Design Mechanism for Waterflooding in a Reservoir

(A case study of a Niger Delta reservoir)

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Abstract

A dynamic reservoir simulation was performed using Eclipse (PETREL) to investigate the application of sound waterflood design principles to a Niger delta oil field. To ascertain contributions of the different schemes and techniques applied in selecting the best appropriate waterflood design, a case of recovery by natural depletion was first considered. This recovery approach, after all possible optimizations, the final EUR obtained was 28.76% with two new added wells, B1 and C2. Adding a third well could only raise it to 29.4%. Recovery is improved by shutting off completions in the water zone, watered out producers and deviation of old wells. This shows that a lot can still be squeezed out of the field, recommending it for secondary and enhanced oil recovery, implying the need for additional recovery by secondary and enhanced oil recovery technologies. The numerical reservoir model was subsequently examined under different cases to optimize a secondary recovery water scheme. Optimized parameters included critical gas saturation, well placement, plateau production and injection rates, and well completion. Sensitivity analysis was also performed with respect to these optimization constraints. This gave a recovery factor of 52.23%, with the plateau rate of 7400 Sm^3/d sustained for 4 years as required.

Keywords: Design mechanisms; Waterflooding; Reservoir; Enhanced Ultimate Recovery; Design parameters.

1.0 INTRODUCTION

The primary and principal reason for water flooding an oil reservoir is to increase the oil-production rate and, ultimately, the oil recovery. This is accomplished by "voidage replacement"—injection of water to increase the reservoir pressure to its initial level and maintain it near that pressure. The reservoir energy is the primary force that displaces or drives the reservoir fluid (oil) existing at high pressure into the wellbore and finally into the surface facilities. The initial pressure of the reservoir drops below economic limits while the response of the reservoir to depletion is dynamic and the manner in which the reservoir responds to depletion is governed by the drive mechanism.

The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive (secondary or enhanced oil recovery project), most basic methods being the injection of gas or water.

Over the years, from the early days of oil production up to early 1930's most of the reservoirs were produced by the primary reservoir energy down to an economic rate. At this point, an additional energy is required to lift the fluids. The secondary recovery process starts when primary energy has been exhausted or while the primary energy is still producing. Some enhanced oil recovery process include gas injection, water flooding, steam injection, microbial methods and chemical flooding. Tertiary oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. The choice of this EOR project is dependent on so many factors but here we will limit our study to waterflooding as the secondary or EOR project to be used.

Being considered as a secondary recovery process whereby clean non-corrosive water is injected into the area surrounding the reservoir to supplement the natural energy produced by the reservoir to force the remaining oil within the reservoir rock formation to the producing wellbore and to improve the oil producing characteristics of the field after the economical productivity limit s are reached. This involves injection of water through wells specially set up for water flooding and the removal of water and oil from producing wells drilled adjacent to the injection wells. This practice is accepted worldwide as the most common, reliable and

economic recovery technique. Before this waterflooding project will be implemented a preliminary well design which will act as the blue print will be designed by the petroleum engineer. Before this design is carried out, the petroleum engineer have to understand what makes the well a candidate for waterflooding, the geological factors influencing the well and the reservoir properties etc (Willhite 1986).
When the natural energy of the down structure reservoir has been used up and considered marginal by Exploration and Production (E&P) companies, substantial amounts of oil may still be left in the basement of the reservoir; as a result, these companies abandon such reserves due to the uncertainty concerning the best and most economical technique of recovering such down structure reserves. This problem of oil not being able to move to the well perforations is as a result of no or partial aquifer influx and /or rapid pressure decline in the reservoir.
This work is aimed at designing and optimizing a waterflood scheme in a complex reservoir system using Eclipse to investigate a sound waterflood design principle. It tends to justify the objective of performing a preliminary natural depletion simulation, designing a waterflood based on voidage replacement principle, optimizing well locations and perforations to maximize recovery, optimize sensitive reservoir parameters like optimize production / injection rates to meet management constraints while maximizing recovery.

