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Recovery of Nigerian Heavy Oil: Application of Polymer Flooding

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Abstract : *Nigeria has a lot of conventional and heavy oil resources. Although much of the conventional oil resources have been developed since independence, the heavy oil resources have remained underdeveloped due to low recovery based on primary production and consequently doubts about economic viability based on the current fiscal regime. This paper examines the application of Polymer Flood enhanced oil recovery (EOR) method to suitable Nigerian heavy oil reservoirs, seeks to develop a diagnostic model to predict the performance, evaluates the economics to determine the viability of the EOR method. The development of heavy oil will increase Nigeria's oil reserves and production. Data was collected for two heavy oil reservoirs from two oil companies in Nigeria following a Non-disclosure Agreement (NDA). The screening criteria of commercially effective EOR methods were applied to select polymer flooding for the studied reservoirs. Design of Experiment (DoE) was used to evaluate the reservoirs and operating parameters and to determine their optimum values, which were then used to predict performance using reservoir simulation. The economics of the polymer flood technique endorsed for the reservoirs considered were also evaluated using Discounted Cash Flow Analysis (DCFA). The assessments confirmed that polymer flooding technique was technically and economically viable for the studied heavy oil reservoirs. The polymer flood was observed to have a good recovery efficiency of 21%, as against the waterflooding technique which had 13% and natural depletion of 9% for the offshore reservoir. The onshore reservoir had a recovery efficiency of 9% for polymer flood, 6% for water flooding and 3.5% for natural depletion. The economic analysis showed that even at a worst-case heavy oil price of US$15, the project was viable.*

Keywords – *design of experiment, enhanced oil recovery, heavy oil, net present value, polymer flooding*

I. INTRODUCTION

1.1 BACKGROUND TO THE STUDY

Heavy oil (HO) deposits occur in more than 50 countries across the world. The global in-place resources of heavy oil are estimated to be 5.9 trillion barrels [938 billion m3], with more than 75% of these resources found in Canada, Venezuela and the United States (Briggs et al, 1988 [1]). The two most important processes that act on light oil to produce heavy oil are biodegradation (hydrocarbon oxidation process involving the microbial metabolism of various classes of compounds, which alters the oil's fluid properties and economic value) and water washing (the removal of the more water-soluble components of petroleum, especially low molecular weight aromatic hydrocarbons such as benzene, toluene, ethylbenzene and xylenes) (Palmer, 1993 [2]).

For several years, we have relied on oil and gas resources extracted from large sedimentary reservoirs (conventional oil). This has led to continuous reduction in oil and gas reserves while world energy requirements increase. Therefore, it is now crucial that we explore for oil resources in non-conventional reservoirs that contain heavy oil (HO), extra heavy oil (XHO), tar sands, oil shale and bitumen. To develop these resources requires a paradigm shift in exploration and production, compared to conventional hydrocarbons (Johnson and Dore, 2010 [3]). The rock and fluid properties of unconventional reservoirs differ significantly from those of conventional reservoirs because some non-conventional reservoirs may require stimulation methods to improve economic production rates (AER, 2015 [4]).

In addition, large quantities of heavy oil have already been discovered, thus no exploration cost is required. Most of these discoveries awaiting development are mainly onshore and at shallow depths. The cost of development wells is comparatively lower, and CAPEX profile is continuous rather than being front end loaded. EOR processes such as Cyclic Steam Stimulation (CSS), Polymer injection and Steam Flooding (SF) are well understood, and the technical and geologic risks are therefore minimized. Although heavy oil price is discounted, these advantages allow heavy oil development to compare favorably with high-risk conventional plays (Briggs et al, 1988 [5]).

1.2 Statement of the Problem

Many heavy oil fields in Nigeria are on primary production and artificial lift resulting in low recovery efficiency. So far, no heavy oil EOR method has been applied in Nigeria, despite the commercial success of several EOR methods around the world.

Most of the divested heavy oil fields in Nigeria are yet to be further developed because the operators fear that due to expected low recovery factor (RF), the fields might not be commercially viable by conventional production methods at current oil price. As a result, the technical and commercial feasibility of heavy oil development in Nigeria is yet to be fully evaluated.

Nigeria has a national target to increase oil production to 3 MM BOPD and reserves to 40 billion bbls by 2020. This can be achieved if the HO fields are also matured and developed in addition to the light oil fields.

To develop the HO fields, EOR methods are required. The challenge is how do we determine what EOR method to apply for a given field or reservoir, and what the recovery efficiency would be.

The Niger Delta has about 10 billion bbls of HO in place (BP Statistical Review, 2011 [6]). However, for the purpose of this study, some Nigerian HO reservoirs will be used as case study. These are sandstone reservoirs with oil of API gravities ranging from 15-22^0.

Based on the data received from two operating companies in Nigeria, two reservoirs, one offshore and one onshore (A and B respectively) were used to study the application of polymer flooding EOR in Nigeria. Reservoir A will be used to establish a baseline, and the derivations therefrom will be applied to Reservoir B. These reservoirs will be modelled for performance prediction and economic analysis.

II. LITERATURE REVIEW

2.1 Global Outlook for Heavy Oil

There are HO and XHO deposits in over 35 countries of the world (Fig. 2.1), with the largest deposits in Canada and Venezuela (Dusseault, 2008 [7]; Meyer, 2007 [8]).

The International Energy Agency (IEA, 2010 [9]) projects a global primary energy demand rate of about 300 MM BOE/D in its world energy outlook for 2008-2035. From its current share of about 30%, the demand for crude oil is expected to increase to about 100 MM BOE/D in 2035. However, 27 years from the start of this projection, production from conventional oil sources is expected to peak at about 70 MM BOE/D leaving some 30 MM BOE/D oil supply gap to be partly filled by heavy oil sources. With the projected significance of HO to future energy supply, one can understand why this non-conventional resource continues to attract the attention of energy developers and policy makers (Lee, 2009 [10]).

The increasing interest in HO is based on 3 main factors: 1. That estimated global reserves are more than half those of conventional oil. 2. That the rate of depletion of conventional oil far exceeds the rate at which they are discovered or produced and 3. It is necessary to develop cost-effective technologies to exploit HO in anticipation of unprecedented energy demand in near future (Bagci, 2007 [11]). Moreover, favorable oil prices from supply viewpoint will encourage the application of EOR methods for the exploitation of HO, as seen with the Alberta tar sands which was previously a 'neglected' resource but is now a key component in the global energy mix due to the favorable economic condition in place for EOR applications.

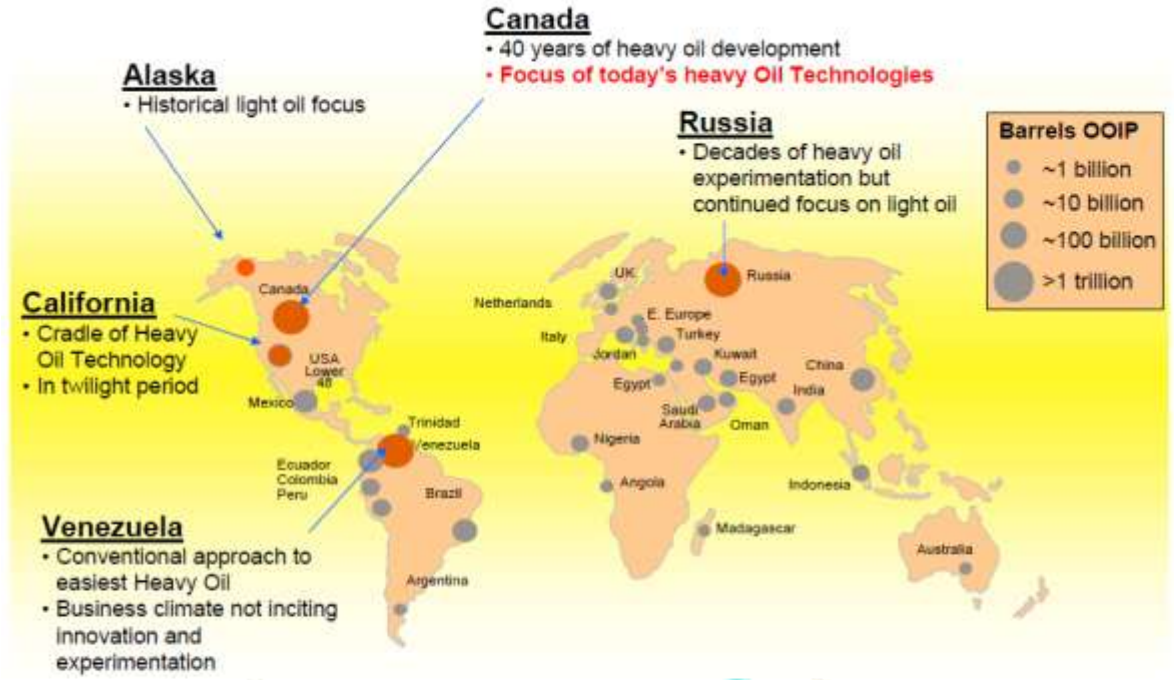

Figure 1. Evolution of Heavy Oil Resources development in the World (Source: JPT, IEA, SLB OFS Marketing)

In terms of global unconventional resources, Athabasca tar sands deposit is the world's largest petroleum resource with about 1.3 trillion barrels in the ground while the Orinoco field is the largest HO resource in the world with about 1.2 trillion barrels (USGS, October 2009 [12]). About 15% of world oil resources is heavy oil (see Fig. 2). Extra heavy oil is about 25%, oil sands and bitumen constitute 30% while conventional oil is about 30% (Faegestad, 2016 [13]). Currently, about 90% of oil production around the world is from conventional oil. Over 35% of world heavy oil resources are in Venezuela and Canada. Canada has over 40 years of heavy oil development and is the focus of today's heavy oil development. California is a hub of heavy oil development. (Briggs et al, 1988 [14]).

Nigeria has over 10 billion barrels (OOIP) of heavy oil (BP Statistical Review, 2011 [15]). In recent times, global production of HO constitutes about 6% of total oil production of about 84 MMBOPD (Farouq, 2007 [16]), but has increased to about 10% (Trevisan et al., 2009 [17]) and is expected to increase in the long term.

