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Recovery of Nigerian Heavy Oil: Application of Steam Flooding

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Authors' contributions

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

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ABSTRACT

Aims: 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 Steam Flooding 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.
Study Design: Data was collected for two heavy oil reservoirs from two oil companies in Nigeria following a Non-disclosure Agreement (NDA).
Place and Duration of Study: Emerald Energy Institute, University of Port Harcourt Nigeria, 2016 - 2021.
Methodology: The screening criteria of commercially effective EOR methods were applied to select steam 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 the performance of the reservoirs. The economics of the steam flood technique endorsed for the reservoirs considered were also evaluated using Discounted Cash Flow Analysis (DCFA).
Results: These assessments confirmed that steam flooding technique was technically and economically viable for the heavy oil reservoirs considered. The steam flood was observed to have

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a good recovery efficiency of 24%, as against the waterflooding technique which had 13% OOIP and natural depletion of 9% for the offshore reservoir. For the onshore reservoir, the recovery efficiency was 20% for steam flood, and 4% for natural depletion. The economic analysis showed that even at a worst-case heavy oil price of US$15, the project was viable.

Conclusion: Steam flooding is viable, can be applied to develop heavy oil reservoirs in Nigeria that meet the screening criteria, and thus increase national oil reserve and production.

Recommendation: The fiscal policy should be adjusted, especially the petroleum profit tax from 85% to 50% as an incentive to operators and investors to embark on steam flooding and other EOR methods.

Keywords: Heavy oil; enhanced oil recovery; design of experiment; net present value.

ABBREVIATIONS

AER	*: Alberta Energy Regulator*
ANP	*:National Agency of Petroleum (Brazil)*
ANOVA	*: Analysis of Variance*
API	*: American Petroleum Institute*
CAPEX	*: Capital Expenditure*
CHOPS	*: Cold Heavy Oil Production with Sand*
CNPC	*: China National Petroleum Corporation*
CSI	*: Cyclic Steam Injection*
CSS	*: Cyclic Steam Stimulation*
DPR	*: Department of Petroleum Resources*
DOE	*: Design of Experiment*
EOR	*: Enhanced Oil Recovery*
ESP	*: Electric Submersible Pump*
HO	*: Heavy Oil*
IEA	*: International Energy Agency*
IRR	*: Internal Rate of Return*
ISC	*: In Situ Combustion*
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*
SAGD	*: Steam Assisted Gravity Drainage*
SF	*: Steam Flooding*
SNEPCO	*: Shell Nigeria Exploration & Production Company*
SPDC	*: Shell Petroleum Development Company*
THAI	*: Toe-to-Heel Air Injection*
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*

1. INTRODUCTION

1.1 Background

There are heavy oil (HO) and extra heavy oil (XHO) deposits in over 35 countries of the world, with the largest in Canada and Venezuela [1,2].

The International Energy Agency [3] 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 [4].

1.2 Heavy oil Resources in Nigeria

There are over 50 HO reservoirs in Nigeria, with total reserves of over 2 billion barrels (DPR). Some of the HO reservoirs and the field containing them include those shown in Table 1.

Most of the fields in Table 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 HO reservoir in Bonga Southwest with API of 19.2) in their proposed field development plan for Bonga SW Aparo. The volume in place for that reservoir was about 608 MMSTB. It could be that the reservoir did not meet the economic criteria for development by the Company based on cold 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 the fall in oil price in recent times and the property of the oil in question and what cost-effective technology to use.

In Nigeria, so far, although Cold Conventional Production with horizontal wells is used for heavy oil development, there is a dearth of publication on the suitable application of HO recovery methods in the Niger Delta. This research intends to contribute to addressing that gap and thus explore options for HO development in Nigeria by using a case study of some heavy oil reservoirs.

1.3 Characteristics and Properties of Heavy Oil

Heavy Oil is defined as crude oil that has API gravity of < 20^o (US API), API gravity of $10\text{-}19^0$ (Brazilian ANP), or as the World Petroleum Congress (WPC) defines it, crude oil with API gravity of $10\text{-}22.3^0$. Some authors specify viscosity>10cP or density above 0.920 g/cm^3 [5], [6], 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 [7,8]. The United Nations Institute for Training & Research (UNITAR) defines HO as gas free oil at viscosity of 100-10,000cP and density of 0.934 - 1.000g/cm^3 at standard conditions [9]. Therefore, we define heavy oil based on viscosity (10-100cP) and API gravity (10-22.3°) at initial reservoir conditions.

The low mobility of HO at in-situ condition prevents the reliance on natural drive mechanism for its exploitation. In addition, the application 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 addition of enthalpy into the reservoir by injection of hot fluid or addition/creation of heat in the reservoir. Viscosity is internal friction, the resistance of liquid to change in form, which can be reduced by heat as it decreases with increase in temperature (as suggested by Arrhenius theory). As reservoir temperature increases, viscosity of HO decreases, and the flow rate increases due to increase in mobility.

To develop HO reservoirs, we need to choose technology that is effective with improved recovery efficiency based on the characteristics of the reservoir and the fluid properties.

1.4 Brief Literature Review

1.4.1 Some theoretical framework

HO reservoirs require different enhanced oil recovery (EOR) techniques depending on fluid properties and characteristics of the reservoir containing the oil. The rheological properties of HO and the characteristics of its reservoirs make its production a challenge in the oil industry. Fig. 1 below shows typical recovery factors. The figure shows that for light oil reservoirs, primary and secondary methods can recover 25% and 30% respectively 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.

