

Research Article

Modelling and Simulation of a 3-D Reservoir for Enhanced Oil Recovery of 'X' Field in the Niger Delta Using Eclipse Software

Ihekoronye Kingsley Kelechi^{1, *} , Milton Roy Zwalatha¹, Caleb Abdullahi Ibrahim¹, Mohammed Hussein²

¹Department of Petroleum Engineering, Abubakar Tafawa Balewa University (ATBU), Bauchi, Nigeria

²Department of Petroleum Engineering, Federal University of Technology, Owerri, Nigeria

Abstract

Surfactant-polymer flooding is a tertiary enhanced oil recovery method used to recover oil that remained in the reservoir after the primary and secondary oil recovery mechanisms. Predicting the pressure in the reservoir is important for oil production as pressure changes with time. A suitable approach to achieve this task is to derive fluid flow equation based on the reservoir characteristics and solve them numerically which provide the solution to the mathematical fluid flow model (diffusivity equation). In this study, 3-D reservoir was modelled using Eclipse software. The fluid flow equations in a porous media were derived based on the simulated model and the reservoir conditions. Numerical solution using implicit formulation to solve the mathematical fluid flow model (diffusivity equation) was investigated by developing Python codes using Jupyter library to ascertain the pressure distribution for the reservoir and imported into Eclipse simulator. Simulation was carried out using surfactant-polymer and reservoir properties to determine the oil recovery. The results of the study showed that pressure increases with time as oil production continued, and water saturation decreased for the grid-cells of the reservoir. Waterflooding had oil recovery of 38.0% and water-cut of 59.0%, while surfactant flooding had oil recoveries of 42.0%, 46.5%, 49.0% and water-cut of 57.0%, 51.0%, 46.3%. In addition, polymer flooding had oil recoveries of 44.3%, 48.4%, 54.0% and water-cut of 50.0%, 45.0% and 33.0% respectively at different concentrations of 0.3%wt. 0.4%wt. and 0.5%wt.

Keywords

Python Software, Eclipse Software, Modelling, Surfactant-Polymer Flooding

1. Introduction

The demand for energy is increasing and oil reserve is steadily declining. There is need to increase oil production using surfactant-polymer flooding to meet up the energy demand [4]. Tertiary recovery method is the application of surfactant and polymer into the reservoir when the secondary

technique had reached its economy limit (low oil recovery) [9]. Secondary oil recovery method can produce about 30% of the original oil in place [1]. The remaining oil left in the reservoir nearly 70% of the oil reserve can be recovered through the tertiary recovery methods especially as the global energy de-

*Corresponding author: kelechiking4@gmail.com (Ihekoronye Kingsley Kelechi)

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mand is growing rapidly [8]. Tertiary oil recovery is the application of chemicals in form of polymer and surfactant into the reservoir to recover additional oil that remained in the reservoir after primary and secondary recovery methods [2].

Reservoir simulation using Eclipse software helps to predict the production history of the reservoir in the future in order to evaluate its oil recovery efficiency and understand the flow behavior of fluids during surfactant-polymer flooding processes [6, 11]. Forecasting of oil production from the reservoir using Eclipse software is very important to evaluate the performance of the well in the future [10, 13]. Simulation using chemical flooding are often used in the industry to optimize, design, and interpret the mechanisms of surfactant-polymer flooding methods [5]. Eclipse reservoir simulation are used for surfactant-polymer flooding, history matching and field oil performance [12]. Therefore, the focus of this study is to model a 3-D reservoir, obtain the pressure distribution of the reservoir by implicit formulation and simulate flow for surfactant-polymer flooding using Eclipse software.