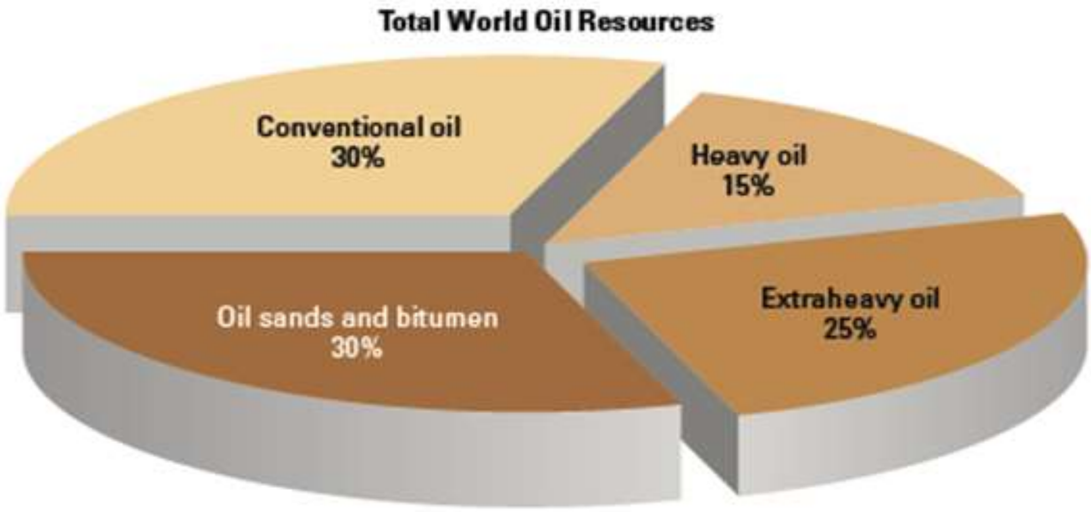

Figure 2 World oil resources by percentage distribution (Source: Schlumberger Oilfield Review, 2016)

2.1.1 Heavy Oil Resources in Nigeria

Nigeria has about 10 billion bbls in place of heavy oil (see Fig. 1). There are over 50 heavy oil reservoirs in Nigeria, with total reserves of over 2 billion barrels (DPR). Some of the Heavy Oil reservoirs and the field containing them include those shown in Table 2.1.

Most of the fields in Table 2.1 were divested by Shell Petroleum Development Company (SPDC) to marginal fields and indigenous operators (Heritage Energy, First Hydrocarbon, Shoreline Natural Resources, Neconde, etc) some of which are now in Joint Venture with Nigerian Petroleum Development Company (NPDC). Shell Nigeria Exploration & Production Company (SNEPCO) did not include R-670 (a heavy oil reservoir in Bonga Southwest Aparo with API of 19.2) in their proposed field development plan for Bonga SW Aparo. The volume in place for this reservoir is about 608 MMSTB. We think the reason is because the reservoir did not meet the economic criteria for development by the Company based on primary production assessment.

Most of the heavy oil fields in Table 1 are yet to be further developed since divestment because the operators are yet to establish that the development will be commercially viable especially due to fall in oil price in recent times and the property of the oil in question. In Nigeria, so far, although conventional production with horizontal wells is used for heavy oil development, there is a dearth of publication on the suitable application of HO recovery processes in the Niger Delta. This work intends to contribute towards addressing that gap and thus explore options for HO development in Nigeria by using a case study of some reservoirs.

Table 1. Some Nigerian Heavy Oil Reservoirs (Source: DPR)

S/N	Field	Reservoir	API	Viscosity (cP)	Temp (F)	Terrain
1.	Ofa	N4000X	13.5	62.7	152	Onshore
2.	Ofa	N3500X	15.6	38.3	151	Onshore
3.	Ofa	M8600X	15.9	38.8	147	Onshore
4.	Ofa	M8800X	15.9	37.9	148	Onshore
5.	Ofa	N1000X	15.9	38.0	148	Onshore
6.	Ofa	N2000X	15.9	37.1	149	Onshore
7.	Ughelli East	K6000X	15.9	15.6	135	Onshore
8.	Oweh	O5300X	16.4	16.6	127	Onshore
9.	Ogini	D5200X	16.7	22.0	134	Onshore
10.	Ogini	D6000X	16.7	21.0	135	Onshore
11.	Kokori	K7000X	16.8	110.0	131	Onshore
12.	Kokori	K7100X	16.8	110.0	131	Onshore

13.	Biseni	D1400X	17.0	26.6	140	Onshore
14.	Olomoro-Oleh	O7500X	17.1	33.0	135	Onshore
15.	Ibigwe	B4000X	17.4	28.1	110	Onshore
16.	Kokori	K6000X	17.4	110.0	124	Onshore
17.	Kokori	K8000X	17.4	110.0	135	Onshore
18.	Olomoro-Oleh	O7000X	17.4	25.8	133	Onshore
19.	Ekulama	D4000E	17.7	30.6	130	Onshore
20.	Ekulama	D5000A	17.7	21.9	130	Onshore
21.	Afiesere	J3100X	17.9	40.0	122	Onshore
22.	Afiesere	O4000X	17.9	40.0	122	Onshore
23.	Sapele	C5300X	19.5	35.5	140	Onshore
24.	Sapele	B1700X	20.0	42.1	109	Onshore
25.	Sapele	B4100X	20.1	38.8	120	Onshore
26.	Ekulama	E5000A	20.3	308.0	140	Onshore
27.	Mosogar	U2000X	20.3	19.5	117	Onshore
28.	Sapele	B2700W	20.3	32.3	117	Onshore
29.	Sapele	B3600	20.6	27.4	119	Onshore
30.	Ebok	LD-IB	15.1	540.0	110	Offshore
31.	Bonga	R670	19.2			Offshore

2.1.2 Characteristics and Properties of Heavy Oil

Heavy Oil is defined as crude oil that has API gravity of 10-20^o (USGS, 2007 [18]; API), API gravity of 10-22^0 (Brazilian ANP) or viscosity>10cP (Faegestad, 2016 [19]), but the World Petroleum Congress (WPC) defines it as crude oil with API gravity of 10-22.3^0 or density above 0.920 g/cm^3 (Briggs et al, 1988 [20]), while those with API gravity less than 10^0 are XHO. However, the flow properties of HO and thus its potential productivity is better represented by its viscosity which has a more direct relationship with temperature than API gravity. Therefore, in the petroleum industry, most definitions refer to in-situ viscosity (Head et al, 2003 [21]; Gibson, 1982 [22]). The United Nations Institute for Training & Research defines HO as gas free oil at viscosity of 100-10,000 cP and density of 0.934 -1.000 g/cm^3 at standard conditions (UNITAR, 1982 [23]).

However, it is important to note that certain oil may not always simultaneously meet the criteria of specific gravity and viscosity to be classified as heavy. This is because, although the API gravity is related to the specific gravity, there is no straightforward relationship between viscosity and specific gravity. Therefore, a strict global definition of HO does not exist at the moment (Trevisan, 2009 [24]). In any case, viscosity may serve as a better yardstick as it controls the ability to flow.

Therefore, we shall classify heavy oil based on viscosity (10-1,000 cP) and API gravity (10-22.3^0) at initial reservoir conditions. Heavy oil has higher carbon to hydrogen ratio along with a high amount of carbon residue, asphaltene, sulphur and metal compounds compared to conventional oils. The quantity of lighter ends is smaller, resulting in lower market value.

The low mobility of HO at in-situ condition prevents reliance on natural drive mechanism for its extraction. In addition, the deployment of secondary recovery techniques, such as water and gas injection, is not very feasible due to poor microscopic and areal sweep efficiencies. Therefore, exploitation of HO requires the application of Enhanced Oil Recovery (EOR) techniques which reduce capillary and viscous forces, thereby improving recovery efficiency. Some efficient EOR methods of producing HO require enthalpy input into the reservoir by hot fluid injection or addition/creation of heat in the reservoir. As reservoir temperature increases, viscosity of HO decreases, and the flowrate increases due to increase in mobility. To develop HO projects require that we choose technology that is effective with improved recovery efficiency based on the characteristics of the reservoir. Strategically, the focus is to optimize available EOR techniques while searching for better alternatives. The choice of EOR method for use in a specific reservoir however depends on many criteria including technical, economic and environmental. Therefore, the selection of a suitable exploitation method requires thorough studies.

There are significant HO reserves in Nigeria, but the industry must exploit them using proven EOR methods in a cost effective, safe, and environmentally friendly manner.

2.2 Theoretical Framework

A combination of increasing energy demand, declining performance of conventional oil fields and attractive oil prices is the driver for the interest in HO resources and the methods for developing them. However, due to the low mobility of HO, it is not feasible to rely on primary production techniques (natural drive mechanism) for their recovery. Conventional secondary recovery methods like water flooding are not reliable either for the exploitation of HO due to poor microscopic and macroscopic efficiency (Farouq, 2007 (26); Trevisan et al., 2009 [25]; Bata et al., 2018 [26]).

While microscopic transport properties like relative permeability and capillary pressure are responsible for conventional displacement, HO recovery requires the use of Enhanced Oil Recovery (EOR) methods which reduces viscous and capillary effects to achieve significant impact on recovery efficiency. EOR introduces what was not originally in the reservoir, and generally refers to methods applied to reduce the residual oil saturation, usually after primary and secondary recovery, but can be applied directly to heavy oil reservoirs. The performance of an EOR method is measured by the amount of additional oil that can be economically recovered in relation to that obtained by conventional methods.

The recovery of heavy oil is challenging due to its high viscosity, and the fact that reservoirs with such oil do not respond significantly to conventional recovery techniques under primary and secondary methods. HO recovery requires different enhanced oil recovery (EOR) techniques depending on the fluid properties and the characteristics of the reservoir containing the oil. The rheological properties of HO and the characteristics of their reservoirs make its production a challenge in the oil industry. Fig. 3 below shows typical recovery factors. The figure shows that for light oil reservoirs, primary and secondary methods can recover 25% and 30% while EOR can recover 45%. For a heavy oil reservoir, primary and secondary methods can recover 5% each while EOR can recover 90%. For tar sands, recovery is only by EOR as primary and secondary recovery methods are not feasible.