While microscopic transport properties like relative permeability and capillary pressure are responsible for conventional displacement, it was discovered that heavy oil reservoirs do not respond significantly to conventional recovery techniques of primary and secondary recovery methods due to the viscous nature of its oil. Therefore, HO recovery requires the use of Enhanced Oil Recovery (EOR) methods which reduces viscous and capillary effects to achieve significant impact on recovery efficiency. The application of EOR method introduces a new substance into the reservoir to reduce the residual oil saturation. EOR can be applied after primary and secondary recovery or straightaway for HO reservoirs. The performance of an EOR method is measured by the amount of additional oil that can be economically recovered compared to that obtained by conventional methods.

The total world oil production from EOR in 1998 was about 2.2 MM BOPD, out of which about 43% (1 MM BOPD) was 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 [10].

A combination of triple scenarios, which are: increasing energy demand, declining performance of conventional oil fields and attractive oil prices are the drivers for the interest in HO resources and the methods for developing them [11,12,13].

1.4.2 Some technical options for heavy oil recovery

HO reservoirs that meet certain descriptions 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, or interfacial tension. So far, the most proven approach to producing HO reservoirs is through thermal methods, for which Steam Flooding is the most successful, and our focus in this work. Some of the other methods are shown in Fig. 2.

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
24.	Sapele	B4100X	20.1	38.8	120	Onshore
25.	Ekulama	E5000A	20.3	308.0	140	Onshore
26.	Mosogar	U2000X	20.3	19.5	117	Onshore
27.	Sapele	B2700W	20.3	32.3	117	Onshore
28.	Sapele	B3600	20.6	27.4	119	Onshore
29.	Ebok	LD-IB	15.1	540.0	110	Offshore
30.	Bonga	R670	19.2			Offshore

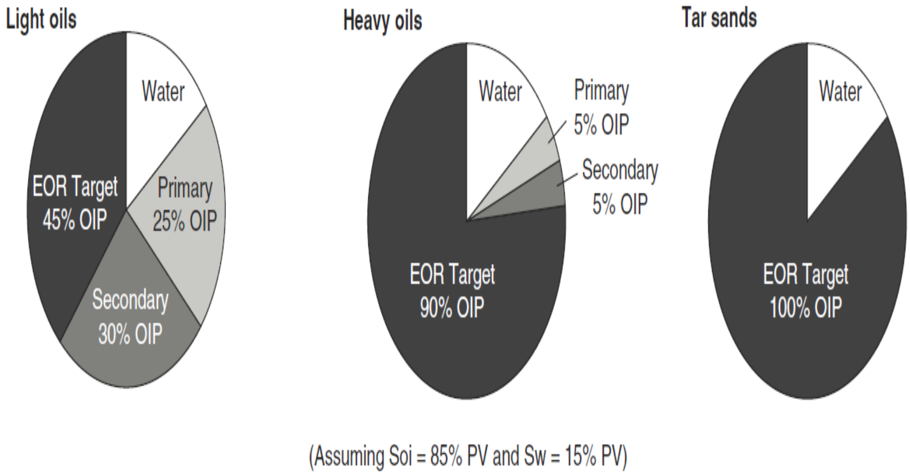

Fig. 1. EOR targets for different hydrocarbons (Thomas, 2008)

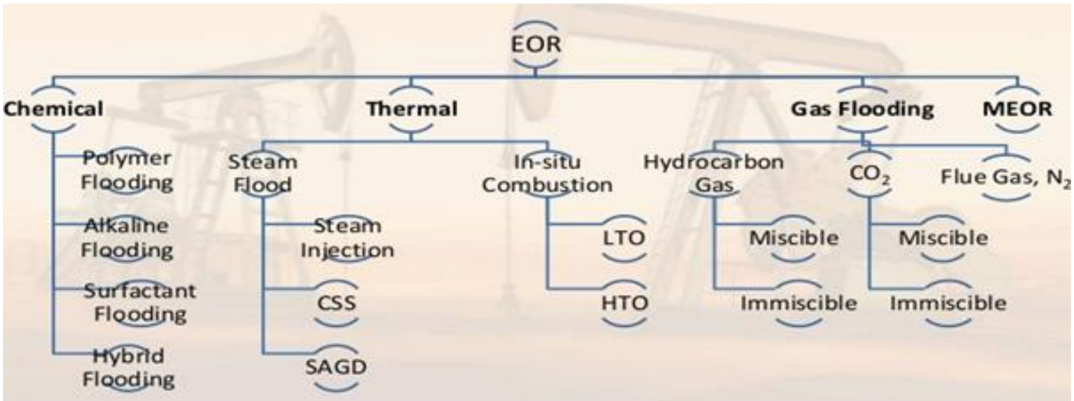

Fig. 2. Classification of EOR (oges.info)

1.4.3 Thermal methods of heavy oil recovery

The main objective of thermal methods is to add enthalpy to the reservoir in order to reduce the flow resistance by reducing the oil viscosity and consequently increasing the oil mobility for production. These methods include Steam Flooding, Cyclic Steam Injection (huff & puff), In-Situ Combustion (ISC), Steam Assisted Gravity Drainage (SAGD) and other variants. This paper is concerned with the application of steam flooding in the recovery of Nigerian heavy oil.

1.4.4 Continuous steam injection / steam flooding

In this method, steam is continuously injected into one or more vertical wells and the oil is pushed to the producing wells. The steam creates a chamber that moves across the reservoir, promoting oil sweep. Given that this method requires injectors and producers, a larger area of the reservoir is required, and therefore oil recoveries are higher than what Cyclic Steam Stimulation (CSS) provides. Recovery Factor could be up to 60% for steam flooding.

