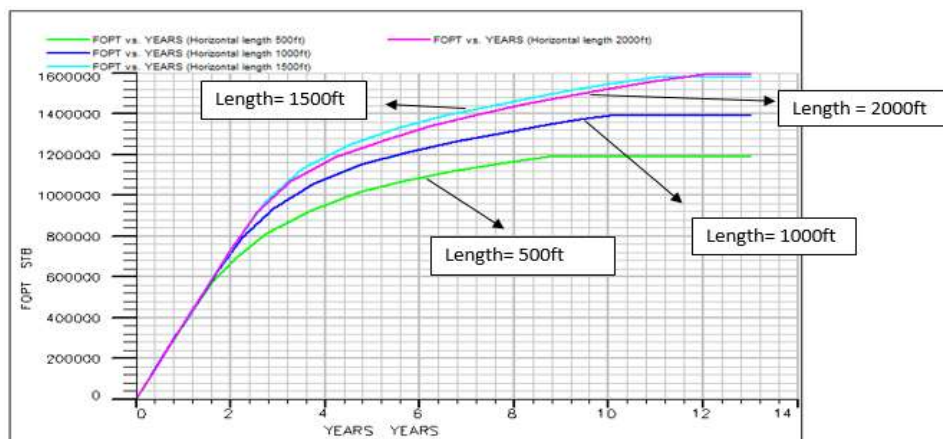


Fig 24: Effect of length of the horizontal well on oil recovery

Effect of completing the horizontal well in different layers of the reservoir

Sensitivity analysis was performed to check the effect of completing the horizontal well in different layers of the reservoir on the oil recovery. The horizontal well was completed only in the following reservoir layers at a time: Layer 1, Layer 2, Layer 3, Layer 4 and Layer 5, respectively. Note the reservoir model has 10 layers with Layer 5 located close to the oil-water contact (OWC). Figure 25 shows the effect of completing the horizontal well in different layers

of the reservoirs on oil recovery. It is noticed from Figure 25 that the well has the highest recovery when it is completed in Layer 1, and lowest recovery when the horizontal well is completed in Layer 5. The higher recovery from completion of the horizontal well in layer 1 is due to the fact that layer is further away from the oil-water contact while Layer 5 has the lowest recovery because its closer to the OWC. So, water will encroach faster into the wellbore with well completed in Layer 5 completion than in Layer 1.

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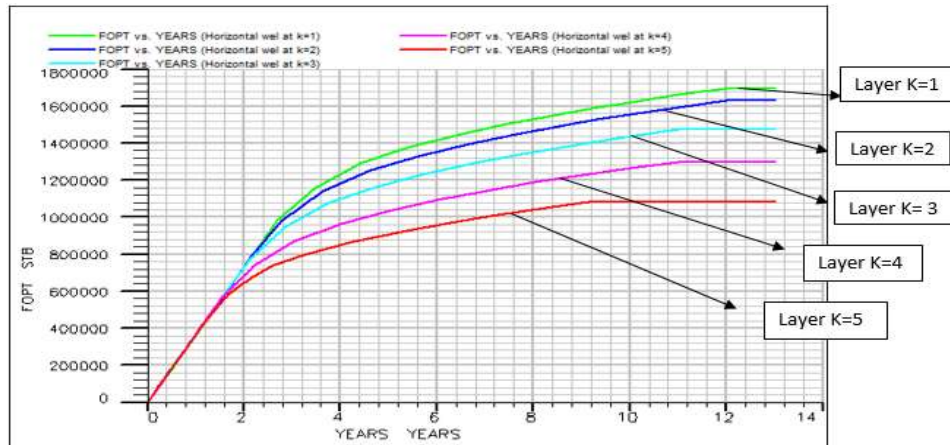


Fig 25: Effect of completing the horizontal well at different layers

ECONOMIC ANALYSIS

After evaluating the different scenarios for producing the heavy oil reservoir technically, there is a need to perform an economic evaluation of the different scenarios to ascertain which is economically viable. The economic evaluation was performed for both the horizontal well and the polymer flooding projects. An economic model was built using the oil production profiles predicted from the dynamic reservoir simulations. The model

assumed a contractual fiscal regime system and a sliding scale royalty system for a marginal field operator in Nigeria. The economic indicators used for the economic evaluation include Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI) and the Discounted Payout Period.

Tables 8 and 9 show the metrics used to measure the economic viability of the horizontal well project and the Polymer flooding project, respectively.

Table 8: Economic analysis Metrics used to measure viability of the Horizontal well project

Metrics System Measures		Host Govt. AIT \$ MM	Contractor AIT \$MM
Net Present Value @	10.00%	\$27.41	\$2.82
Internal Rate of Return			16.55%
Present Value Ratio			0.06
Profitability Index			1.06
Growth Rate of Return			10.6%
Undiscounted Take Statistics		81.4%	18.6%
Discounted Take Statistics		90.7%	9.3%
Discounted Payout Period, Years			4.51

Table 9: Economic analysis Metrics used to measure viability of the Polymer flooding Project

Metric Systems Measures		Host Govt. AIT \$ MM	Contractor AIT \$MM
Net Present Value @	10.00%	\$36.00	\$4.44
Internal Rate of Return			16.80%
Present Value Ratio			0.07
Profitability Index			1.07

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Growth Rate of Return				10.4%
Undiscounted Take Statistics			81.3%	18.7%
Discounted Take Statistics			89.0%	11.0%
Discounted Payout Period, Years				5.47

From the results shown in Table 8, it can be seen that the economic analysis of the horizontal well project using a base crude oil price of \$55 per barrel and other assumptions as earlier stated yielded the following economic indicators: NPV of \$2.82 million, an IRR of 16.55%, and a profitability Index of 1.06. The results also showed that the project would take 4.51 years before it could pay back the initial investment and start making profit.