The total world oil production from EOR in 1998 was about 2.2 MM BOPD, out of which about 43% (1 MM BOPD) is HO with steam flooding accounting for 36% of that. There were about 208 EOR projects for HO production in 1998, out of which 178 were steam projects. The single largest steam flood in the world was in the Duri HO field in Indonesia which produces about 300,000 BOPD. Five EOR schemes have had commercial success. These are steam flood and soak, hot waterflood, In-situ Combustion, polymer and immiscible CO_2. Thermal methods, especially steam flooding have proven to be the most successful (Meyer, 1998 [27]). By 2006, the total oil production from EOR has increased. The distribution is shown in Fig. 4

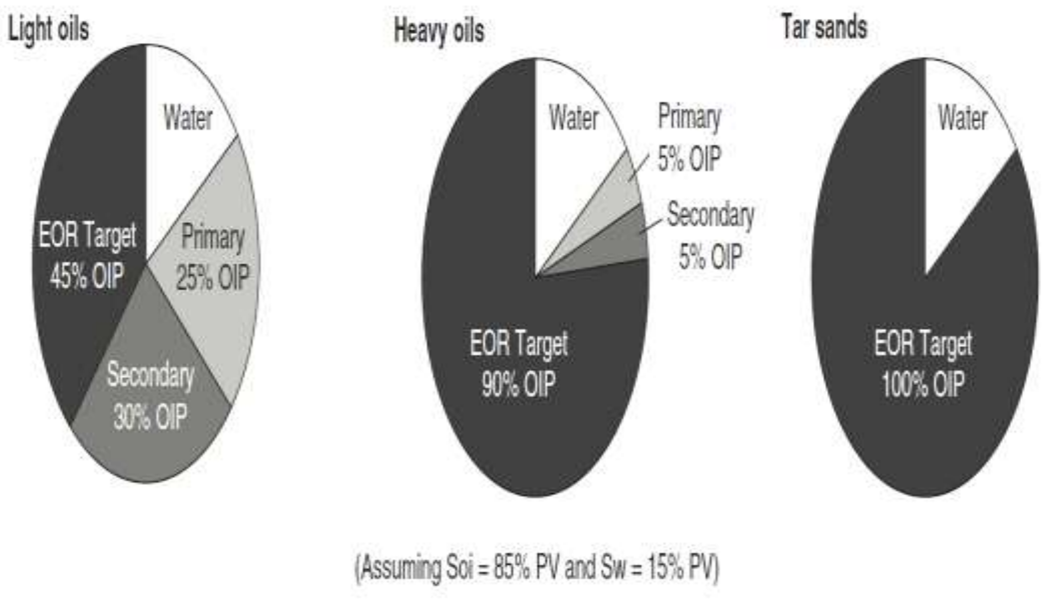

Figure 3 EOR targets for different hydrocarbons (Thomas, 2008).

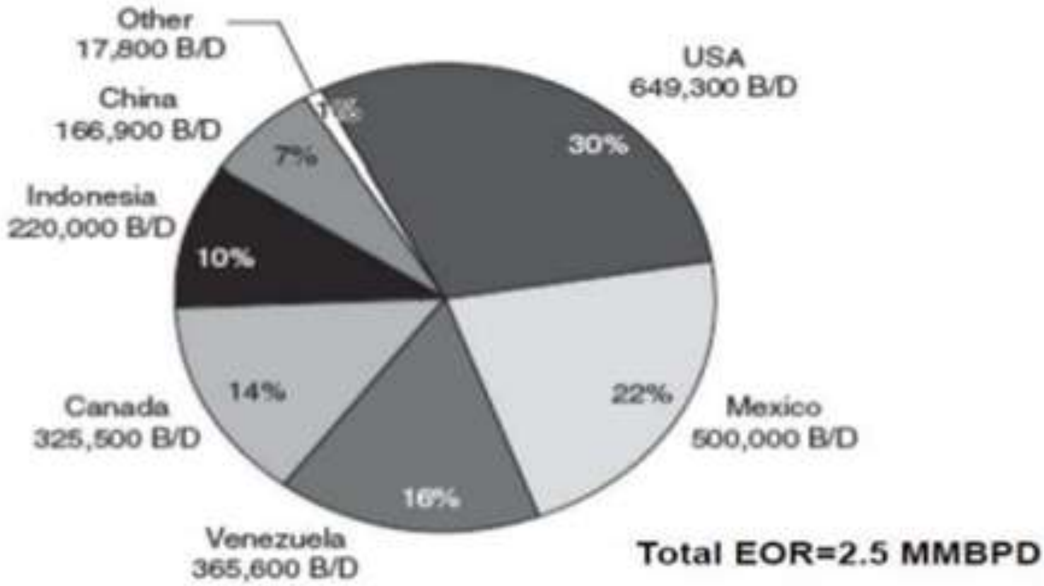

Figure 4 Worldwide EOR (Thomas, 2008)

2.3 Some Technical Options for Heavy Oil Recovery

HO reservoirs that meet certain characteristics will require certain recovery methods. Options for HO recovery include the use of thermal, and non-thermal methods. Non-thermal methods include the use of chemical effects and phase behavior to reduce or eliminate the capillary forces trapping the oil, dilute it or alter its mobility. The key is to reduce the oil saturation which can be achieved by reducing the viscosity, unfavorable mobility and interfacial tension. Some of the methods are shown in Fig. 5. However, this study is focused on Polymer Flooding which is a non-thermal EOR method.

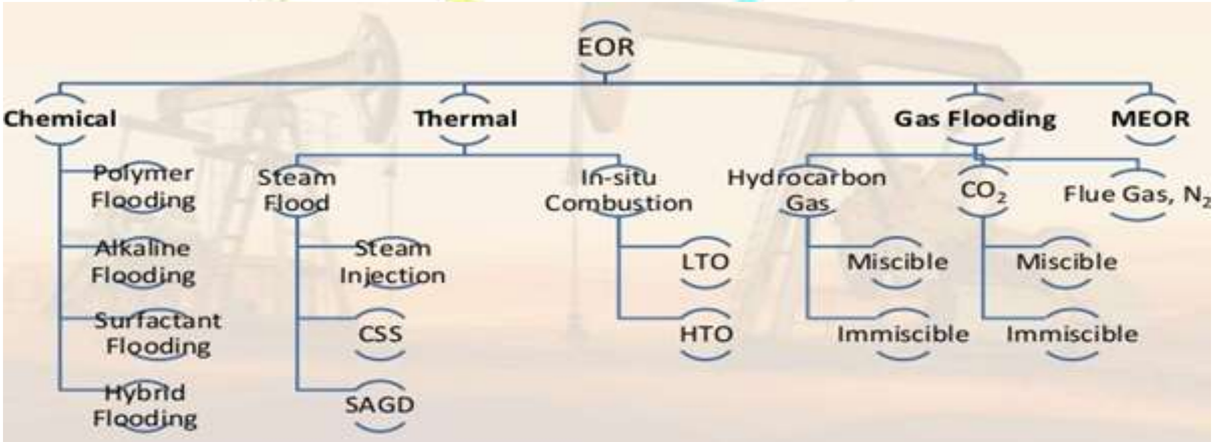

Figure 5 Classification of EOR (oges.info)

2.3.1 Non-Thermal EOR Methods

While thermal recovery methods are proven technologies, they are not suitable for some classes of reservoirs, like those with low permeability (< 1D), thin pay (< 9m), moderate viscosity (<1,000cP), deeper reservoirs (>900m), in addition to the environmental challenges (Farouq et al, 2007 [28]).

Basically, most non-thermal EOR methods are hinged on improving the mobility ratio in favour of oil. For example, solvent addition could reduce oil viscosity while increasing that of the displacing fluid, or lower interfacial tension. Non-thermal EOR methods include Cold Heavy Oil Production with Sand (CHOPS), water flooding, Vapor Assisted Petroleum Extraction (VAPEX), Chemical Flooding, Microbial EOR and Miscible Displacement.

2.3.2. Chemical Flooding

Chemical Flooding comprises of the injection processes that use chemical solutions as displacing fluids. These solutions are alkali, surfactants, and polymer (Donaldson, et al, 1985 [29]), and they basically reduce capillary effect by lowering interfacial tension or by improving the mobility ratio.

2.3.2.1 Polymer Flooding

Polymer flooding is a modification of the water injection method in that a high molecular weight polymer is added to the water before being injected into the reservoir. This improves the mobility ratio and results in a more efficient sweep than is achieved using conventional water injection. The main objective of polymer injection during water flooding of oil reservoirs is to decrease the mobility of the injected water. This decrease results in a more favourable fractional flow curve for the injected water, leading to a more efficient sweep pattern and reduced viscous fingering. Certain plugging effects within highly permeable layers may also occur and result in the diversion of the injected water into less permeable zones of the reservoir.

The decrease in mobility of the injected water resulting from the addition of polymer is due to two effects. Firstly, the viscosity of the polymer solution is higher than that of pure water (the viscosity of the polymer solution increases as the concentration of the polymer in the water increases). Secondly, the rock permeability to water is reduced after the passage of a polymer solution through the rock material (the permeability to oil is, however, largely unaffected). Both effects combine to reduce the value of the water mobility while that for the oil is unaltered. (Eclipse Technical Description, 2013 [30]).

It was reported that polymer flooding was successful at Taber South in Canada and at Huntington Beach California. Twenty-two (22) polymer flood projects, out of which 5 were for HO were listed following a survey conducted by The Oil & Gas Journal (2000) [31]. Polymer flooding is most effective when applied during the early life of the reservoir, especially when applied to improve water flood performance. However, the process is very expensive for HO systems. The major limitations in using polymer flooding are the adsorption of polymer onto the reservoir rock, polymer degradation and injectivity loss (Santos et al., 2014 [32]). Polyacrylamides and polysaccharides are the polymers often used in EOR operations, as they present better efficiency in improving mobility ratio and reducing permeability. Hydrolyzed Polyacrylamide (HPAM) is one of the most commonly used (Thomas, 2008 [33]).

2.4 Review of Some Technical Studies

Taber (1983) [34] presented some technical screening criteria which also have some economic considerations along with the basic recovery mechanism that limit the success of each EOR method. The technical guides were based on laboratory data and results of EOR trials. He discovered that some criteria depend on oil properties while others depend on reservoir characteristics. He proposed that since the implementation of EOR projects are expensive, time consuming and people intensive, the first step is to select a reservoir that has sufficient recoverable oil and areal extent to make the venture profitable. This guide has been useful and have been used in EOR candidate selection. He summarized his findings in Table 2.