2.0 Materials and Methods

2.1 Materials

The following data are required

- PVT Data
- Initial Reservoir Pressure
- Average Reservoir Pressure History
- Production History
- Simulator

2.2 Methods

- Material Balance Analysis
- Reservoir Simulation (ECLIPSE)

2.2 Methods

The research tends to build an Eclipse model for a Niger delta oil field and its adaptation, well design and Simulation using the ECLIPSE software.

2.2.1 Recommended Steps in Waterflood Design

The recommended design steps presented in [9] provides a basis for this study and is hence adopted; these steps are as follows;

1.0 Construct a Geologic Model of the Reservoir or Project Area.

- Identify and include all faults and other structural features that may affect fluid flow in a geologic frame work model of the reservoir.
- Identify and include all reservoir heterogeneities, such as permeability barriers, reservoir unconformities, etc. in the geologic model.
- Perform characterization of the geologic model to include areal and vertical variation of reservoir properties such as facies, net pay, porosity, permeability, and saturations.

2.0 Analyze Rock/Fluid Properties Data.

- Determine mineralogy of reservoir rocks
- Conduct studies on compatibility of injection water with reservoir rocks.
- Determine PVT properties of reservoir fluids, including saturation pressures and oil viscosity.

3.0 Construct Reservoir Flow Model with Data Obtained Geologic and Reservoir Data

If the reservoir had prior production history, history-match reservoir model to obtain the current depleted state of the reservoir before the start of waterflooding. At the completion of the above statement, determine gas cap size if a gas cap is present and extent of aquifer influx if reservoir has an active aquifer. Compare pressure distribution in model after history match to actual pressure data. Identify state of reservoir depletion. Explore distribution of fluid saturation in the model after history match to identify potential undepleted areas of the reservoir that would be targets for waterflooding.

4.0 Run prediction cases

Run a base prediction case assuming continuation of current depletion strategy. Run several predictive cases assuming the reservoir is waterflooded with different numbers and locations of water injectors and producers. Compare results obtained from above. If the waterflood cases indicate substantial improvement in total oil recovery, then proceed to design optimization.

5.0 Optimize Waterflood Design.

- Choose the cases from the preceding step with the "best" reservoir performance and optimize the numbers and locations of injectors and producers.
- Optimize injection and production rates for each case. Rank the cases by incorporating project economics.

6.0 Perform Sensitivity Analysis

Select two or three cases from design optimization and perform sensitivity analyses on key reservoir and operational variables of the waterflood design. Repeat economic analyses of the entire project based on results from the step above.

2.3 Reservoir Modelling Methodology

The reservoir model will be built using PETREL®. The sequence to be followed primarily involves

- Building geological reservoir model
- Perform QC on Model
- Run simulation of production achievable from primary recovery
- Perform injection well design in Petrel for selected waterflood pattern

Sensitize results on well design parameters

2.3.1 Reservoir modeling

Building the reservoir model basically entails the recommended sequence for building static models in Petrel. The sequence is outlined below:

- Data import and qc of input
- Well to Well Correlation
- Fault modelling
- Pillar gridding
- Make horizons
- Depth conversion
- Make zones
- Layering
- Geometrical property modeling
- Scale up well logs
- Facies modeling
- Petrophysical modeling
- Defining fluid contacts
- Volume calculation

2.3.2 Reservoir Model and Characteristics

A reservoir simulation model was designed to investigate the production capacity of a case study reservoir. The reservoir model was built using the four appraisal wells: A2, A4, N2 and N3. These wells can be abandoned according to the production scheme.