However, thermal efficiency could be lower due to higher heat loss, the pay-out period is longer, and the cost (CAPEX and OPEX) is higher due to higher fuel consumption for steam generation for each barrel of oil recovered. Heating the oil results in thermal expansion, viscosity reduction, activation of solution gas drive, thermal cracking and potential wettability alteration [14]. The steam lowers the viscosity of the oil, increases its mobility and displaces it towards the producing well. The mechanism is illustrated in Fig. 3. There is a steam chamber in the vicinity of the injection well at steam temperature, then there is the hot water zone ahead (from condensed steam) in which a mixture of heated oil and hot water is pushed towards the production well. Fig.

4 is an illustration of steam injection in an inverted 5-spot grid.

Steam Flooding is the most commercially successful method as 60% of HO produced by EOR is attributed to it [15]. Out of the 208 HO EOR projects in 1998, 178 are Steam projects, including the Duri Field in Indonesia. Steam injection for HO recovery has been in use for many years in Canada, Brazil, United States and Venezuela.

However, steam flooding has not been applied in Nigeria. This paper seeks to study the application of steam 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 will be 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.

1.5 Screening Criteria for Some EOR Methods

Taber [16] 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 used in EOR candidate selection. He summarized his findings in the Table 2.

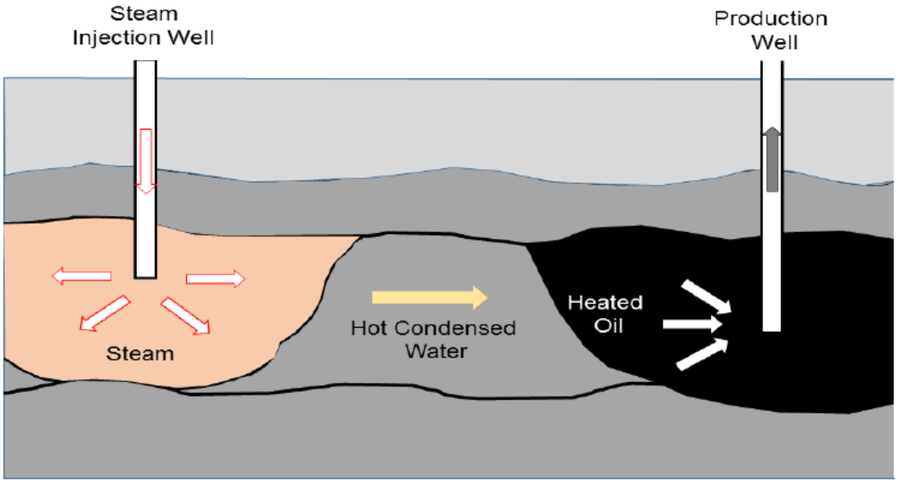

Fig. 3. Mechanism of steam flooding process (Wei Z, 2016)

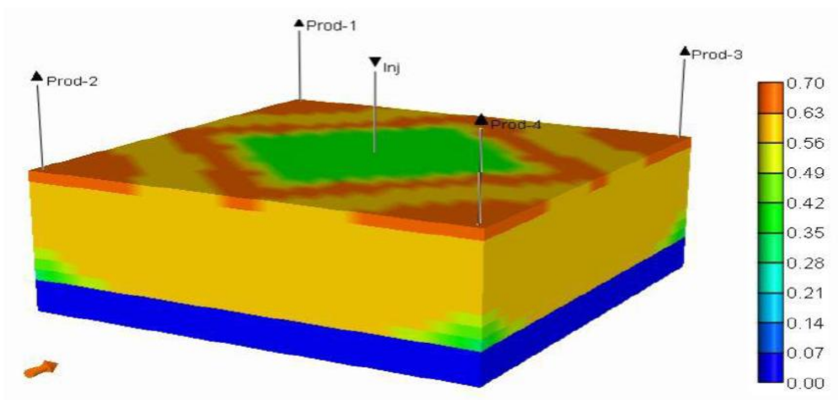

Fig. 4. Steam flooding in an inverted 5-spot grid (CNPC, 2011)

Table 2. Screening criteria

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 normally	<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*

Galvao *et al*, [17] analysed the influence of steam injection rate, injected solvent volume and solvent type on heavy oil recovery using data from a Brazilian reservoir as case study. He discovered that higher steam injection rate and the injection of some surfactant can increase recovery.

Holcomb [18] worked on the economic evaluation of steam injection projects. He developed a computer program called ESIP – Economic Steam Injection Program. This was a simplified program that can calculate NPV, Payback Period and IRR. It was a good program, but it was done in FORTRAN 77 which is not very interactive and now obsolete.

2. MATERIALS AND METHODS

2.1 Methodology

The workflow below shows how the study was conducted.

Fig. 5 above shows the workflow of our methodology: The steps are explained below. Following the discovery and appraisal of any field, some data such as seismic data, core data, well logs and well test data 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 above.

As stated earlier, two datasets were received following a Non-Disclosure Agreement (NDA) with 2 companies that have heavy oil reservoirs in their assets.

For one company, the concession was offshore, and we called it Reservoir A, while the other asset was in the onshore terrain, and we called it Reservoir B. 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 for sandstone reservoirs was adapted from the works of Taber et al [19] for the reservoirs in Nigeria to assess the characteristics of the reservoirs of interest (Reservoirs A & B) and their fluid properties to determine what EOR technique was suitable for them. The data for Reservoir A is presented in Table 3.