2. Mathematical Fluid Flow Model

4. Static Reservoir Model

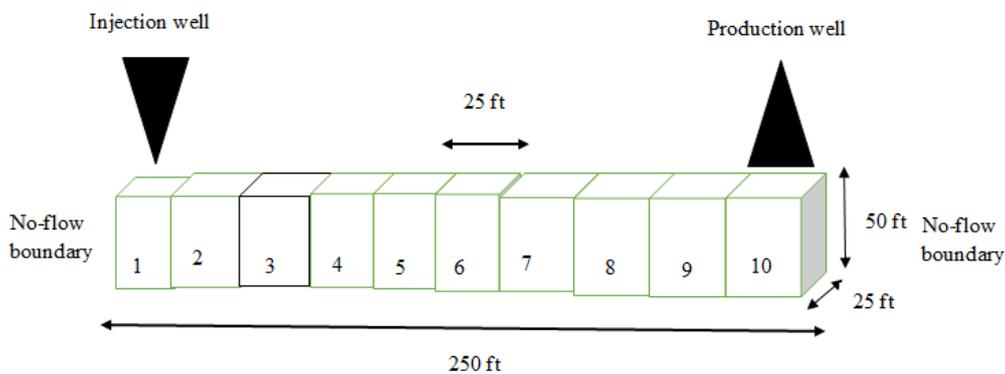


Figure 1. Reservoir Grid-blocks.

The development of a reservoir simulation begins with implicit/explicit formulation model (finite difference) for the mathematical fluid flow model (diffusivity equations) governing fluid flow in a porous media [3]. The diffusivity equation in form of partial differential equation describes the fluid flow in a porous medium and reservoir flow conditions [14]. Partial differential equation obeys the continuity equation, Darcy’s law and equation of state [7].

3. Research Methodology

- 1) Develop a static and dynamic reservoir model.
- 2) Derive a mathematical model (diffusivity equation) that describes the simulated model.
- 3) Solve the mathematical model (diffusivity equation) in a discretize form using a PYTHON codes (Jupyter library) to obtain the pressure distribution and water saturation of the reservoir.
- 4) Simulate flow with surfactant-polymer flooding.

Table 1. Reservoir Rock and Fluid Properties.

Reservoir properties	Values
Grid-block dimensions (x, y, z)	$\Delta x = 250$ ft, $\Delta y = 50$ ft, $\Delta z = 25$ ft
Oil viscosity (μ)	1.2 cP
Porosity (ϕ)	0.25
Permeability (K_x)	0.010 Darcy
Oil Formation Volume Factor, (B_o)	1.12 rb/stb
Total Compressibility, (C_t)	0.0000035 psi^{-1}
Initial Reservoir Pressure, (P_i)	3225 psia

4.1. Equation Governing Flow of Fluids in a Porous Media

The fluid flow in a porous media is governed by the continuity equation (material balance), transport equation (Darcy equation), and equation of state (slightly compressible fluids).

Continuity Equation (Material balance)

$$\frac{d}{dx}(g\rho) = \frac{dp}{dt} A \cdot \phi \text{ (accumulating system)} \quad (1)$$

Transport equation (Darcy law)

$$V = \frac{q}{A}$$

$$Q = VA \quad (2)$$

Putting equation 1 into equation 2

$$\frac{d}{dx}(V\rho)_A = A \cdot \phi \frac{dp}{dt}$$

$$\frac{d}{dx}(V\rho) = \phi \frac{dp}{dt} \quad (3)$$

Equation of state (slightly incompressible fluid)

$$Q = \frac{k}{u} \cdot \frac{dp}{dx} \quad (4)$$

Put equation 3 into 4

$$\frac{d}{dx} \left[\frac{k\rho}{\mu} \frac{dp}{dx} \right] = \phi \frac{dp}{dt} \quad (5)$$

$$\frac{d^2p}{dx^2} = \frac{u\phi c}{k} \cdot \frac{dp}{dt} \quad (6)$$

Equation 6 is called the diffusivity equation for linear system

Where p = pressure in (psi)

U = viscosity in (cp)

ϕ = porosity dimensionless

C = compressibility in (psi)

K = permeability in (mD)

4.2. Basic Assumptions Used

- 1) One dimensional flow
- 2) Uniform grid system
- 3) No-flow reservoir boundary condition
- 4) Homogeneous reservoir with block-centered grid cell

4.3. Finite Difference (Implicit Formulation)

Implicit Formulation

$$\frac{dp}{dt} = \frac{d^2p}{dx^2} \quad (7)$$

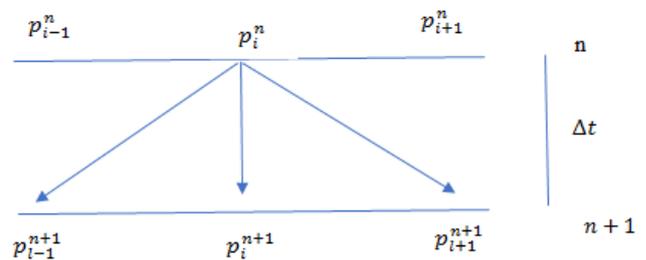


Figure 2. Implicit Formulation.