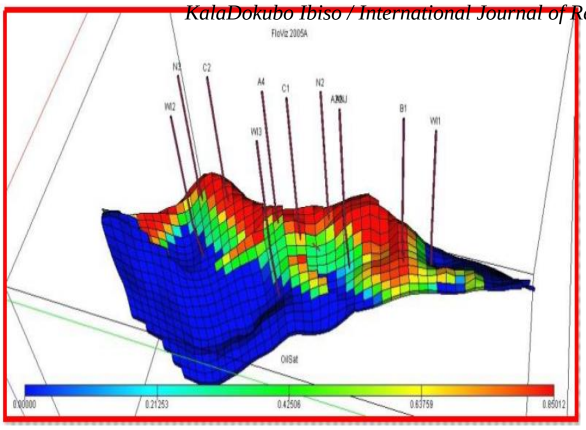


Figure 1: 3D Reservoir Model Showing the Grids

A Black Oil model was designed with rectangular cells with 36 cells along the x-direction and 51 cells along the y- direction. The geometry definition is given in a Petrel file: 'MODEL_PETREL.GRDECL'. The structural framework used for the Corner Point Geometry is based on the Spinal Fault Geometry and the North fault limit. Model size is geometrically 36x51x18 but is in reality 36x51x17.

For this study, the reservoir is split into 17 layers (along the z axis) for ease of simulation runs. There are three equilibration regions defined in the EQUNUM keyword in the Regions section, but two regions are mainly oil-bearing. However, there is no evidence of compartmentalization; all the regions have the same water-oil-contact (WOC).

2.3.3 Formulations of Black Oil Flow Equation

Using the Darcy's equation the black oil flow equations are:

Oil

$$\nabla\left[\frac{k k_{ro}}{\mu_o B_o}\left(\nabla p_o - \gamma_o \nabla z\right)\right] + \frac{\bar{q}_o}{\rho_{oSC}} = \frac{\partial}{\partial t}\left(\phi \frac{S_o}{B_o}\right) \quad (1)$$

Water

$$\nabla\left[\frac{k k_{rw}}{\mu_w B_w}\left(\nabla p_w - \gamma_w \nabla z\right)\right] + \frac{\bar{q}_w}{\rho_{wSC}} = \frac{\partial}{\partial t}\left(\phi \frac{S_w}{B_w}\right) \quad (2)$$

Gas

$$\nabla\left[\frac{kk_{rg}}{\mu_g B_g}\left(\nabla p_g - \gamma_g \nabla z\right) + \frac{kk_{ro}}{\mu_o B_o} R_{so}\left(\nabla p_o - \gamma_o \nabla z\right) + \frac{kk_{rw}}{\mu_w B_w} R_{sw}\left(\nabla p_w - \gamma_w \nabla z\right)\right]$$
$$+ \frac{\bar{q}_g}{\rho_{gSC}} = \frac{\partial}{\partial t}\left[\phi\left(\frac{S_g}{B_g} + \frac{S_o}{B_o} R_{so} + \frac{S_w}{B_w} R_{sw}\right)\right] \quad (3)$$

Material balance Analysis

For an oil reservoir, the general Material Balance Equation accounting for cumulative water and gas injection is expressed as:

$$N_p[B_t + (R_p - R_{soi})B_g] + W_p B_w - W_i - G_i B_{ig}$$
$$= N\left[(B_t - B_{ti}) + B_{ti}(1+m)\left(\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right)\Delta \bar{p} + \frac{mB_{ti}}{B_{gi}}(B_g - B_{gi})\right] + W_e$$

(4)

For a gas reservoir, the Material Balance Equation is expressed by:

$$G(B_g - B_{gi}) + GB_{gi}\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta \bar{p} + W_e = G_p B_g + B_w W_p \quad \textbf{(5)}$$