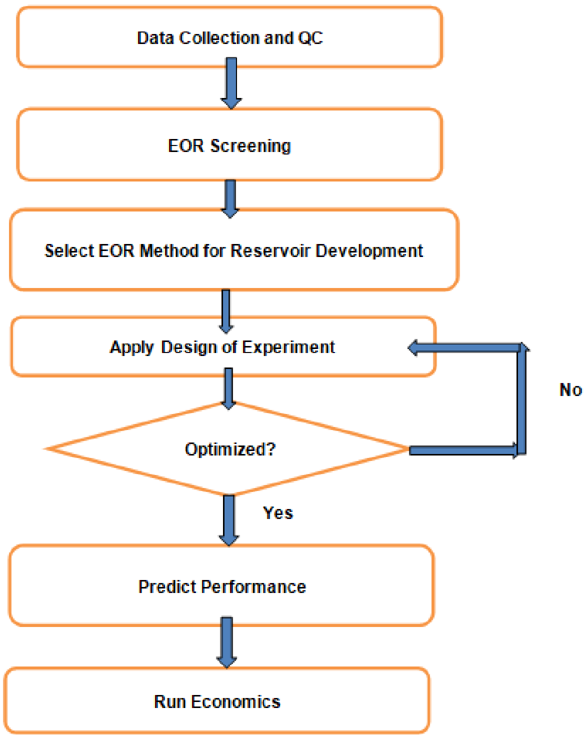

Fig. 5. Workflow of the methodology

Table 3. Study reservoir data (average values): 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	13.9
Reservoir Depth	ft	2,621
Net pay thickness	ft	100
Oil Saturation	%	0.9
Porosity	fraction	0.3

Now based on the relevant data acquired from Reservoir A as stated in Table 3, we applied the screening criteria to select a suitable EOR technique for the development of the reservoir.

We found that the recommended EOR methods for the development of HO from Reservoir A are Polymer Flooding, In Situ Combustion (ISC) and Steam Flooding. ISC was not pursued because of safety considerations as it involves putting fire inside the reservoir. This study is focused on the application of Steam Flooding. The idea of introducing the screening criteria was to justify the selection of Steam Flooding for the reservoirs in consideration.

Following the selection of the suitable EOR method for the reservoir, some statistical tools were used to design an experiment, get optimum values to feed into the numerical reservoir simulation model to predict performance and then run the economics afterwards.

2.2 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 [20]. 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 are manipulated to determine their effect on measured response variable. It also provides a guide as to which factors should be considered important, as there could be many factors [21].

In this work, Response Surface Methodology (RSM) which is an application of DOE was employed to understand how the parameters of interest and their interactions in Steam Flooding affect the cumulative oil produced. In addition, it was also used to estimate the optimal values for the parameters of interest to maximize recovery. The dependent variable was cumulative oil production, while the independent variables were the factors that affect oil production from steam flooding.

For the steam flooding, we thought the cumulative production was a function of nine (9) major variables as stated in the equation (1) below:

$$\mathrm{FOPT} = \mathrm{f}\left(\emptyset, \mathrm{K_e}, \frac{\mathrm{K_v}}{\mathrm{K_h}}, \mathrm{S_{ir}}, \mathrm{S_q}, \mathrm{S_{ip}}, \mathrm{t}, \mathrm{S_{it}}, \mathrm{C_l}\right) \quad (1)$$

Where:

FOPT = cumulative oil production in bbls,
$\mathrm{S_{ir}}$ = steam injection rate in $\frac{\mathrm{stb}}{\mathrm{d}}$,
$\mathrm{S_q}$ = steam quality in % ,
$\mathrm{S_{ip}}$ = steam injection pressure in psia,
$\mathrm{S_{iT}}$ = steam injection temperature in F,
t = time in years,
$\mathrm{C_L}$ = completion layer,
$\emptyset$ = porosity in %,
$\mathrm{K_e}$ = effective permeability in mD, and
$\mathrm{K_v}/\mathrm{K_h}$ = permeability anisotropy

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 can become a first pass diagnostic tool for HO recovery.

2.3 Reservoir B

We also considered another reservoir (Reservoir B) in an onshore Niger Delta field. Based on the application of EOR screening criteria which was like Reservoir A, we applied the same EOR screening techniques to get Steam Flooding for this case too. 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. Natural depletion as well as steam injection were considered and thereafter, the economics was evaluated for the deterministic model based on the current fiscal regime.

2.3.1 Reservoir B performance prediction

Based on the diagnostic tool developed from DoE in this research work, the performance of Reservoir B was predicted using the tool. Reservoir simulation was then used to validate the predictions from the diagnostic model equations for reservoir performance using steam flooding. Afterwards, the economics of the process was analyzed. The use of statistical tools like error bars was employed to examine the spread and predictive capacity of the model equation, and to test how robust the diagnostic model is.

2.4 Economic Evaluation

We applied the use of 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. Tables 4 & 5 show the input parameters for the economic model.

The input data for reservoir A varies from that 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.

3. RESULTS AND DISCUSSION

3.1 Result of Design of Experiment for Steam Flooding

Several factors must be considered in the application of steam injection to ensure an efficient flooding process. Some of these factors are reservoir based, while others have to do with the control parameters the operator has to decide on. In all, the bottom line is that the best of these parameters must be chosen to ensure a successful operation that would minimize formation damage. In view of that, an understanding of the interaction of these parameters is key. We therefore deployed RSM to establish these interactions and to ascertain the optimum combination of the parameters.