$$p_i^{n+1} - p_i^n = \frac{\Delta t}{\Delta x^2} [p_{i+1}^{n+1} + p_{i-1}^{n+1} - 2p_i^{n+1}] \quad (8)$$

$$-p_i^n = \frac{\Delta t}{\Delta x^2} p_{i+1}^{n+1} + \frac{\Delta t}{\Delta x^2} p_{i-1}^{n+1} - 2\left(\frac{\Delta t}{\Delta x^2}\right) p_i^{n+1} - p_i^{n+1} \quad (9)$$

$$\frac{\Delta x^2}{\Delta t} p_i^n = -p_{i+1}^{n+1} - p_{i-1}^{n+1} + 2 \cdot p_i^{n+1} + \frac{\Delta x}{\Delta t} p_i^{n+1} \quad (10)$$

$$\left(\frac{\Delta x^2}{\Delta t}\right) p_i^n = \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_i^{n+1} - p_{i+1}^{n+1} - p_{i-1}^{n+1} \quad (11)$$

$$p_{i-1}^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_i^{n+1} + p_{i+1}^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_i^n \quad (12)$$

For 10 grid blocks

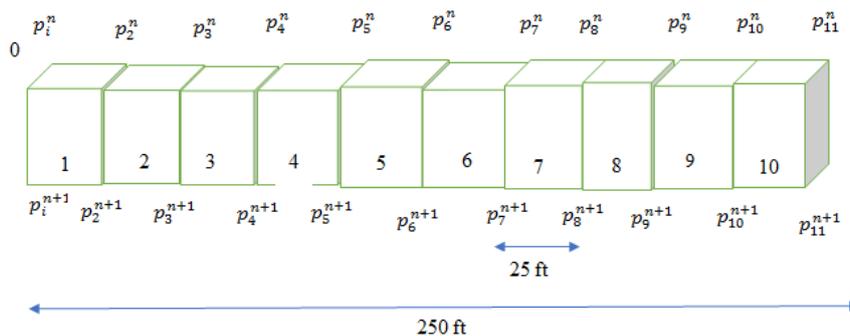


Figure 3. Reservoir Grid block.

$i = 1$ and $p_1 =$ fixed boundary = 3225 psi
 $i = 10$ and $p_{11} =$ fixed boundary = 2000 psi
 $i = 2$

$$p_1^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_2^{n+1} + p_3^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_2^n \quad (13)$$

$i = 3$

$$p_2^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_3^{n+1} + p_4^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_3^n \quad (14)$$

$i = 4$

$$p_3^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_4^{n+1} + p_5^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_4^n \quad (15)$$

$i = 5$

$$p_4^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_5^{n+1} + p_6^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_5^n \quad (16)$$

Therefore, for $i = 10$, we have
 $i = 10$

$$p_9^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_{10}^{n+1} + p_{11}^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_{10}^n \quad (17)$$

Since, $p_1^{n+1} = p_1 =$ fixed
 $p_{11}^{n+1} = p_{11} =$ fixed

$$-\left(2 + \frac{\Delta x^2}{\Delta t}\right) p_2^{n+1} + p_3^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_2^n - p_1 \quad (18)$$

$$p_9^{n+1} - \left(2 + \frac{\Delta x^2}{\Delta t}\right) p_{10}^{n+1} = -\left(\frac{\Delta x^2}{\Delta t}\right) p_{10}^n - p_{11}^n \quad (19)$$

$$\text{Set } -\left(2 + \frac{\Delta x^2}{\Delta t}\right) \quad (20)$$

$$\begin{bmatrix} a_{11} & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & a_{22} & 1 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 1 & a_{33} & 1 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 1 & a_{44} & 1 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 & a_{55} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 1 & a_{66} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 1 & a_{77} & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 1 & a_{88} & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 1 & a_{99} & 0 \end{bmatrix} \begin{bmatrix} p_2^{n+1} \\ p_3^{n+1} \\ p_4^{n+1} \\ p_5^{n+1} \\ p_6^{n+1} \\ p_7^{n+1} \\ p_8^{n+1} \\ p_9^{n+1} \end{bmatrix} = \begin{bmatrix} -\left(\frac{\Delta x^2}{\Delta t}\right) p_2^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_3^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_4^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_5^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_6^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_7^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_8^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_9^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_{10}^n \\ -\left(\frac{\Delta x^2}{\Delta t}\right) p_{11}^n \end{bmatrix} \quad (21)$$

Equation 21 in matrix form, was solved using Python codes (Jupyter library).