In gas reservoirs, $c_w \approx 0$, $c_f \approx 0$. Therefore Equation 5 reduces to:

$$G(B_g - B_{gi}) + W_e = G_p B_g + B_w W_p \quad \textbf{(6)}$$

The drive indices for the various drive mechanisms, that is, depletion drive, segregation (gas cap) drive, water drive and connate water and rock expansion (formation) drive, were estimated using Equations 3.3 through 3.6:

$$I_{DD} = \frac{N(B_t - B_{ti})}{N_p\left[B_t + (R_p - R_{soi})B_g\right]} \quad \textbf{(7)}$$

$$I_{SD} = \frac{\frac{NmB_{ti}}{B_{gi}}(B_g - B_{gi})}{N_p\left[B_t + (R_p - R_{soi})B_g\right]} \quad \textbf{(8)}$$

$$I_{WD} = \frac{(W_e - W_p B_w)}{N_p\left[B_t + (R_p - R_{soi})B_g\right]} \quad \textbf{(9)}$$

$$I_{FD} = \frac{(1+m)NB_{ti}\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta p}{N_p\left[B_t + (R_p - R_{soi})B_g\right]} \quad \textbf{(10)}$$

The model governing the flow of fluids in porous media is developed based on a combination of 3 models. These models introduce inherent assumptions and are modified at certain steps to minimize the propagation of the errors associated with these assumptions. The models are as follows:

1. Conservation equation:
   mass rate in – mass rate out = mass rate storage – mass rate reaction
   mass stored in the pore volume = fluid density x pore volume = $\rho \varnothing A \Delta x$
   mass rate storage =
2. Transport (Darcy's) equation: where
   $q = Au$ is referred to as continuity equation
3. Equation of state: This introduces the fluid density into the continuity equation to specify the condition of the reservoir fluid phase. The resultant equation is the fluid flow equation

3.0 RESULTS AND DISCUSSION

The numerical reservoir model is examined under different cases to implement two different production schemes with the aim of production optimization.

Scenario 1: Natural depletion scheme
Scenario 2: Water Injection scheme
Scenario 3: Well Placement

3.1 Scenario 1: Natural Depletion Scheme

The reservoir model is simulated for hydrocarbon production by the natural energy inside the reservoir with the aid of different drive mechanisms such as the solution gas drive, rock and connate water expansion, water drive, and consequently as the pressure drop below bubble point, secondary gas drive.

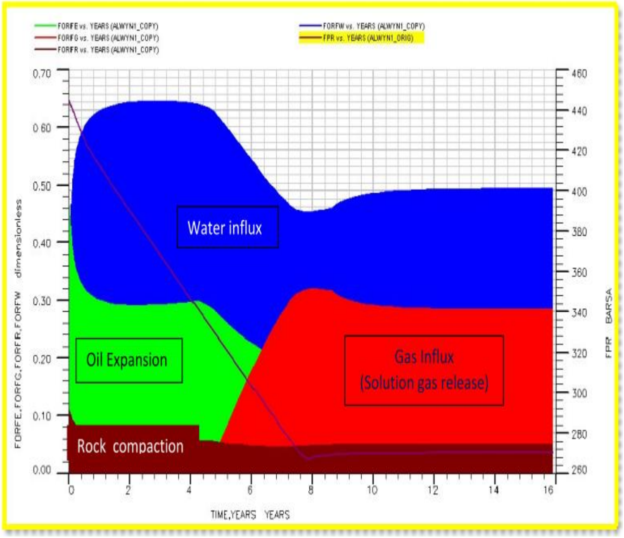


Figure 2: Reservoir Drive energies from Eclipse

The model is run from an initial reservoir pressure of 446 bars to about 258 bars (Bubble point pressure). Drawdown was given to be 30bar. Initially, there were four appraisal wells (A2, A4, N2, and N3).

Material Balance Analysis

Case One: Natural Depletion to Bubble point pressure, (P_b = 3770.98 psi)

This scenario investigates the recovery from the field under the Natural depletion. As the Field was initially undersaturated at discovery, the predominant energies at play are the solution gas drive, fluid expansion and presumed water influx. Their respective contributions are estimated using the General Material Balance Equation, Thus implies that 12.9% of the fluid in place is recoverable by natural depletion down to 100 bars before water injection. This means that one well will be enough to deplete the reservoir. This is practically impossible. However, it is an underlying error to which material balance analysis is susceptible owing to its lack of spatial properties variation considerations (i.e., zero – dimensional).