We used possible range of values based on what we know of the Niger Delta reservoirs and the steam flooding process in Canada, Southern California, and Venezuela. The parameters considered include porosity, average reservoir permeability, permeability anisotropy, steam injection rate, injection pressure, injection temperature, steam quality, well completion layer and the duration of flooding operation. A summary of the range of values is shown in Table 6.

The use of regression analysis to model responses to variation of certain identified parameters has been widely accepted today. Equation 2 shows the model for the cumulative oil produced based on our experimental runs using DoE tools as discussed above.

Equation 2 could serve as a diagnostic tool for performance for steam flooding in heavy oil reservoirs in the Niger Delta. Table 7 shows a summary of the model statistics. Statistical testing of the model was performed in the form of analysis of variance (ANOVA). The quadratic regression model showed the value of coefficient of determination (R^2) of 0.9955 with no significant lack of fit at $p > 0.05$, which means that the calculated model was able to explain 99.55% 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.

Table 4. Input parameters for deterministic model for Reservoir A (shallow field) - Steam 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	859	$M
Variable OPEX	3%	of gross revenue per year (Rule of Thumb)
Field OPEX	5%	of CAPEX (Rule of Thumb)
Field life	23	years
Initial production rate	3550	bbls/day
Peak production rate	4000	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 5. Input Data for Reservoir B Steam Flooding - Onshore Field (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	458	$M
Variable OPEX	2%	of gross revenue per year
Field OPEX	3%	of CAPEX
Field life	21	years
Initial production rate	8000	bbls/day
Peak production rate	8000	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 6. Range of parameters for thermal experimental runs

Factor	Unit	Low	High
Permeability	mD	1500	3000
K_v/K_h	%	10	60
Steam injection rate	STB/D	100	1500
Steam quality	%	10	80
Injection pressure	Psia	3000	6000
Time	Yr	5	35
Injection temperature	F	150	600
Completion layer		1	5
Porosity	%	28	33

$$FOPT = -0.61S_{ir}^2 + 351S_q^2 - 0.101S_{ip}^2 + 2.9S_{iT}^2 - 15,906t^2 - 136,366C_L^2 - 79,703\emptyset^2 - 0.319K_e^2 - 447\,{K_v/K_h}^2 + S_{ir}\left[-5,357 + 0.579K_e - 10.2\,K_v/K_h + 28.5S_q + 0.174S_{ip} + 139.7t + 2.97S_{iT} + 1.88C_L + 49\emptyset\right] + S_q\left[121,125 + 2.51K_e + 29\,K_v/K_h + 4.92S_{ip} + 1,045t - 17.1S_{iT} + 2,447C_L + 1,322\emptyset\right] + S_{ip}\left[108 - 0.25K_e - 4.27\,K_v/K_h + 4.69t - 0.14S_{iT} + 11.6C_L + 41.8\emptyset\right] + S_{iT}\left[-17,353 - 0.48K_e + 12.8\,K_v/K_h + 53.7t + 58C_L + 542\emptyset\right] + t\left[488,351 - 40K_e - 316\,K_v/K_h + 3,567C_L + 13,004\emptyset\right] + C_L\left[3,354,507 - 107K_e - 1,088\,K_v/K_h - 85,553\emptyset\right] + \emptyset\left[4,721,962 - 43.5K_e - 1,590\,K_v/K_h\right] + K_e\left[6,400 - 5.49\,K_v/K_h\right] + 122,472\,K_v/K_h \quad (2)$$

Table 7. Model statistics summary for thermal flooding

R-sq.	R-sq. (Adj)	F-value	P-value
99.55%	97.13%	41.17	0.001

The significance of the model was also judged by *F*-test, which suggested that model had a high model *F*-value (F = 41.17). R^2adj, adjusted coefficient of determination, is the correlation measure for testing the goodness-of-fit of the regression equation [22]. The R^2adj value of this model is 0.9713, which indicated that only 2.87 % of the total variations were not explained by model.

Moreso, a normal probability plot shown in Fig. 6 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.

With the optimal conditions determined using RSM, we proceeded to run the reservoir simulation model. The results which include those of stem injection, polymer flooding, natural depletion and water flooding is shown in the Fig. 7 and Table 8, which shows that steam flooding gave a higher recovery efficiency, followed by polymer flooding, water flooding, and then natural depletion.