Table 2 Screening Criteria (Source: Taber, 1983)

Oil Properties				Reservoir Characteristics					
	Gravity (^{o} API)	Viscosity (cP)	Composition	Oil Saturation	Formation type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (^{o}F)
Gas Injection Methods									

Hydrocarbon	>35	<10	High % of C2-C7	>30% PV	Sandstone or Carbonate	Thin unless dipping	NC	>2,000 (LPG) to >5,000 (HP Gas)	NC
Nitrogen and Flue Gas	>24, >35 for N2	<10	High % of C1-C7	>30% PV	Sandstone or Carbonate	Thin unless dipping	NC	>4,500	NC
Carbon Dioxide	>26	<15	High % of C5-C12	>30% PV	Sandstone or Carbonate	Thin unless dipping	NC	>2,000	NC
Chemical Flooding									
Surfactant/ Polymer	>25	<30	Light intermediate desired	>30% PV	Sandstone preferred	>10	>20	<8,000	<175
Polymer	>25	<150	NC	>10%PV Mobile oil	Sandstone preferred; carbonate possible	NC	>10	<9,000	<200
Alkaline	13-35	<200	Some organic acids	Above waterflood residual	Sandstone preferred	NC	>20	<9,000	<200
Thermal									
Combustion	10-25 normally	<1,000	Some asphaltic components	>40-50% PV	Sand or sandstone with high porosity	>10	>100*	>500	>150 preferred
Steam Flooding	<25	>20	NC	>40-50% PV	Sand or sandstone with high porosity	>20	>200**	300-5,000	NC

NC = not critical, * transmissibility > 20md-ft/cP, ** transmissibility > 100 md-ft/cP

Ridha (2000) [35] developed an expert system for selecting and designing EOR processes by using an Artificial Intelligence (AI) technique. It was a good job as the AI also prepared appropriate input data file for the simulator. Other works include the Maestro software by RPS group which is a powerful EOR screening and optimization tool.

Oskui et al, (2009) [36] did some work on screening potential production technologies for the Lower Fars in Kuwait. He explored various methods of heavy oil production technology to determine a suitable EOR method for the Lower Fars, and then did some performance prediction after choosing some thermal methods. That work provided a basis for EOR in the Lower Fars in Kuwait.
Donaldson (1985) [37] also developed a screening guide for EOR which is summarized in the Table 3.

Table 3. Screening Parameters for some EOR Methods (Adapted from Donaldson, 1985)

Screening Parameters	Steam injection	*In-situ* combustion	CO_2 Flood	Surfactant-polymer	Polymer	Alkaline Waterflood	Hydrocarbon Miscible
1. Oil viscosity, cP	n.c.	n.c.	< 12	< 20	< 200	< 200	< 5
2. Oil gravity, API	10-25	10-45	> 30	< 25	> 18	15-35	> 30
3. Depth, ft	200-5000	> 500	> 2300	< 8500	< 8500	n.c.	n.c.
4. Reservoir temperature, °F	n.c.	n.c.	n.c.	< 250	< 200	< 200	n.c.
5. Initial reservoir pressure, psig	n.c.	n.c.	> 1200	n.c.	n.c	n.c.	n.c.
6. Net pay, ft	> 20	> 10	n.c.	n.c.	n.c	n.c.	n.c.
7. Permeability, md	n.c.	n.c.	n.c.	> 20	> 20	> 50	n.c.
8. Residual oil saturation, %	50	50	25	> 25	> 50	> 25	> 25
9. Transmissibility, md ft/cp	> 100	> 20	n.c.	n.c.	n.c.	n.c.	n.c.
10. Porosity, %	> 10	> 10	n.c.	n.c.	n.c.	n.c.	n.c.
11. Salinity (TDS), ppm	n.c.	n.c.	n.c.	< 50,000	n.c.	< 2500	n.c.
12. Hardness (Ca and Mg)	n.c.	n.c.	n.c.	< 1000	n.c.	-	n.c.
13. Operating pressure, psi	< 2500	n.c.	> 1100	n.c.	n.c.	n.c.	> 1300
14. Target oil, bbl/acre-ft	> 500	> 400	n.c	n.c.	n.c.	n.c.	n.c.
15. Lithology	n.c.	n.c.	n.c	Sandstone	n.c.	Sandstone	n.c.
16. Well spacing	< 10	< 20	n.c	n.c	n.c	n.c	n.c

Some progress has been made in polymer flooding for HO recovery since 1977 following some laboratory, field tests and pilots that have been conducted around the world.

In 1977, two scientists, Knight and Rhudy at Marathon Oil Company started research on heavy oil recovery using polymer (Knight and Rhudy, 1977 [38]). They injected partially hydrolyzed polyacrylamide (HPAM) into sand packs of permeability 3,700 – 5,900 mD and porosity 35%. One of the sand packs had a viscosity of 220 cP and API of 19.8^o. The other had a viscosity of 1,140 cP. The test results were good, giving a recovery of 19-31%, which shows the potential of polymer flood in heavy oil recovery.

A team of researchers in Western Canada injected polymer solutions of about 1,500ppm to displace 3 oil samples of 280, 1600 & 780 cP (Wassmuth et al., 2007 [39]) into high permeability cores starting with 0.5 PV of water, then 6PV of polymer solution and then 5PV of water. The polymer produced an in-situ viscosity of about 18 cP and resulted in an incremental recovery of 16, 22 and 23% for the 3 samples, respectively.

Asghari and Nakutnyy (2008) [40]) showed that PAM concentrations of >5,000ppm is required to mobilize heavy oil of viscosity 1,400 cP when tested with 2 sand packs of permeability 2 & 13 D.

Wang and Dong (2009) [41] showed that polymer solution must exceed a certain effective viscosity to achieve a recovery of >10%. Polymer flooding was conducted on a single well as a pilot case in Bohai bay offshore China in 2002 for 500 days. The result was favourable; a drop-in water cut from 95 – 54% and an incremental production of about 157,000 bbl of oil. Following the success of the pilot, polymer was injected into 4 injection wells with 6 corresponding oil producers in 2005. The result was about 111,330 bbl of oil production and a 10% drop in water cut (Han et al 2006 [42]). Bohai had poor consolidated sands of 25-35% porosity, permeability of 2.6D. The reservoirs are at depths of 1,300 – 1,600m with an average thickness of 61.5m.

Polymer injection was successful at the Bati Rahman field in Turkey. The oil gravity was 10-15^o API. Primary production yielded only 1% recovery. CO_2 flooding improved the recovery to 5%. They decided to inject 10,000 bbl of polymer solution into each well, then shut in for a week, and resume CO_2 flooding. After 3 weeks of injection, there was increased production in 16 wells. The cost of the polymer was US$445,000 but the payout period was 1 year (Topguder, 2010 [43]).

The Kalata formation in Marmul field in Southern Oman has a medium heavy oil with viscosity of about 80-110 cP. It is about 2,001 ft deep at a temperature of 46^{o}C. They first ran a pilot with 1 injector and 4 producers from 1986-1988. The injector was for polymer solution. A 1,000-ppm solution of PAM was injected at 1,345 bpd which gave 15 cP at surface. Water was first injected pre-flush (0.23PV), then the polymer slug (0.63PV), and then a 0.34PV of water post-flush from May 1986-January 1988. The result was 12% recovery at the end of water pre-flush, 46% recovery at the end of polymer flood and 59% at the end of water post-flush (Koning et al, 1988 [44]). Following the pilot, PDO has started a large-scale polymer flood in Southern Oman to maintain production levels as fields mature. PDO estimates an increase in at least 20% recovery from the heavy oil reservoirs if polymer flooding is used.

There are some challenges with polymer flooding. These include how to maintain a good polymer viscosity, and this is affected by water salinity, shear degradation, thermal degradation, adsorption by the rock. Others are low injectivity, plugging of formations, etc.

Thomas (2008) [45] showed that in order to achieve good result with polymer flooding, the technique should be applied early, well before the residual oil saturation is reached. Wang et al. (2009) [46] showed that the salinity of the water is a very important factor in polymer flooding. The lower the salinity, the better the recovery. Field test at Daqing field in China showed that adjacent areas with 600 ppm water salinity recovered more than the test area with 3,800 ppm when used to prepare polymer solution for flooding. This was supported by test results from Dalia field in offshore Angola with viscosity of PAM showing a decrease with increase in water salinity (Morel et al., 2008 [47]).

Oxygen in polymer solution can degrade polymer viscosity. So, oxygen should be removed from polymer solution as it becomes unstable at high temperature (Du and Guan, 2004 [48]). Fracturing of low permeability zones can increase flow rate and recovery upon treatment with polymer flood. For 66 wells that were fractured and treated with polymer, the oil production rate per well increased by 46% (Wang et al., 2002 [49]).

Polymer flood faces more challenges in offshore fields than onshore (Raney et al, 2011 [50]). These challenges include transportation cost for chemicals, space for mixing at the platform, and reduced viscosity of the polymer when mixed with sea water. Polymer flood is being applied to Dalia field offshore Angola, at 1,300 m water depth (Morel et al, 2008 [51]). Following his work on the advances in polymer flooding for heavy oil recovery, Chang (2011) [52]) found that past laboratory research has shown that polymer flood can increase heavy oil recovery by 20%. Field applications in Bohai Bay offshore China, Bati Rahman in Turkey, Marmul in Oman have demonstrated the success of polymer flooding in heavy oil fields. However, the major challenge encountered in field applications was how to maintain polymer viscosity in surface injection facilities and under reservoir condition. The use of fresh water is preferable for mixing the polymer. Polymer flooding is a promising technology for heavy oil recovery, although high concentration is required to mobilize the oil which leads to increase in cost.

However, polymer flooding has not been applied in Nigeria. This paper seeks to study the application of polymer flooding to 2 Nigerian reservoirs (one offshore and one onshore) and to determine the viability of the method for the recovery of heavy oil in Nigeria.

The reservoirs which are designated as A (offshore) and B (onshore), were carefully chosen from the pool of Nigerian heavy oil reservoirs following a Non-Disclosure Agreement (NDA) with some oil companies in Nigeria who provided the data for this work. Viscosity, terrain, and availability of data were major factors in the choice of the reservoirs.

III. MATERIALS AND METHODS

3.1 Methodology

This chapter contains a summary of the heavy oil recovery technique and workflow used for research investigation, as well as the sensitivity analysis and the description of the reservoir models developed in this study. The highlight of the rock and fluid properties of the reservoirs, parameters of the Response Surface Methodology (RSM) design and criteria for the selection of optimal development technique was presented.

3.2 Workflow

Fig. 6 below shows the workflow of our methodology: The steps are explained below. Following the discovery and appraisal of any field, some data such as seismic, core, well logs and well test will be acquired and used to characterize the reservoirs in the field. Checks will be carried out on these data, to enhance the quality of the data collected. This is the first step in modelling any reservoir, as presented in the workflow as below. For this study, two datasets were received following a Non-Disclosure Agreement (NDA) with 2 companies that have heavy oil reservoirs in their assets. We conducted some quality checks on the data before using them to design our model for performance prediction. The next step was to apply the screening criteria in order to select the most suitable EOR technique based on reservoir characteristics and fluid property. The screening criteria was developed from the analysis of several successful EOR projects around the world, based on the knowledge of the physics of the EOR processes.