3.1.2 Case Two: Water Injection @ 4206.09 psi

This case investigates a scenario in which there is pressure maintenance by water injection to keep the reservoir pressure at 290 bar, allowing a drawdown of 30 bar. This ensures that there is no gas released within the reservoir, keeping the oil less viscous than detrimental. This maximizes recovery with a combination of initial solution gas drive down to 290 bar and subsequent assisted water injection. For this case, the total recovery factor is a composite of the recovery from natural depletion and that from water injection, which gave a result of 50.47%. This shows that there is an added 37% recovery due to water injection with four (4) wells to deplete the reservoir.

3.2.1 Reservoir Simulation with Eclipse®

Natural Depletion to 1450.38 psi

This case presents a scenario in which the reservoir pressure is allowed to drop below Bubble point pressure constrained by a well BHP of 100 bar, allowing the release of the solution gas from the oil within the reservoir.

For the initial run, the field production plateau was raised to 3200 Sm^3/d. It was run with the optimized completion results from Case 1. The results obtained are displayed below.

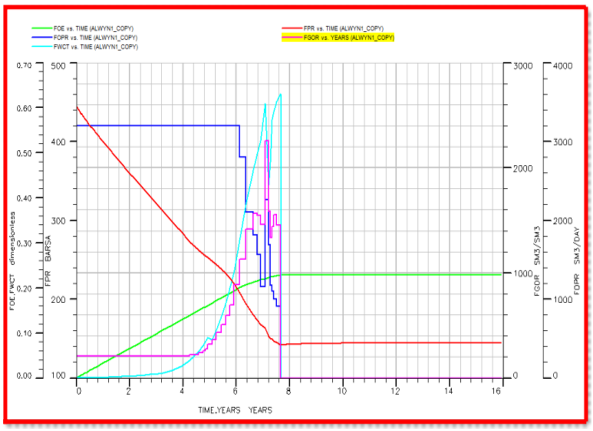


Figure 3: Initial run for Natural Depletion to 1450.38 psi

From the plot, the recovery factor is 22.8%. It is also observed that there is a rapid increase in field GOR and Water cut. The production plateau of 3200 Sm^3/d was sustained for 6 years before declining rapidly. From this plot, it is desirable to optimize the production plateau, adding more wells as may be necessary and possibly changing it with time as the wells become watered out to reduce the effects of water coning.

Water Injection Scenario

A depression is seen in the Field pressure in Figure 3.6 at the moment the GOR starts increasing. This means that release solution gas gets mobile at the instance of release. This is due to the critical gas saturation (S_{gc}) being set at 0% which is theoretically unrealistic as gas globules need to coalesce to reasonable extent before joining the competition for relative permeability. When this value was increased to 10% for the Region 1 and 8.5% for the Region 2, the Field Oil Recovery Efficiency (FOE) increased to 26.84% as shown below.

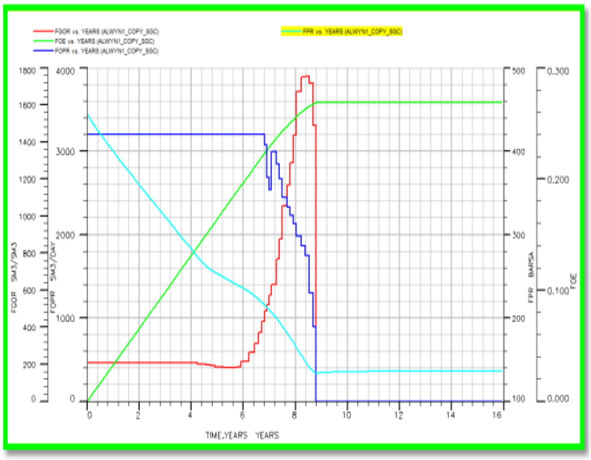


Figure 4: Improved recovery due to Sgc increase to 10% for Region 1 and 8.5% for Region 2

It is also observed that in line with the production constraint, production plateau is maintained for up to 6 years, well above the required 4 years

Well Placement Scenario

It is desirable to ascertain the optimum number of wells needed to drain the reservoir as reasonable amount of oil still remain within the reservoir after the last time step of previous simulation runs.