5. Dynamic Model

The reservoir was modelled using 3-dimensional method for a linear fluid flow system (figure 4). It contained three layers in X, Y, Z grids blocks which is $10 \times 1 \times 1$ cells. The dimensions of the grid blocks are 250 ft in X direction while Z was 25 ft and Y direction was 50 ft. Each grid block was 25 ft respectively. The injection well was placed at 1 and 2 grid-blocks at the water zones, while the production well was placed at 9 and 10 grid blocks saturated with oil. The properties of the reservoir such as porosity, permeability, depth, and net to gross thickness were designed to model the linear flow reservoir. The reservoir grids defined the geometry and

boundaries of the reservoir in the I, J and K directions. The aim of injecting the polymer is to increase the viscosity of water and control water mobility rate while the surfactant flooding changes the wettability of the rock from oil-wet to water-wet fluids to improve oil recovery. The simulation of oil production from the reservoir lasted for 11000 days. Waterflooding (secondary recovery method) was used as a base case to investigate the ultimate oil recovery before the introduction of surfactant and polymer as a tertiary oil recovery mechanism. Polymer and surfactant injection started at the first day of oil production. However, the surfactant used was formulated from *Thevetia Peruviana seed oil* via saponification reaction, while the polymer used was *Gum Arabic*. The properties of the characterized surfactant and polymer was inputted into the ECLIPSE software to evaluate the performance of the surfactant and polymer in enhanced oil recovery.

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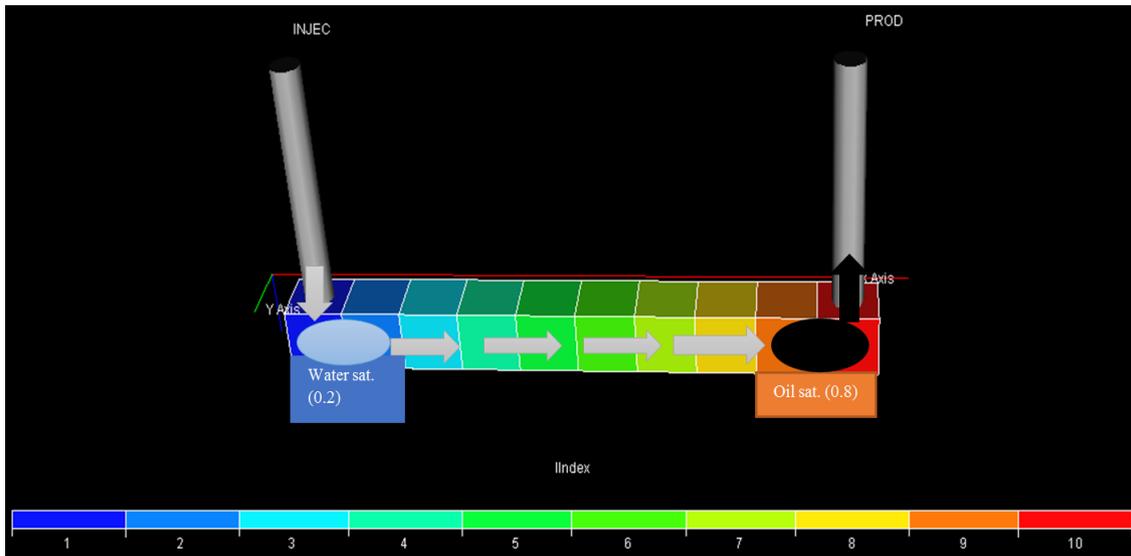


Figure 4. Reservoir Grid-blocks (3-D dynamic Model).

6. Results and Discussions

Results of the Implicit Formulation for Pressure Distribution and Water Saturation.