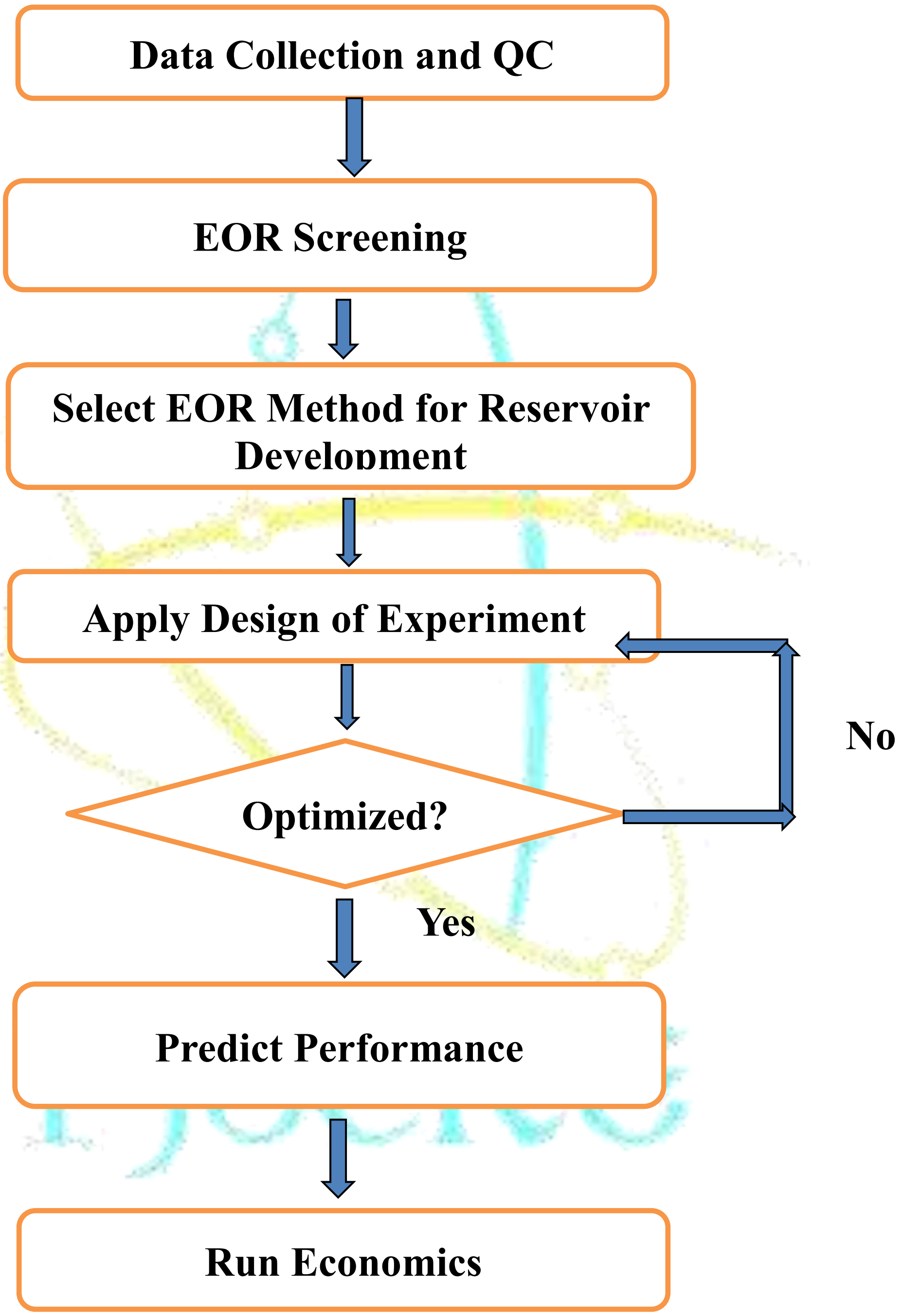

Figure 6. Workflow of the methodology

The screening criteria for sandstone reservoirs was adapted for the reservoirs in Nigeria to assess the characteristics of the reservoirs of interest (Reservoirs A & B) and their fluid properties in order to determine what EOR technique was suitable for them.

The screening criteria used was adapted from the works of Taber (1983) [53] and Donaldson (1985) [54]. Having reviewed the various screening criteria for selection of suitable EOR methods, we summarize them as shown in Table 4. It shows the reservoir characteristics and oil properties for which a given EOR is suitable. Therefore, given the reservoir characteristics and fluid property data, we can select a suitable EOR for the development of that reservoir. However, not all the requirements must be met for an EOR method to be selected. In our case, the data for Reservoir A is presented in Table 5 and based that, we applied the screening criteria to select a suitable EOR technique for the development of the reservoir. The EOR Selection process is shown in Table 6. From Table 6, the recommended EOR methods for the development of the HO from Reservoir A are Polymer Flooding, In Situ Combustion (ISC) and Steam Flooding. However, the focus of this work is the application of polymer flooding to HO reservoirs in Nigeria. Therefore, ISC and Steam Flooding were not pursued.

Following the selection of polymer flooding method for the reservoir, we applied the design of experiment to get optimum values to feed into the numerical reservoir simulator in order to predict the performance and then run the economics afterwards.

Table 4. Summary of EOR Screening Criteria

		Oil Properties			Reservoir Characteristics				
S/N	**EOR Method**	**Gravity (API)**	**Viscosity (cP)**	**Oil Sat (%PV)**	**Formation Type**	**Net Thickness (ft)**	**Ave K (mD)**	**Depth (ft)**	**Temp(F)**
Gas Injection Methods									
1.	Nitrogen & Flue gas	>35	<0.4	>40	Sandstone/ carbonate	Thin, unless dipping	NC	>6,000	NC
2.	Hydrocarbon	>23	<3	>30	Sandstone/ carbonate	Thin, unless dipping	NC	>4,000	NC
3.	CO_2	>22	<10	>20	Sandstone/ carbonate	Wide range	NC	>2,500	NC
Chemical Flooding									
4.	Micellar/ Polymer/ ASP/Alkaline	>20	<35	>35	Sandstone	NC	>10	>9,000	>200
5.	Polymer	>15	<200	>50	Sandstone	NC	>10	<9,000	>200
Thermal Methods									
6.	In-situ Combustion	>10	<5,000	>50	Sandstone	>10	>50	<11,500	NC
7.	Steam Flooding	>8	<200,000	>40	Sandstone	>20	>200	<4,500	NC

NC: Not Critical

Table 5. Study Reservoir Data (Reservoir-A)

Screening Criteria	Units	Input Data
Reservoir Temp	F	115
Oil Viscosity (In situ)	cP	560
Horizontal Permeability	mD	3,000
Driving Mechanism		Strong aquifer
Gas Cap		Yes, small
Water Salinity	ppm	12,000
Formation Type		Sandstone
Oil gravity	API	18.2
Reservoir Depth	ft	2,621
Net pay thickness	ft	100
Oil Saturation	%	0.9
Porosity	fraction	0.3

Table 6. Application of Screening Criteria

/N	EOR Method	Result	Reason
	Gas Injection Methods		
	Nitrogen & Flue Gas	Fail	Oil Gravity and Viscosity considerations
	Hydrocarbon	Fail	Oil Gravity and Viscosity considerations
	CO_2Flooding	Fail	Oil Gravity and Viscosity considerations
	Chemical Flooding		
	Micellar/ Polymer/ ASP/ Alkaline Flooding	Fail	Reservoir Depth consideration
	Polymer Flooding	Pass	Only viscosity was out of range. However, polymer flooding was successfully applied in a field with over 1,000cP in Caen field of Western Canada (Renouf, 2014)
	Thermal Methods		
	In-Situ Combustion	Pass	
	Steam Flooding	Pass	

3.3 Design of Experiment (DoE)

Design of Experiment (DoE) is a statistical method to systematically investigate a systems' Input-Output (I/O) relationship in order to identify design variables, optimize product/process design and achieve robust performance (Durakovic, 2017 [55]). It has been a popular tool in medicine, engineering, physics, computer science, etc. It is a mathematical technique that is used for conducting experiments, analyzing and interpreting the data obtained therefrom. It is used in the systematic study of a process, system, simulation models, product quality, reliability, and improvement in which input variables (Xi) are manipulated to determine their effect on measured response variable (Y). It also provides a guide as to which factors should be considered important, as there could be many factors (Montgomery, 2013 [56]).

In this work, Response Surface Methodology (RSM) was employed to understand the interaction between parameters of interest in polymer flooding, and how these interactions affect the cumulative oil produced. In addition, it was also used to estimate the optimal values for the parameters of interest and to maximize the cumulative oil production. The dependent variable was cumulative oil production, while the independent variables were the factors that affect oil production from polymer flooding.

For the polymer flooding, we found that the cumulative production was a function of eight (8) major variable as stated in the Equation (1) below:

$$FOPT = f\left(\emptyset, K_e, P_{ir}, P_{ic}, W_{ir}, W_{ic}, \frac{K_v}{K_h}, P_c\right) \quad (1)$$

Where:

FOPT = cumulative oil production in bbls,

$\mathrm{P_{ir}}$ = Polymer injection rate in $\frac{\mathrm{bbl}}{\mathrm{d}}$,

$\mathrm{P_{ic}}$ = Polymer injection cycle in days,

$\mathrm{W_{ir}}$ = water injection rate in $\frac{\mathrm{bbl}}{\mathrm{d}}$,

$\mathrm{W_{ic}}$ = water injection cycle in days,

$\mathrm{P_c}$ = polymer concentration in $\frac{\mathrm{bbl}}{\mathrm{stb}}$,

$\mathrm{K_e}$ = effective permeabilityin mD,

$\emptyset$ = porosity, and

$^{K_v}/_{K_h}$ = permeability anisotropy

D-optimal design was used to select and generate the number of experimental runs as it leads to reduced number of runs when compared to factorial design. The D-efficiency values are a function of the number of points in the design, the number of independent variables in the model, and the maximum standard error for prediction over the design points. The best design is the one with the highest D-efficiency. This is gotten from a random combination of the variables.

The Design-Expert software which is the core tool for DoE has an RSM module that applies D-optimal design to minimize the number of runs. It was used to get the coefficient of terms from the data analysis module in Minitab, which was then put together to get the regression equation. The software also conducts Analysis of Variance (ANOVA) which is used to determine the model statistics that includes standard deviation (σ), Coefficient of determination (R^2), adjusted R^2, p-values, etc, which are used to quantify how good the model equation is in estimating the outcome.

The regression equation will become a diagnostic tool for a first pass determination of cumulative oil production when polymer flooding EOR method is applied for HO recovery.