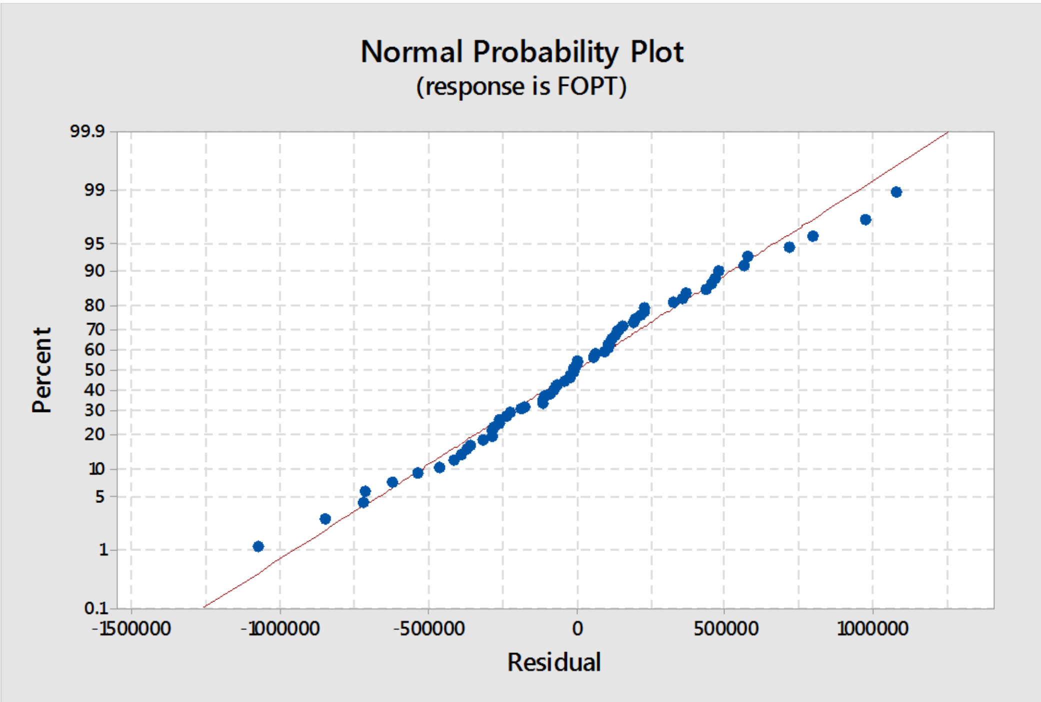

Fig. 6. Normal probability plot

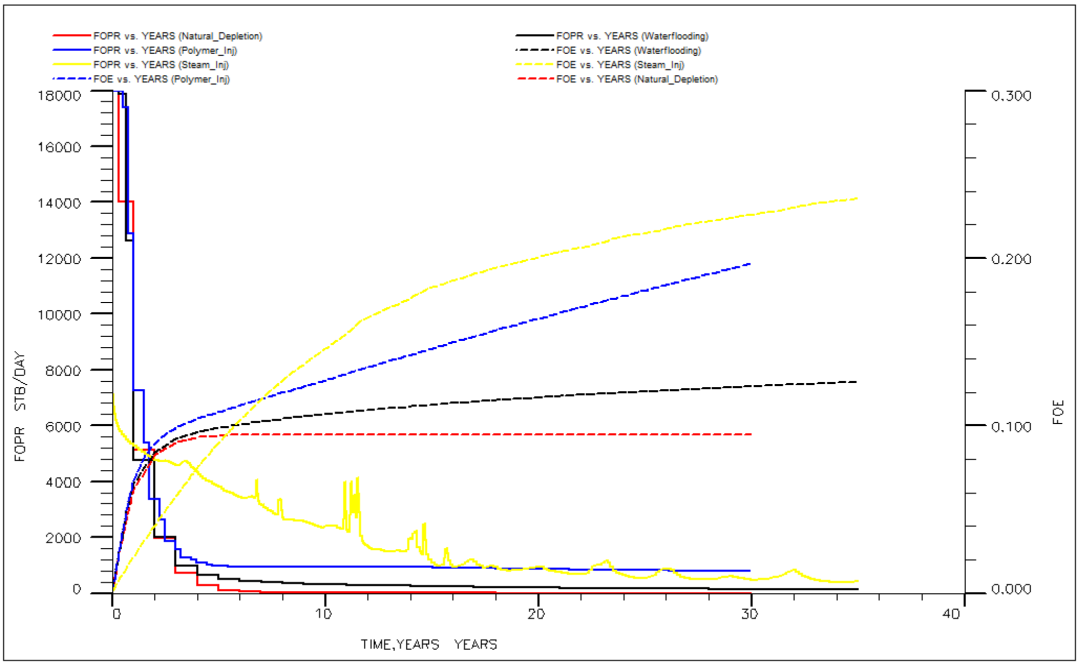

Fig. 7. Comparison of natural depletion, waterflooding, polymer flooding and steam flooding in terms of recovery efficiency

Table 8. 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

3.1.1 Reservoir B

Reservoir B is in an onshore field with the average properties presented in Table 9 below:

As in the previous case, the reservoir and fluid properties fell into the same band when we applied the screening criteria for EOR selection. Therefore, reservoir B can also be better developed by using steam flooding. This was applied for performance prediction and validation of the diagnostic tool that we developed in this research work, using the Design of Experiment.

Table 9. 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	12.8
Reservoir Depth	ft	2,970
Net pay thickness	ft	49
Oil Saturation	%	0.85
Porosity	fraction	0.3

3.1.2 Prediction of reservoir B performance using the diagnostic tool

The diagnostic model (Eqn. 2) was applied to the range of values of the Reservoir B and the operational parameters. This implies that random values of porosity, permeability, steam injection rate, steam quality, steam injection pressure, steam injection temperature, time, completion layer, K_v/K_h, 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 exported that data into our reservoir simulation model. We then ran sensitivity on our simulation model using the values that were imputed in the diagnostic model. We analyzed the response from the diagnostic model equation (Equation 2) and reservoir simulation as well as the difference.

Fig. 8 shows the field oil recovery efficiency for the natural depletion, polymer injection (model not shown in this paper) and steam injection models of reservoir B, and as shown in the figure, the natural depletion could only attain 3.5 % recovery. However, with the implementation of polymer and steam injections, a recovery of 9.07 % and 19.7 % respectively were obtained.

Also, as seen from the Fig 8 and Table 10, a higher recovery efficiency is attained by steam injection compared to polymer injection and natural depletion. This can be attributed to the viscosity reduction as well as a better pressure maintenance capability of steam.

3.1.3 Diagnostic model validation

The diagnostic model was validated by comparing its result with that of reservoir simulation for steam flooding to establish its robustness as well as its level of accuracy in prediction.