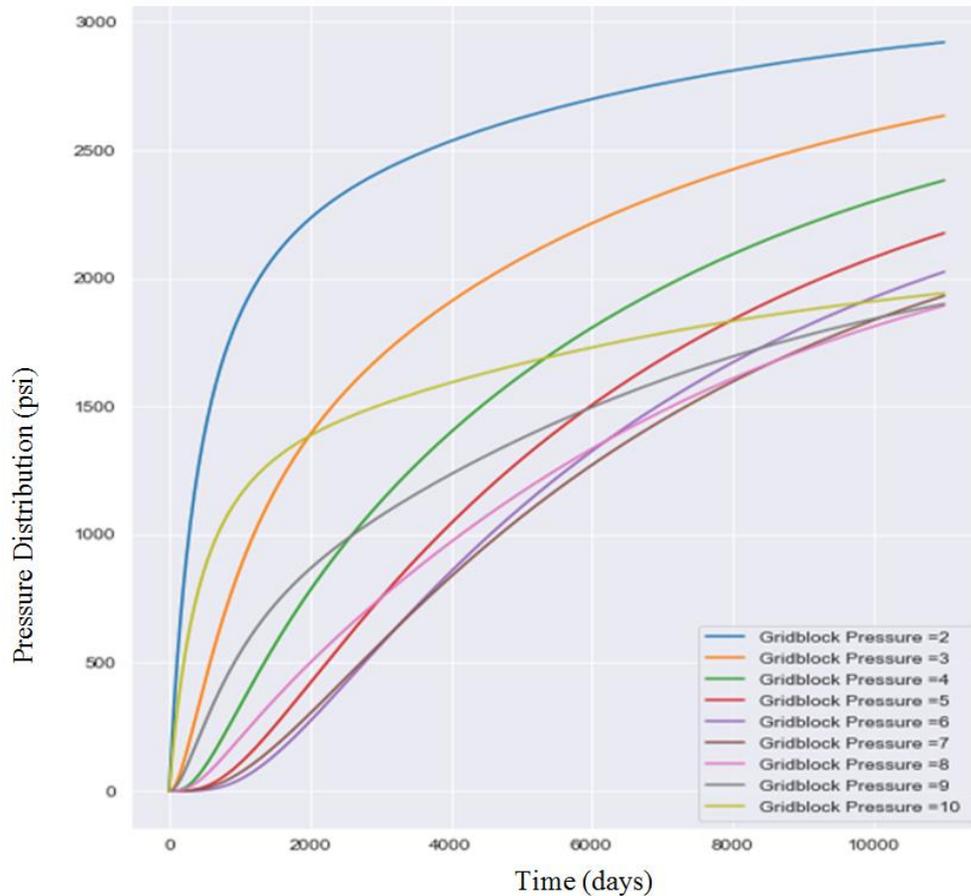


Figure 5. Pressure Distribution against time.

Figure 5 showed the pressure distribution of the reservoir (grid-blocks). Pressure increases with respect to time for each of the grid-blocks. Figure 6 showed the water saturation function of the grid blocks. The graph means that as the pressure in the reservoir increases as oil production continues, the water saturation decreases. The oil will fill the void space in the reservoir which was saturated with oil at each grid-blocks.