3.4 Reservoir B

We also considered another reservoir (Reservoir B) which is onshore, in a Niger Delta field. Based on the EOR screening criteria which was similar to Reservoir A, polymer flooding was selected for Reservoir B also. The model for this reservoir of interest was built with the properties as specified in the G & G report, PVT reports and data from field development plan (FDP) given by the company following a Non-disclosure Agreement.

3.4.1 Reservoir B Performance Prediction

Based on the diagnostic tool developed from DoE in this research work, the performance of the Reservoir B was predicted using the tool. Reservoir simulation was then used to validate the predictions from the diagnostic model equations for reservoir performance. Afterwards, the economics of the process was analyzed. The two models were plotted on the same scale to check how the diagnostic model compares with the reservoir simulation, and hence determine its predictive integrity.

3.5 Economics of Polymer EOR Method for HO Recovery

We used the discounted cashflow model for deterministic economic analysis. The deterministic model was developed on Microsoft excel platform. The capital and operating costs incorporated into the deterministic model were estimated using the Questor software by IHS Markit.

The input parameters from the deterministic economic models built for the two (2) different reservoirs are shown in Tables 7 and 8, while the decision rules for the economic indicators was shown in Table 9 The input data for reservoir A varies from reservoir B. Reservoir A is a shallow offshore field, with reserve size of 100MMSTB. Reservoir B is an onshore field of 50MMSTB. Both fields may be classified as marginal, however reservoir A has more recoverable oil on application of polymer recovery method. HO price is usually discounted by as much as 30% to 50% conventional oil price.

Table 7. Input Parameters for deterministic model for Reservoir A (Shallow offshore field) - Polymer Flooding. (Source: Author's compilation)

Field Data	Details	Units
Reserves Size	100	MMSTB
Heavy Oil Price	20	$/bbl
Price Escalation rate	2%	
Discount rate	15%	
Total CAPEX	793	$M
Variable OPEX	3%	of gross revenue per year
Field OPEX	5%	of CAPEX

Field life	20	years
Initial production rate	8,000	bbls/day
Peak production rate	8,000	bbls/day
Signature Bonus	300,000	$
Royalty rate	18%	of Gross revenue per year for Shallow field
Tax	67.5%	First five years
	85%	Subsequent years
NDDC levy	3%	of Taxable income
Education Tax	2%	of Taxable income
Cost Recovery Limit	100%	of Net revenue after royalty
Abandonment cost	1%	(The host government bears the cost of abandonment)

Table 8. Input Data for Reservoir B (Onshore field) Polymer Flooding (source: Author's compilation)

Field Data	**Details**	**Units**
Reserves Size	50	MMSTB
Heavy Oil Price	20	$/bbl
Price Escalation rate	2%	
Discount rate	15%	
Total CAPEX	460	$M
Variable OPEX	2%	of gross revenue per year
Field OPEX	3%	of CAPEX
Field life	10	years
Initial production rate	2,000	bbls/day
Peak production rate	2,000	bbls/day
Signature Bonus	300,000	$
Royalty rate	20%	of Gross revenue per year for onshore field
Tax	67.5%	First five years
	85%	Subsequent years
NDDC levy	3%	of Taxable income
Education Tax	2%	of Taxable income
Cost Recovery Limit	100%	of Net revenue after royalty
Abandonment cost	1%	(the host government bears the cost of abandonment)

Table 9. Decision rules for Economic Indicators (Nwosi-Anele et al., 2018)

PROFITABILITY MEASURES	**ACCEPT IF @ i_d***	**REJECT IF @ i_d***
NPV	≥ 0	≤ 0
IRR	$>i_d$*	$<i_d$*
UTC	< product price	>product price

IV. Results and Discussion

4.1 Polymer Flooding

Considering the fact that the polymer (HPAM) is expensive, a development strategy which involves the injection of polymer solution followed by chase water was considered so as to reduce the overall cost of polymer (the operating cost of the project). Thus, the optimum polymer concentration, polymer cycle, polymer slug size as well as chase water size and cycle need to be determined. More so, to understand the interaction of these parameters and how they affect the recovery efficiency, an experimental run was designed to develop a model relating the input parameters to the response (cumulative oil produced) as well as optimize the response.

4.1.1 Design of Experiment for Polymer Flooding

Preliminary studies were performed to determine the required range of parameters as shown in Table 10. This is in close agreement with the findings of Chang (2011) [57] in his paper on the field application of polymer flooding. The whole design consisted of 55 experimental runs and performed with all design points in randomized order. The RSM method, based on a two-level D-Optimal design, was employed to obtain the optimal combination of injection condition. Basically, this is achieved by sorting a random combination of the variables until one that gives the highest cumulative production is achieved.

Table 10. Range of Parameters for Polymer Flood Experimental Runs

Parameter	Unit	Low	High
Porosity	%	25	33
Permeability	mD	1500	3000
Polymer Injection Rate	bbl./D	100	1500
Polymer Injection Cycle	Days	30	90
Water Injection rate	bbl./D	100	1500
Water Injection cycle	Days	90	180
Kv/Kh	%	10	60
Polymer Concentration	bbl./STB	2	10

Through multiple regression analysis on the experimental data, the predicted response FOPT for the cumulative production could be expressed by the following second-order polynomial equation in terms of the uncoded values:

$$
\begin{aligned}
\boldsymbol{FOPT} = {} & 256\mathrm{P_{ir}}^2 - 821\mathrm{P_{ic}}^2 + 0.6\mathrm{W_{ir}}^2 - 1.4\mathrm{K_e}^2 + 1,340\mathrm{W_{ic}}^2 - 269,739\emptyset^2 + 9,977\mathrm{P_c}^2 \\
& - 3889\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}}{}^2 \\
& - \mathrm{P_{ir}}\left[355 + 13\emptyset - 2.083\mathrm{K_e} + 50.5\mathrm{P_{ic}} - 2.577\mathrm{W_{ir}} + 59.7\mathrm{W_{ic}} + 37.6\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}} \right. \\
& \left. - 108\mathrm{P_c}\right] \\
& + \mathrm{P_{ic}}\left[294,460 - 3156\emptyset - 53.9\mathrm{K_e} - 71\mathrm{W_{ir}} + 1,165\mathrm{W_{ic}} + 2,367\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}} - 9,860\mathrm{P_c}\right] \\
& - \mathrm{W_{ir}}\left[10,092 - 325\emptyset - 2.351\mathrm{K_e} + 27.8\mathrm{W_{ic}} + 29.7\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}} - 153\mathrm{P_c}\right] \\
& + \mathrm{W_{ic}}\left[111,711 - 3,746\emptyset - 39.9\mathrm{K_e} + 100\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}} - 2,138\mathrm{P_c}\right] \\
& + \mathrm{P_c}\left[601,880 - 39,279\emptyset + 513\mathrm{K_e} - 13,584\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}}\right] \\
& + \mathrm{K_e}\left[8,703 + 7\emptyset - 44.1\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}}\right] + \emptyset\left[16,068,528 + 2,793\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}}\right] \\
& + 305,745\, {}^{\mathrm{K_v}}/_{\mathrm{K_h}} \qquad (2)
\end{aligned}
$$

Where:

FOPT = cumulative production,
$\mathrm{P_{ir}}$ = polymer injection rate,
$\mathrm{P_{ic}}$ = polymer injection cycle,
$\mathrm{W_{ir}}$ = water injection rate,
$\mathrm{W_{ic}}$ = water injection cycle,
$\mathrm{P_c}$ = polymer concentration,
$\mathrm{K_e}$ = effective permeability,
$\emptyset$ = porosity,
and ${}^{\mathrm{K_v}}/_{\mathrm{K_h}}$ = permeability anisotropy

Hypothesis testing of the model was performed in the form of analysis of variance (ANOVA). Table 11 shows the summary of the model statistics. The quadratic regression model showed the value of coefficient of determination (R^2) of 0.9671 with no significant lack of fit at $p > 0.05$, which means that the calculated model was able to explain 96.71% of the results. The results indicated that the model used to fit the response variable was significant ($p < 0.0001$) and adequate to represent the relationship between the response and the independent variables. The significance of the model was also judged by F-test, which suggested that model had a high F-value ($F = 6.67$). The adjusted coefficient of determination, R^2adj, is the correlation measure for testing the goodness-of-fit of the regression equation (Kim et. al., 2012 [58]). The R^2adj value of this model is 0.8222, which indicate that only 17.78% of the total variations were not explained by model.

Equation (2) would serve as a diagnostic tool in the industry for reservoirs with properties within the range selected for the chosen case, in that a quick and efficient estimate of the cumulative oil production can be determined given the parameters involved, when polymer flooding is applied in a heavy oil reservoir. For reservoirs with parameters outside the range however, the accuracy would be reduced, but it would serve as a guide, nonetheless. This model gains its robustness from the fact that it captured reservoir parameters for the chosen case as well as the production parameters, thus, giving a good representation of the entire production system assuming there are no flow assurance issues.

The 3D response surface plot and the contour plot derived from the mathematical models were applied to determine the optimal conditions. In summary, the optimal injection condition per cycle of production was a polymer injection rate of 100 bbl./D, polymer cycle of 90 days, chase water size of 100 bbl./D, chase water cycle of 180 days and polymer concentration of 2.0 bbl./STB. This condition was replicated for several cycles until the incremental recovery was small, thus, signifying the loss of efficiency of the flooding process.

The model is robust because it captured reservoir parameters as well as the production parameters, thus, giving a good representation of the entire production system. Moreso, a normal probability plot shown in Fig. 7 affirms a good representation of the data by the model. As seen from the plot, the data points have minimal deviation from model prediction which shows that the diagnostic tool is robust and that the level of accuracy is high.