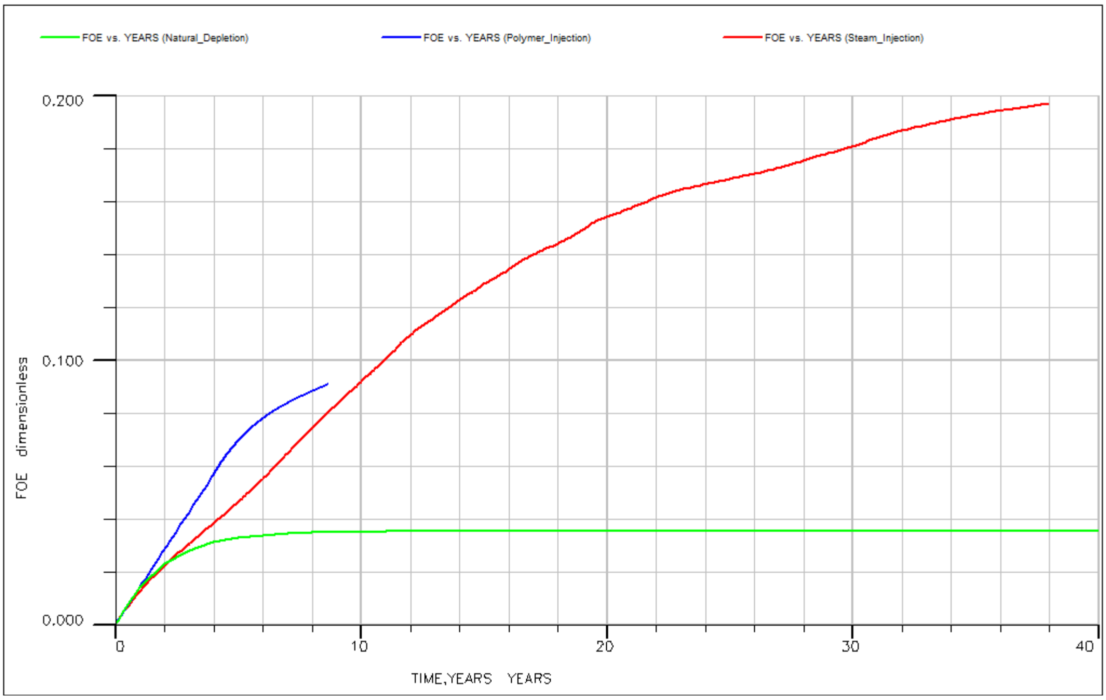

Fig. 8. Field recovery efficiency for B reservoir

Table 10. Summary of performance prediction of various recovery techniques

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

The values of cumulative oil production obtained from the diagnostic model and that obtained from reservoir simulation were compared and plotted as shown below. The difference between the values of cumulative oil production obtained from the two models gives the error bars. The error bars are shown in the Fig 9, and they illustrate how close the predictions were, or conversely, how far from the reported value the true (error free) value might be. The error bars also represent one standard deviation of uncertainty, one standard error or a confidence interval. From the trends of the several experimental runs, the error within the prediction was low (less than 5%) thus signifying a near accurate prediction by the diagnostic tool. That was a validation of the diagnostic model equation.

3.2 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 profiles 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 HO using steam injection remained profitable. The details of the results are discussed in the sections below:

3.2.1 Deterministic results for Reservoir B and Reservoir A for different HO prices

The deterministic model was built with heavy oil price of $20/bbl as base case heavy oil price, $15/bbl was used as worst-case scenario while $25/bbl was used as best-case scenario. This is because heavy oil price is usually discounted by 30% to 50% conventional oil price. Tables 11, 12 and 13 show that the heavy oil field projects for reservoirs A and B, produced using steam injection recovery methods were found to be profitable.