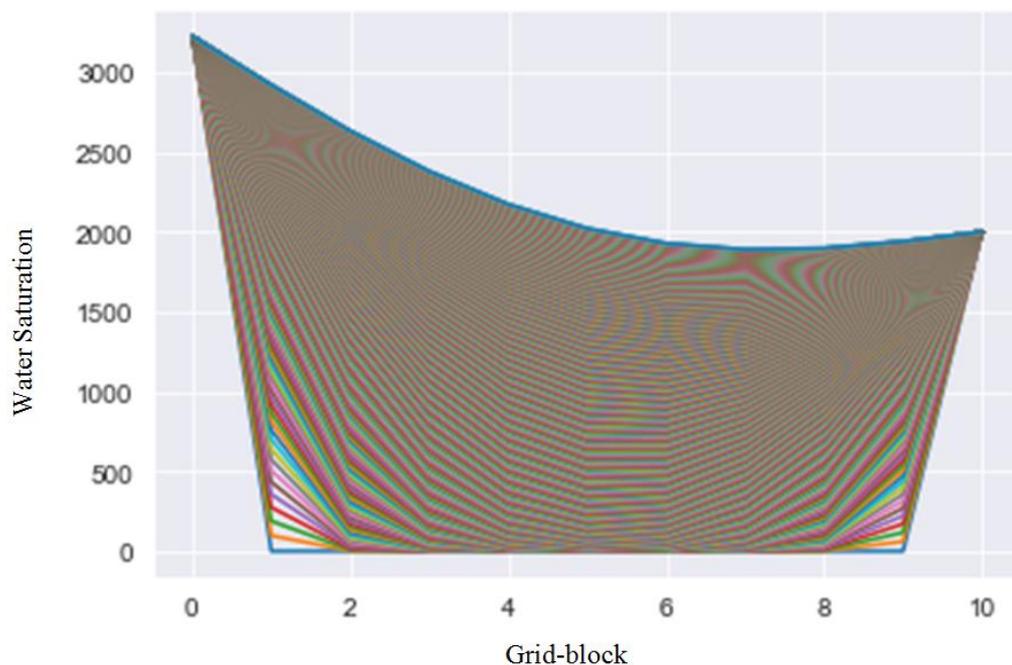


Figure 6. Water Saturation against Grid-block.

6.1. Results for Waterflooding

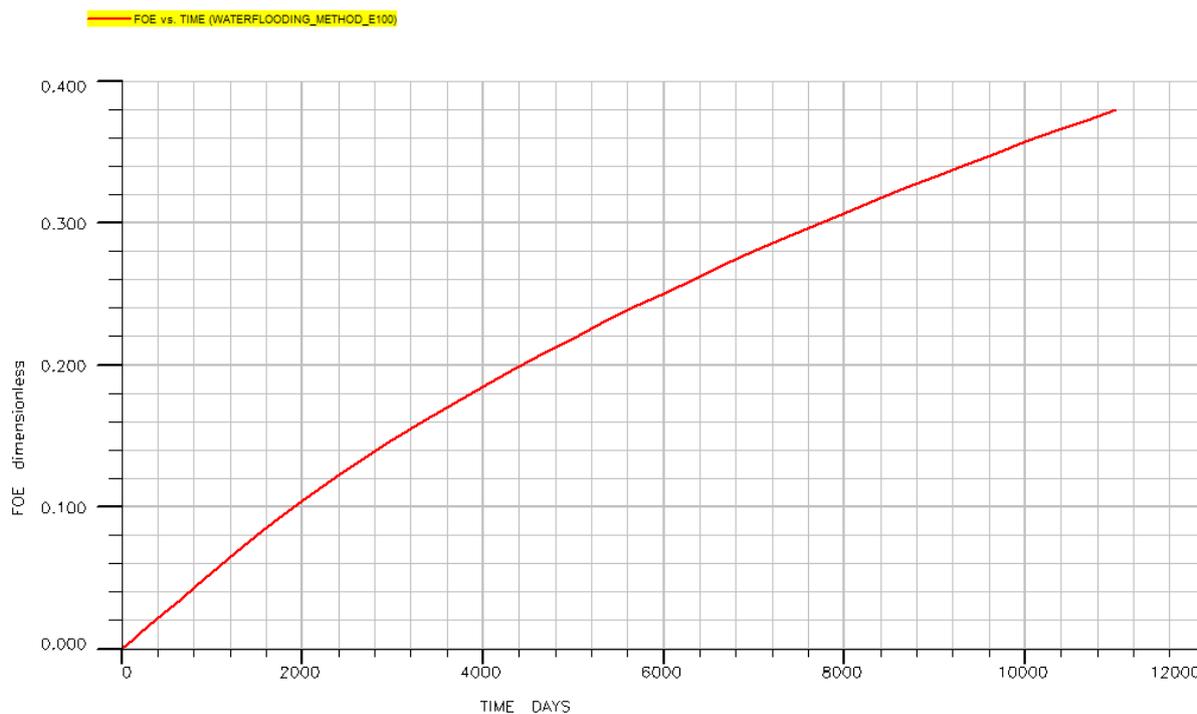


Figure 7. Field Oil Efficiency (oil recovery) against Time (days) for Waterflooding.