Table 11. Model Statistics Summary

R-sq.	R-sq. (Adj)	F-Value	P-Value
96.71%	82.22%	6.67	0.001

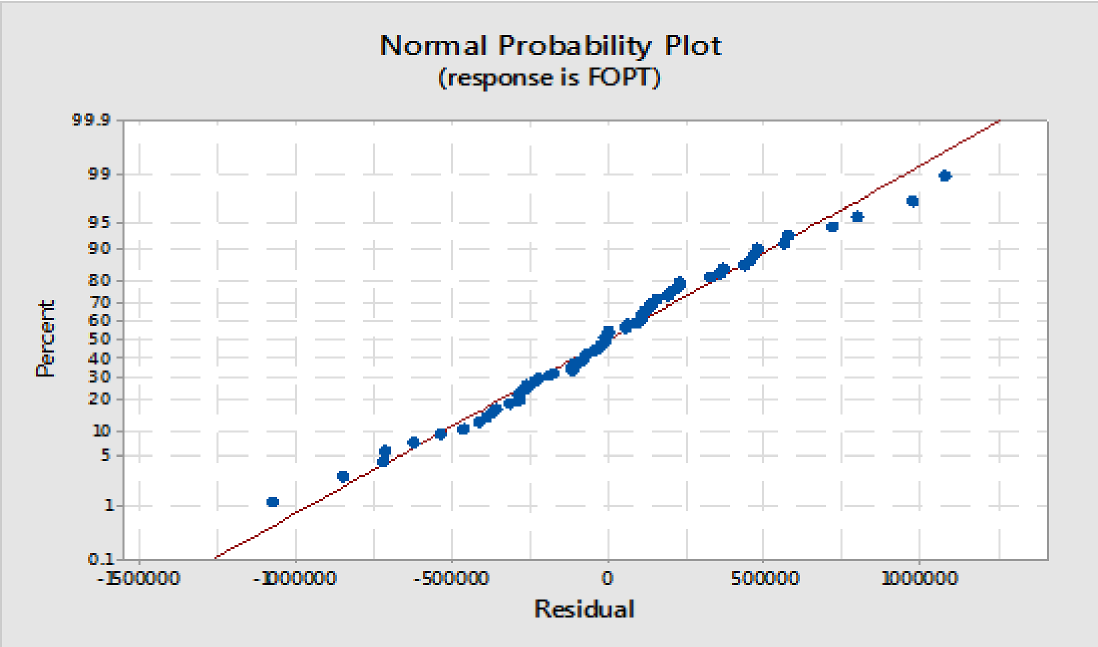

Figure 7 Normal Probability Plot

Having determined the optimal conditions using RSM, we went on to run the reservoir simulation model. The results which show polymer flooding, natural depletion and water flooding and steam flooding is shown in Fig. 8. in terms of rate and recovery efficiency. Table 12 also shows the recovery efficiencies of the various techniques based on the performance prediction.

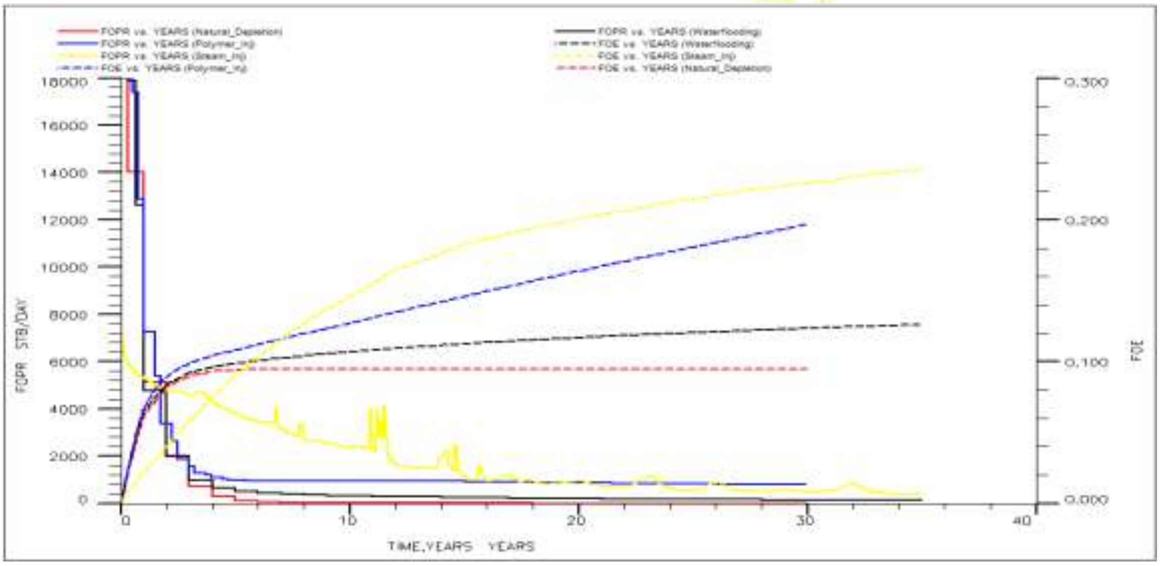

Figure 8 Comparison of natural depletion, waterflooding, polymer flooding and steam flooding in terms of recovery efficiency

Table 12. Summary of performance prediction of various recovery techniques

Reservoir	Years of EOR	Recovery Efficiency (%)			
		Natural Depletion	Water Flooding	Polymer Flooding	Steam Flooding
X	35	9	13	21	24

4.2 Reservoir B (Onshore)

Reservoir B is in an onshore field with the average properties presented in Table 13. As in the previous case, the reservoir and fluid properties fall into the same band when we apply the screening criteria for EOR selection, and we selected polymer flooding as well. We shall apply the diagnostic model developed earlier for this reservoir, then determine the optimum values of the parameters to apply the reservoir simulation model to predict the performance.

Table 13. Study reservoir properties (Reservoir-B)

Screening Criteria	Units	Input Data
Reservoir Temp	F	144
Oil Viscosity (In situ)	cP	52
Horizontal Permeability	mD	2,665
Driving Mechanism		moderate aquifer
Gas Cap		No
Water Salinity	ppm	N/A
Formation Type		Sandstone
Oil gravity	API	19
Reservoir Depth	ft	2,970
Net pay thickness	ft	49
Oil Saturation	%	0.85
Porosity	fraction	0.3

4.2.1 Prediction of Reservoir B Performance

The diagnostic model (Eqn. 2) was applied to the range of values of the data for Reservoir B. This implies that random values of porosity, permeability, polymer injection rate, polymer injection cycle, water injection rate, water injection cycle, K_v/K_h, polymer concentration that are consistent with the possible values of these variables were substituted into the diagnostic model to determine the cumulative production.

Now based on the combination of values of the variables that give the highest outcome (for cumulative production), we determined the optimum values and used that data for performance prediction in our reservoir simulation model. We then ran sensitivity on our simulation model using the values that were imputed in the diagnostic model. We compared the response of the diagnostic model with that from the reservoir simulation.

Fig. 9 shows the field oil recovery efficiency of the natural depletion, polymer injection and steam injection models of reservoir B and as shown in the figure, the natural depletion could only attain 3.5 % recovery factor. However, with the implementation of polymer injection, a recovery of 9.07 % was obtained. The trend for the polymer injection stops at 9.8 years due to pressure decline due to poor pressure maintenance. (the steam injection model was not shown in this work).

Polymer injection leads to an increase in rate as a result of improvement in the mobility ratio of oil but does not provide enough pressure support to the system, thus, pressure maintenance must be put in place to sustain the production beyond 8 years. We also noted that Reservoir B has a moderate aquifer compared to Reservoir A that has a strong aquifer.

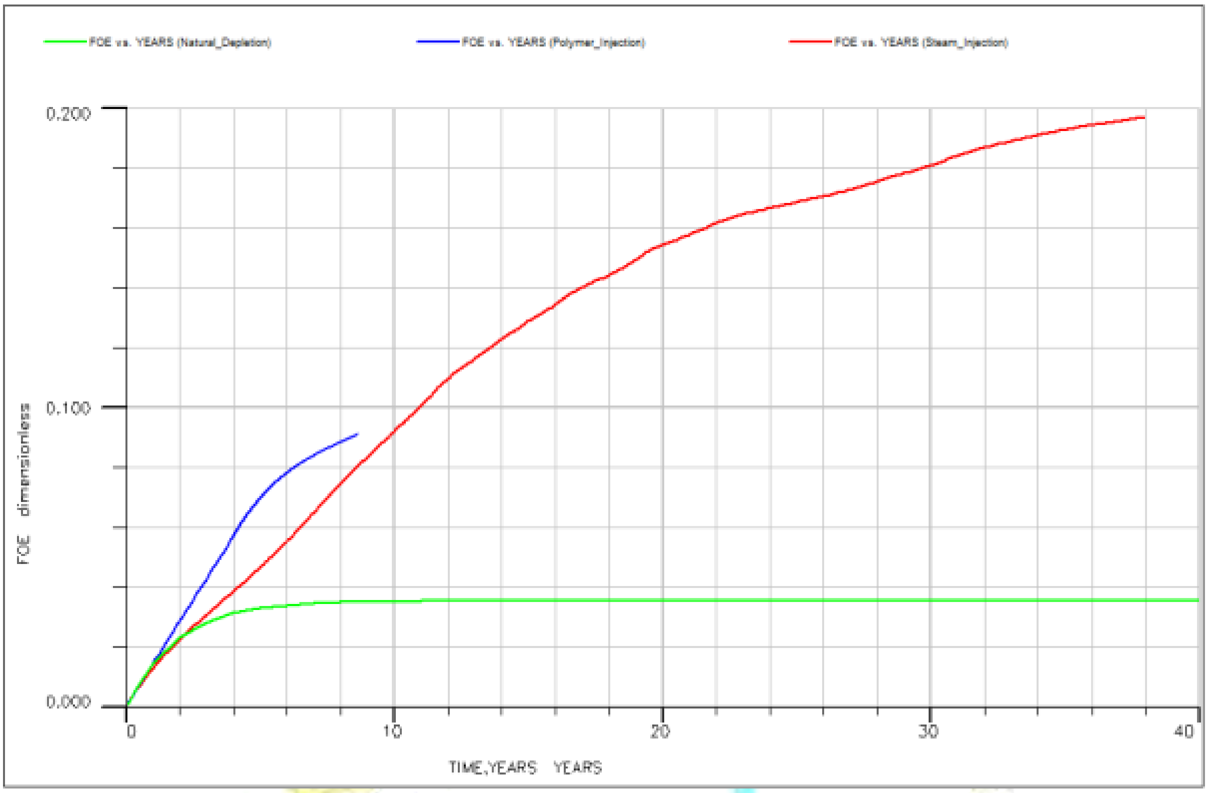

Figure 9. Field Recovery Efficiency for B Reservoir

4.2.2 Summary of Results Reservoir B

The table below shows the recovery efficiencies of the various techniques based on the performance prediction from reservoir simulation.

Table 14 Summary of performance prediction of various recovery techniques

Reservoir	Years of EOR	Recovery Efficiency (%)			
		Natural Depletion	Water Flooding	Polymer Flooding	Steam Flooding
X	35	3.5	6	9	20

4.3 Diagnostic Model Validation

The diagnostic model was validated by comparing its result with that of reservoir simulation to establish its robustness as well as its level of accuracy in prediction. The two models were plotted on the same scale as shown in Fig. 10. From the trends of the several experimental runs, the difference between the results is low (less than 5%) thus, signifying a near accurate prediction by the diagnostic tool. That was a validation of the diagnostic model.