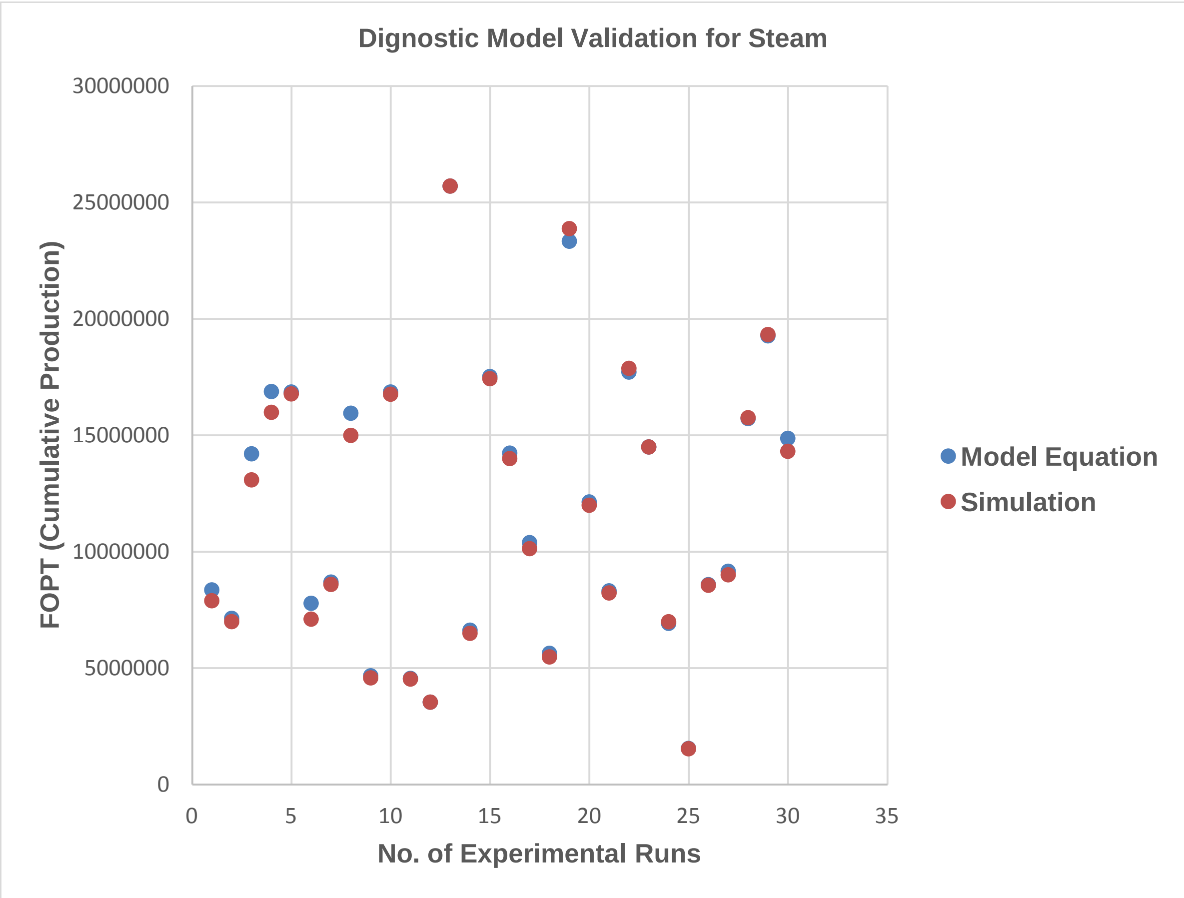

Fig 9. Diagnostic model validation for steam flood

From the profitability analysis, 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 50 MMstb 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 done with varying heavy oil price as $15/bbl, $20/bbl and $25/bbl shows an all-profitable heavy oil field project.

Table 11. Profitability analysis at $20/bbl heavy oil price (Base Case)

	Reservoir b	**Reservoir a**
Economic Indicators	**Steam Injection**	**Steam Injection**
Discount Rate (%)	15	15
Internal Rate Of Return (%)	37%	35%
Net Present Value ($M)	44,255.44	36,421.14
Unit Technical Cost ($/Bbl)	1.21	1.27
Unit Capex ($/Bbl)	0.02	0.048
Unit Opex ($/Bbl)	1.19	1.22
BFIT ($M)	150,293.80	394,704.92
AFIT ($M)	44,255.44	36,421.14
Payback Period (Years)	> 2years	>2 years

Table 12. Profitability analysis at $15/bbl heavy oil price (worst case scenario)

	RESERVOIR B	**RESERVOIR A**
Economic Indicators	**Steam Injection**	**Steam Injection**
Discount Rate (%)	15%	15%
Internal Rate Of Return (%)	30%	34%
Net Present Value ($M)	27,185.63	27,185.63
Unit Technical Cost ($/Bbl)	0.96	0.96
Unit Capex ($/Bbl)	0.048	0.048
Unit Opex ($/Bbl)	0.92	0.92
BFIT ($M)	296,028.69	394,704.92
AFIT ($M)	27,185.63	27,185.63
Payback Period (Years)	> 2years	>2 years

Table 13. Profitability analysis at $25/bbl heavy oil price (best case scenario)

	Reservoir B	**Reservoir A**
Economic Indicators	**Steam Injection**	**Steam Injection**
Discount Rate (%)	15%	15%
Internal Rate of Return (%)	30%	34%
Net Present Value ($M)	55,397.64	27,185.63
Unit Technical Cost ($/Bbl)	1.51	0.96
Unit Capex ($/Bbl)	0.020	0.048
Unit Opex ($/Bbl)	1.48	0.92
BFIT ($M)	599,797.47	296,028.69
AFIT ($M)	55,397.64	27,185.63
Payback Period (Years)	> 2years	>2 years

3.3 Major Findings

1. Although steam flooding is capital intensive because of the facilities required for steam generation and continuous injection, the economics shows that the process is viable for the reservoirs considered even for a low heavy oil price of US$15, because of improved recovery efficiency.
2. If the current fiscal regime in Nigeria is adjusted to lower the tax from 85% to say 50%, that can be an incentive to investors to apply steam flooding for HO reservoirs that meet the selection criteria.

4. CONCLUSIONS & RECOMMENDATION

The following conclusions and recommendations were reached in the study conducted:

4.1 Conclusions

1. Steam injection technique if applied to HO reservoirs that meet the selection criteria has the potential to increase oil reserves and production in Nigeria.
2. Design of Experiments (DoE) can be used to determine the optimum values of the reservoir and operating parameters for HO recovery using Steam flooding.
3. A diagnostic model that has the capacity to predict HO recovery in the Niger Delta when steam flooding technique is applied was developed.
4. Steam flooding was economically viable for the reservoirs considered and can be applied to other HO reservoirs that meet the selection criteria.

4.2 Recommendation

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.

DISCLAIMER

The products used for this research are commonly and predominantly use products in our area of research and country. There is absolutely no conflict of interest between the authors and producers of the products because we do not intend to use these products as an avenue for any litigation but for the advancement of knowledge. Also, the research was not funded by the producing company rather it was funded by personal efforts of the authors.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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