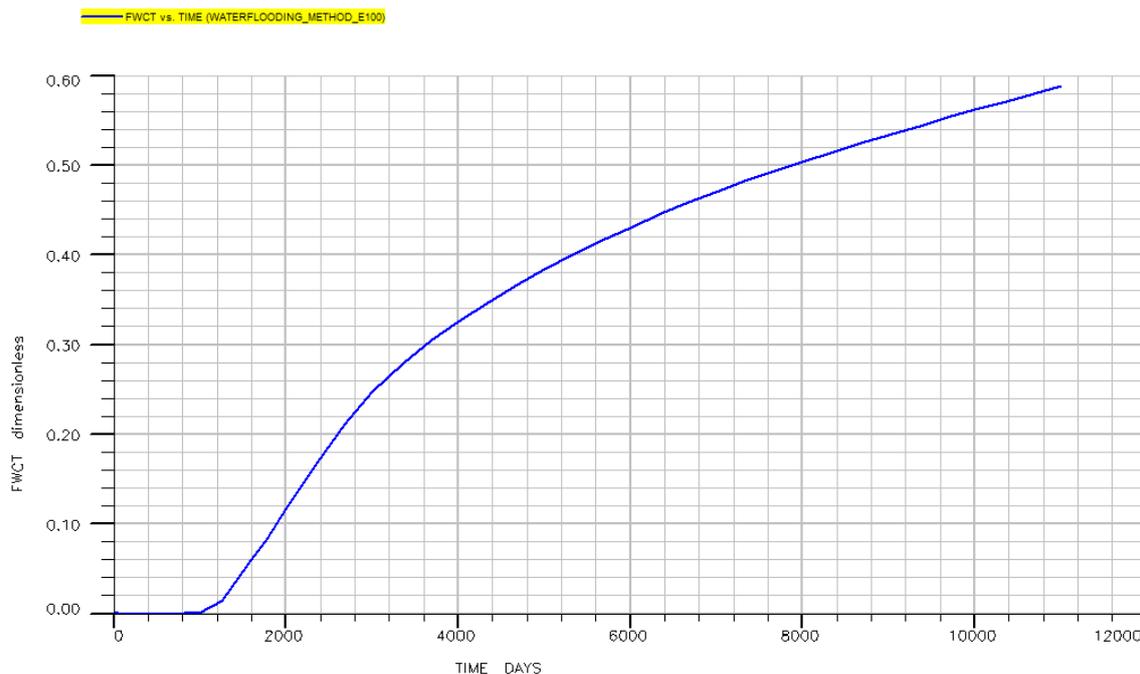


Figure 8. Field Water Cut (FWCT) against Time (days) for Waterflooding.

Figure 7 showed that the oil recovery was 38% when water was injected into the well to maintain reservoir pressure and enhance the reservoir sweep efficiency. The oil recovery result suggests that there is more oil that remained in the reservoir untapped since the saturated oil in this reservoir was 0.8 (80%). Therefore, tertiary recovery method using

polymer/surfactant can be introduced in this reservoir to recover more oil. Figure 8, showed that water was delayed to nine hundred days before the field began to experience early water breakthrough. The reservoir water cut was very high (59 %), which showed that there will be high production of water in a short time from the well.