New 7in wells were drilled into the structure, 2 months after first oil, being placed at areas with large amounts of residual oil. A field production plateau of 4200 Sm^3/d was maintained. Deviated wells (newly drilled and re-completed –A4) were constrained by a production rate of 2400Sm^3/d as per contract specifications while non – prolific producers, re – completed and deviated – N2 and N3 – were constrained to 2000 Sm^3/d.

Case 1:
For the first case, 2 wells B1 and B2 were added. Their placement and resulting production profiles with water cut are shown below.

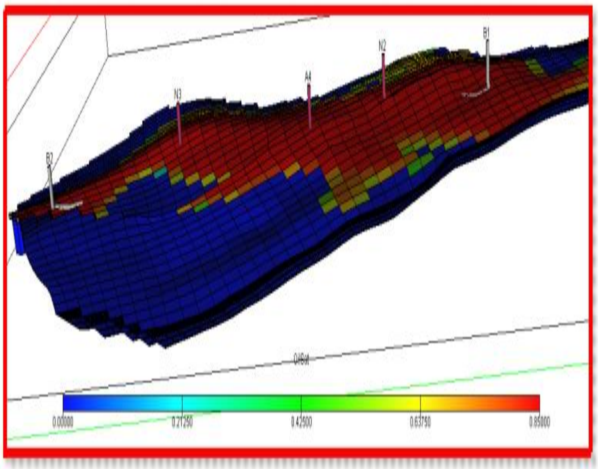


Figure 5: Well placement options: B1 and B2

It is immediately seen that well B2 is a contributor to the overall recovery plan. Also, it is seen that with more wells and deviated well production constraint rose to 2400 Sm^3/d (for prolific) and 2000 Sm^3/d (for non-prolific) maintained plateau beyond 6 years with a Recovery Factor (RF) of 28%.

Case 2:
For the second case, 2 wells, B1 and C were added. Their placement and resulting production profiles with water cut are shown below.

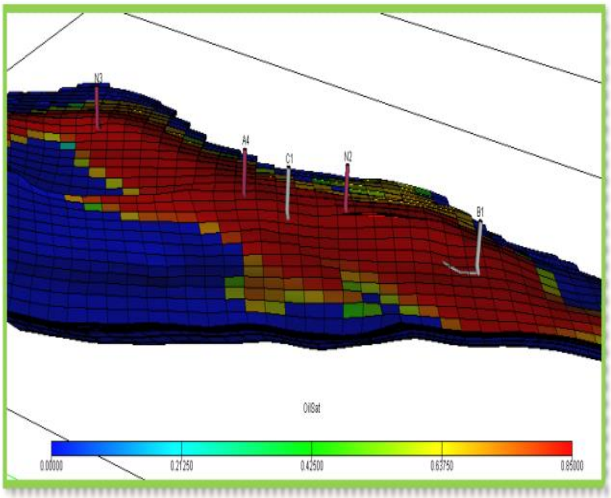


Figure 6: Well Placement Options: B1 and C1

It is immediately observed that there is improved recovery with well C1 than with well B2, though not very much, with a Recovery Factor (RF) of 28.76%

Case 3:
For the third case, 2 wells, B1 and C2 were added. Their placement and resulting production profiles with water cut are shown below.