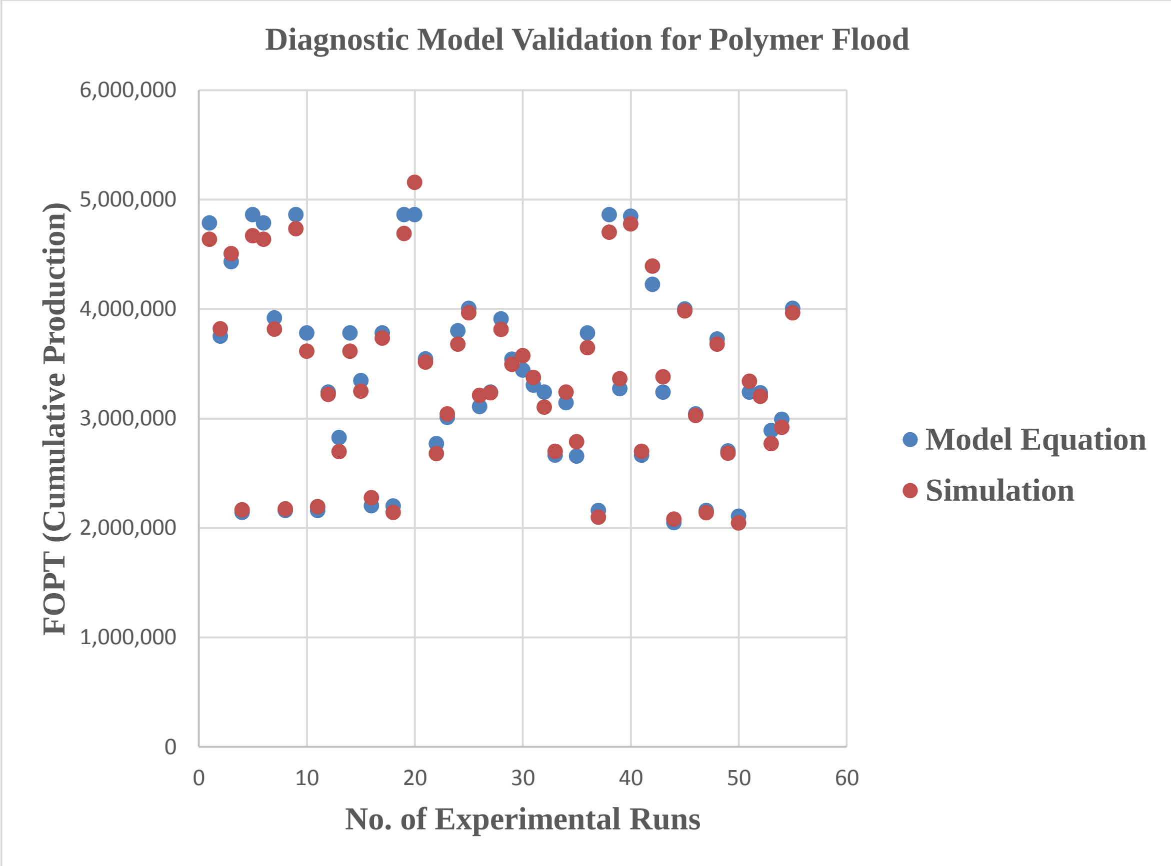

Figure 10. Diagnostic Model Validation for Polymer Flood

4.4 Results & Analysis of the Economic Model

The results show the findings of the economic evaluation of HO recovery for the offshore (A) and onshore (B) reservoirs considered as discussed earlier based on the current fiscal regime, with the production profile from the optimized flooding pattern used for the analysis. The result of our deterministic model (Discounted Cash Flow) shows that at varying prices between $15/bbl., $20/bbl., and $25/bbl. The reservoirs B and A producing heavy oil using polymer flooding remained profitable. The details of the results are discussed in the sections below:

4.4.1 Deterministic Results for Reservoir B and Reservoir A for the different HO Price

The deterministic model was built with heavy oil price of $20/bbl as base case heavy oil price, $15/bbl heavy oil price was used as worst-case scenario and $25/bbl was used as best-case scenario heavy oil price. This is because heavy oil price is usually discounted by 30% to 50% conventional oil price. Tables 15, 16 and 17 shows that the heavy oil field projects for reservoirs B and A, produced using polymer injection recovery method was found to be profitable.

Comparing the results of our economic models in Tables 15, 16 and 17 with Table 9 showing the criteria for measuring profitability using economic indicators, it can be seen that the discount rate of 15% is lower than the internal rate of return for both reservoirs in all heavy oil price scenarios, the net present value is positive for both reservoirs for all heavy oil price scenarios. The unit technical cost is lower than the worst-case scenario heavy oil price of $15/bbl. This implies than the heavy oil field venture is profitable.

Reservoir B having about 50MMstb oil originally in place (OOIP) was found to be profitable despite its low reserve. The unit capital expenditure and unit operating expenditures were found to be profitable because they present very low figures compared with the heavy oil prices applied in all models. The before income tax (BFIT) and after income tax (AFIT) contractor’s take were positive although the difference between the before income tax and after income tax contractor take is huge showing the large difference of cash dispensed as tax to host government. The overall field economics is profitable for both contractor and host government. Sensitivity analysis was done for varying heavy oil price of $15/bbl, $20/bbl and $25/bbl shows an all-profitable heavy oil field project. However, the profitability varies based on the recoverable reserve volume for reservoirs B and A produced by polymer flooding.

Table 15. Profitability analysis at $20/BBL heavy oil price (Base Case)

	RESERVOIR B	RESERVOIR A
Economic Indicators	**Polymer Flooding**	**Polymer Flooding**
Discount Rate (%)	15	15
Internal Rate of Return (%)	38%	35%
Net Present Value ($M)	8,577.70	27,42 9.24
Unit Technical Cost ($/Bbl)	1.21	1.18
Unit Capex ($/Bbl)	0.097	0.008
Unit Opex ($/Bbl)	1.11	1.17
BFIT ($M)	6,519.53	300,173.48
AFIT ($M)	8,577.70	27,429.24
Payback Period (Years)	> 2 years	> 2years

Table 16. Profitability analysis at $15/BBL heavy oil price (worst case scenario)

	RESERVOIR B	RESERVOIR A
Economic Indicators	**Polymer Flooding**	**Polymer Flooding**
Discount Rate (%)	15%	15%
Internal Rate of Return (%)	33%	31%
Net Present Value ($M)	6,366.18	20,53 4.56
Unit Technical Cost ($/bbl)	0.93	0.89
Unit Capex ($/Bbl)	0.097	0.008
Unit Opex ($/Bbl)	0.84	0.88
BFIT ($M)	70,515.4 1	225,1 30.11
AFIT ($M)	6,366.18	20,534.56
Payback Period (Years)	> 2 years	> 2years

Table 17. Profitability analysis at $25/BBL heavy oil price (best case scenario)

	RESERVOIR B	RESERVOIR A
Economic Indicators	**Polymer Flooding**	**Polymer Flooding**
Discount Rate (%)	15%	15%
Internal Rate of Return (%)	33%	31%
Net Present Value ($M)	10,789.2 2	20,53 4.56
Unit Technical Cost ($/Bbl)	1.49	0.89
Unit Capex ($/Bbl)	0.097	0.008
Unit Opex ($/Bbl)	1.39	0.88
BFIT ($M)	117,527. 58	225,1 30.11
AFIT ($M)	10,789.2 2	20,53 4.56
Payback Period (Years)	> 2 years	> 2years

V. Conclusions and Recommendations

5.1 Conclusion

1. Polymer injection can be applied in Nigerian HO reservoirs that meet the selection criteria.
2. The current fiscal regime is not good enough for the development of heavy oil in Nigeria, based on the reservoirs considered and the method applied for their development.
3. Design of Experiments (DoE) can be used to determine the optimum values of the reservoir and operating parameters for Heavy Oil recovery using Polymer EOR application.
4. A diagnostic model that has the capacity to predict the field cumulative oil production for heavy oil recovery in the Niger Delta when polymer flooding techniques is applied was developed.
5. The deterministic model shows that polymer flooding was viable for the reservoirs considered.

5.2 Recommendations

Based on the finding of our research, especially the economic model (deterministic and stochastic), the following recommendations are made for further studies to improve the methodology and results discussed in this work.

1. We recommend that the fiscal policy be modified to provide an incentive to investors and operators for the development of Nigerian heavy oil, in particular, the tax rate should be adjusted downwards from 85% of taxable income to 50% for a heavy oil field to allow the investor to make more profit considering the low price of heavy oil, high cost of production that requires enhanced oil recovery methods and lower recovery volumes compared to conventional oil.
2. The study is conceptual at this stage because the reservoirs studied have not been produced. Therefore, a pilot and full field study need to be conducted so that production data can be acquired for history matching and prediction.

5.3 Contribution to Knowledge

We developed a diagnostic model for the application of polymer flooding in heavy oil reservoirs in the Niger Delta.

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LIST OF ABBREVIATIONS

AER	Alberta Energy Regulator
ANP	National Agency of Petroleum (Brazil)
ANOVA	Analysis of Variance
API	American Petroleum Institute
ASP	Alkaline Surfactant Polymer
CAPEX	Capital Expenditure
CNPC	China National Petroleum Corporation
DPR	Department of Petroleum Resources
DOE	Design of Experiment
EOR	Enhanced Oil Recovery
ESP	Electric Submersible Pump
HO	Heavy Oil
HPAM	Hydrolysed Polyacrylamide
IEA	International Energy Agency
IRR	Internal Rate of Return
JPT	Journal of Petroleum Technology
MFAT	Multiple Factors at a Time
NCDMB	Nigerian Content Development Management Board
NCF	Net Cash Flow
NDA	Non-Disclosure Agreement
NDDC	Niger Delta Development Commission
NPDC	Nigerian Petroleum Development Company
NPV	Net Present Value
OFAT	One Factor at a Time
ONGC	Oil and Natural Gas Corporation (India)
OOIP	Oil Originally in Place

OPEX	Operating Expenditure
PDO	Petroleum Development Oman
RSM	Response Surface Methodology
SNEPCO	Shell Nigeria Exploration & Production Company
SPDC	Shell Petroleum Development Company
UTC	Unit Technical Cost
USGS	United States Geological Survey
UNITAR	United Nations Institute for Training and Research
WPC	World Petroleum Congress
XHO	Extra Heavy Oil