Table 9 shows the results of the economic analysis of the polymer flooding project. Based on the crude price of \$55 per barrel, a polymer cost of \$3 per pound and other assumptions as stated in chapter three, the polymer flooding will yield an NPV of \$4.44 million, an IRR of 16.8% and a profitability Index of 1.07. The results also indicated that the project would take 5.92 years before paying

back the cost of its initial investment and start making profits.

Figures 26 and 27 show the NPV plot for the horizontal well project and polymer flooding project respectively. The horizontal well project has an NPV of \$2.82 million for the total simulation time of 11 years while the NPV of the polymer flooding (i.e., at 11 years) is \$3.42 million. This shows that the polymer flooding has a higher NPV than the horizontal well with \$60,000 (increment), which indicates the polymer flooding project is more profitable. Also note that from the payback periods, the horizontal well project will recover its money in 4.51 years while the polymer flooding project would recover its money in 5.47 years, which shows that the horizontal well project would start to make profit before the polymer flooding project.

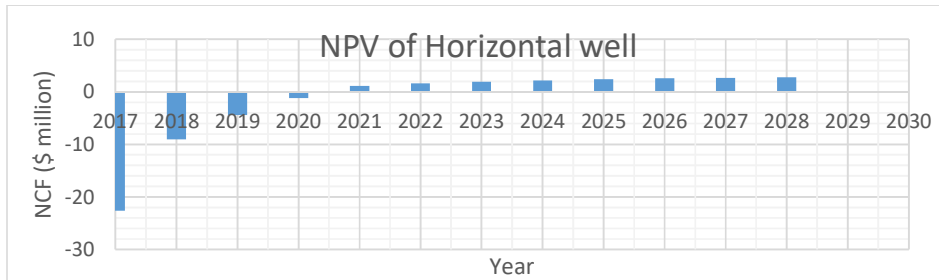


Fig 26: NPV plot for horizontal well production of heavy oil.

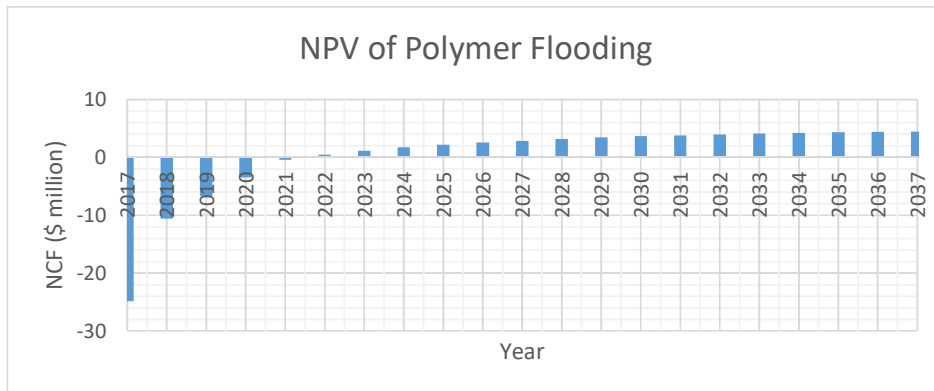


Fig 27: NPV plot for polymer flooding production of heavy oil

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With respect to the internal rate of return, the IRR is desirable or accepted when the IRR is greater than the discounted rate and rejected when the IRR is less than the discounted rate. The horizontal well has an IRR of 16.6% while the polymer flooding has an IRR of 16.8%; this shows that both projects are desirable and profitable. Growth rate of return, which is also known as the "Modified Internal Rate of Return", is said to be accepted or desirable when it is greater than the discounted rate. The horizontal well and the polymer flooding has a GRR of 10.6% and 10.4%, respectively. Both GRRs are higher than the discounted rate of 10% and as such, both projects are considered desirable.

CONCLUSIONS

1. The EOR method selected in this study for the reservoir of interest based on the reservoir rock and fluid properties was polymer flooding. The polymer flooding met all the criteria of API gravity, depth of reservoir and viscosity of the oil for application in the Ikpeba field.
2. Three development scenarios considered for producing the heavy oil from the Ikpeba field were the use of the vertical well to produce the oil; this served as the base case in this study, drilling of a horizontal well to produce the oil; and the application of polymer flooding EOR method.
3. Dynamic simulations of the three development scenarios showed that the base case of using a vertical well has a recovery factor of 1.7% of the original oil in place(OOIP); the horizontal well recovery factor was 4.6% of the OOIP and polymer flooding can recover about 8.22% of the OOIP.
4. An economic analysis of the horizontal well and polymer flooding projects show that both projects are profitable with an NPV of \$2.82 million for the horizontal well and NPV of \$3.42 million for the polymer flooding for the first 11 years. The NPV of the polymer flooding increases to \$4.44 million for a 20-year project. The discounted payback period for both the horizontal well and the polymer flooding projects is 4.5 years and 5.5 years, respectively.
5. The recommended field development strategy for producing heavy oil of the Ikpeba field is a two-prong approach. For a medium-term development strategy, a horizontal well should be drilled with an artificial lift pump installed to increase the rate of withdrawal from the reservoir. The long-term development strategy for producing the heavy oil is to initiate a polymer flooding EOR method after the natural depletion with a horizontal well.

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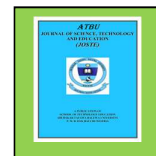
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