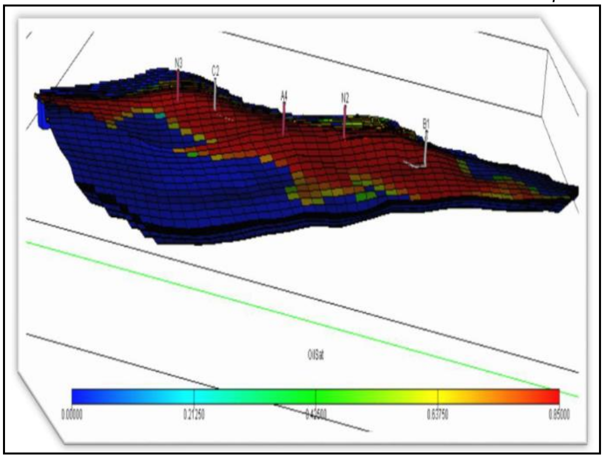


Figure 7: Well placement options: B1 and C2

It can be seen that the addition of well C2 improved recovery to over 29%. It is also a prolific producer with minimal water cut.

Case 4:

After the well placement and deliverability analysis, a configuration having a combination of wells B1, C1 and C2 with a production plateau of 5500 Sm^3/d is tried.

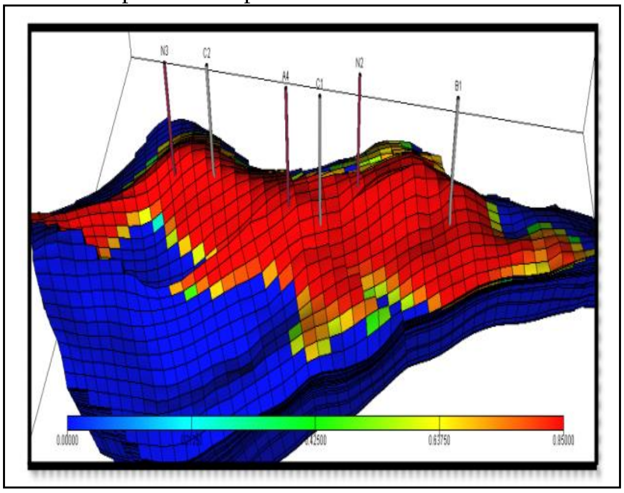


Figure 8: Well placement options: B1, C1 and C2

It can be seen that there is no additional recovery from using 3 wells. There is a good recovery of 28.76% from the case of B1 and C2 alone than with the 3 wells (29.4%) with a higher Field GOR.

Hence, it is recommended that for economic reasons, well C1 be left out for the natural depletion phase as an option for the future.

Well Placement Scenario

The most daunting task in every major injection development design is the accurate placement of wells. Preliminary analysis involved identifies the regions within the field that were production "Sweet Spots" composed of adequate transmissibility and residual oil.

Figure below shows the final well placement for the new wells drilled, both producers and injectors.

Production wells' locations were positioned at good residual oil saturation and Transmissivity (TransX) spots while Injection wells were sited at good Transmissivity (TransZ+). This ensured efficient delivery from these wells as their connectivity was assured.

Also, for injection wells, the Fault transmissivity is checked. Injecting close to the sealing fault is attractive as it aids the sweeping of the oil trapped within those regions. The final well placement chosen, using the recommended peripheral injection pattern with 5injection wells and 7 producer wells, is shown below.

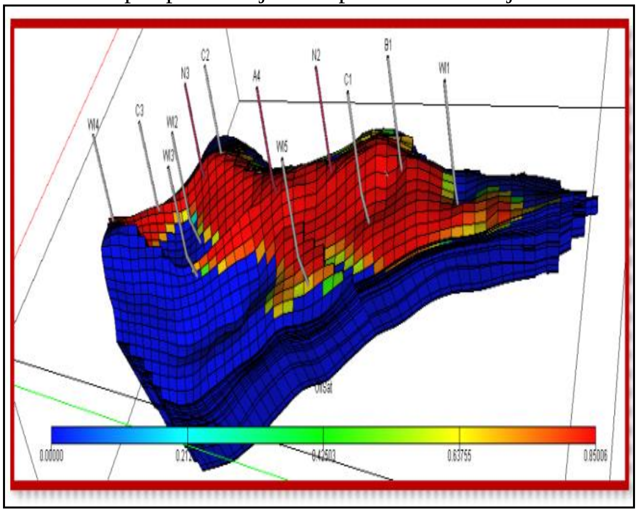
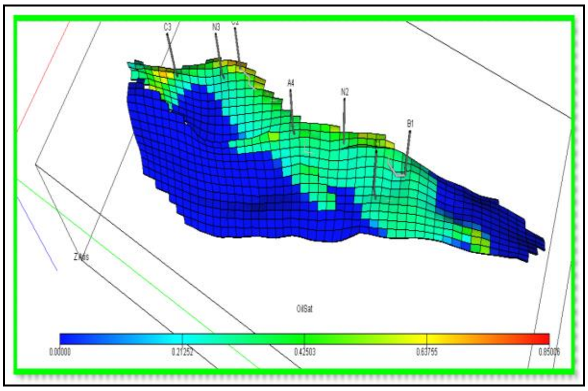
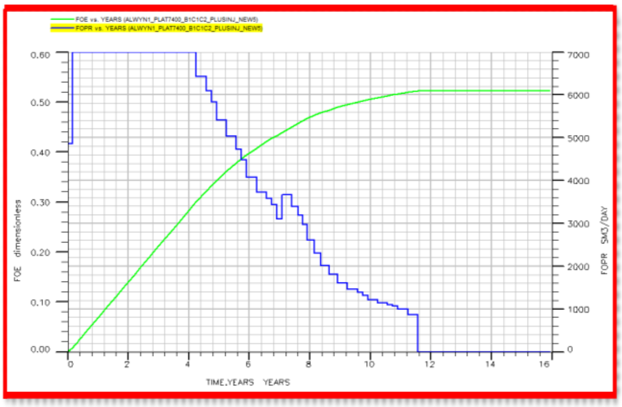


Figure 9: Final Development Pattern with Water Injection Wells Placement

This gave a recovery factor of 52.23%, with the plateau rate of 7400 Sm 3 /d sustained for 4 years as required. The plots below show the completion configuration at the end of the simulation run and the FOE and FOPR plots.



Well Completion configuration on Layer 4 at last time step of simulation run



Field Oil Efficiency and Field Oil Production Rate

TABLE 1: Comparison of Simulation Results for Natural Depletion and Water Injection

RECOVERY FACTOR	**NATURAL DEPLETION**	**WATER INJECTION SCENARIO**
MATERIAL BALANCE ANALYSIS	CASE I: 12.9%	CASE II: 37%
SIMULATION RUN (ECLIPSE)	CASE I: 22.8%	CASE II: 26.84%
WELL PLACEMENT	CASE I: 28% CASE II: 28.76% CASE III: 29% CASE IV: 29.4%	CASE III: 52.23%

4.0 Conclusion

This research has presented a case study of the application of sound waterflood design principles to an oil field in the Niger delta.

- Different case scenarios were considered to ascertain the best and most economic design to achieve and squeeze out residual oil in this field through a proper water flooding scheme.
- From the simulation run, it was deduced that the number of wells selected was able to maintain the voidage replacement requirements, while maintaining their individual injection rate constraint.
- New 5 injector wells were drilled into the reservoir system, being placed at strategic areas with large amounts of residual oil
- Finally simulations were run following each minor decision to ascertain if such decisions were beneficial to recovery or detrimental.

Final results indicated a recovery of 52.23% following the successful water flood design and optimization.

4.1 Recommendations

In summary, this study has presented an approach to water flooding project design. The following recommendations can be drawn from this study;

- Material Balance Analysis is not recommended as a single tool for water flood design, however it gives an indication of the recommended flood pattern.
- In using Reservoir Simulators, injectors are positioned by developing an index or sweet spot parameters that integrates the major parameters that will influence the effectiveness and efficiency of the flood. The ideal parameters recommended are the vertical transmissibility, porosity and distance to faults. This index should be plotted and used as an indicator for best locations for water injectors.

Simulations are only mathematical solutions to real life problems. However, the last step of every such simulation is a field pilot test. In the lowest case, a laboratory scale test could be acceptable.

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