6.2. Results for Surfactant Flooding

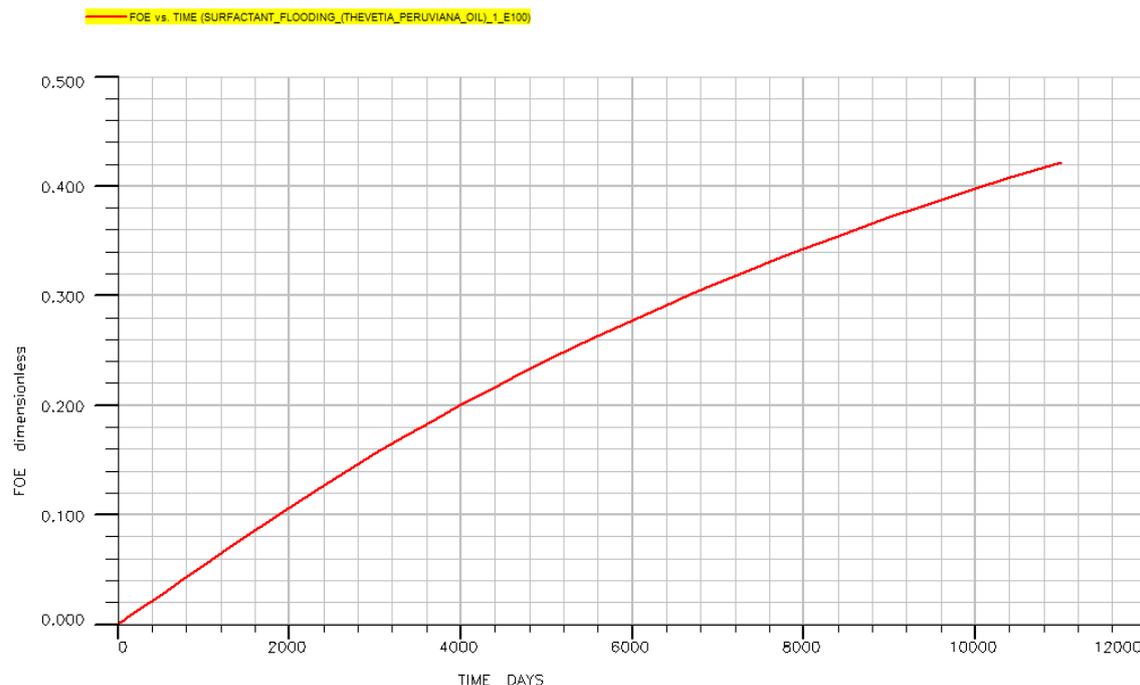


Figure 9. Field Oil Efficiency (oil recovery) against Time (days) for Surfactant Concentration (0.3%wt.).

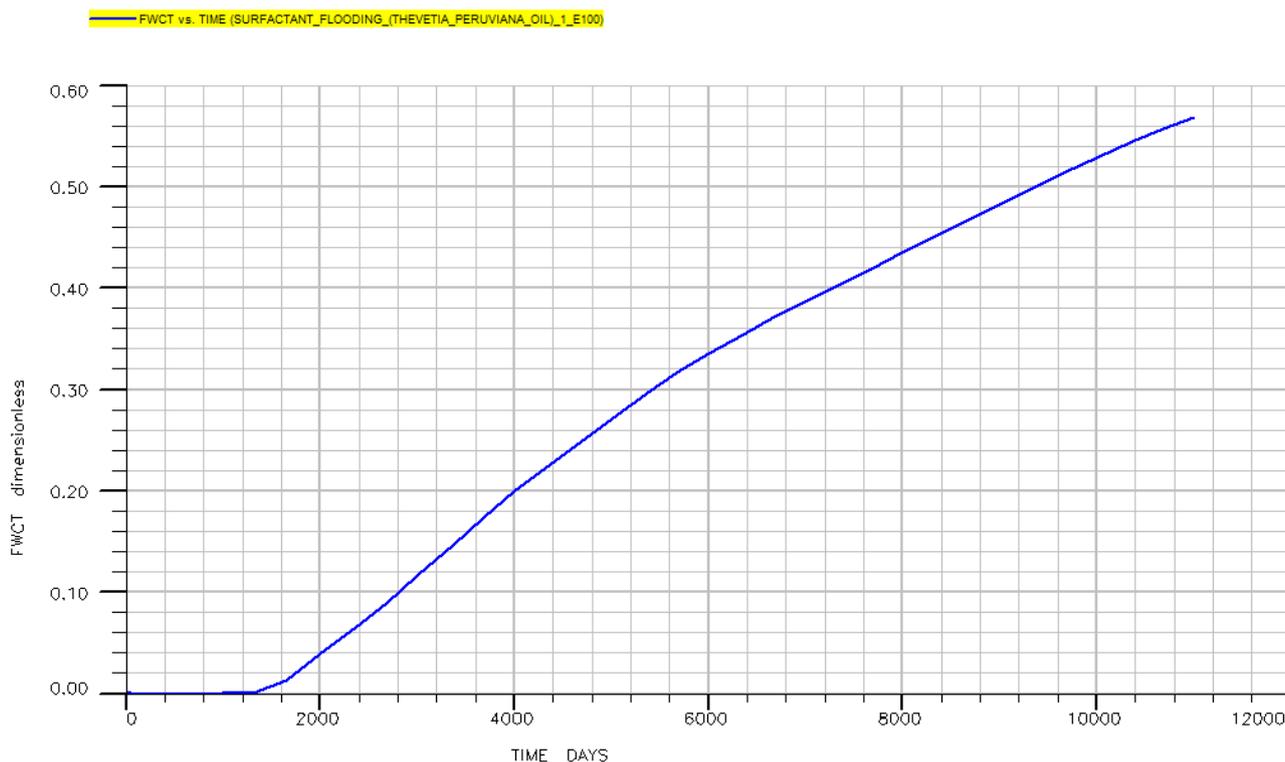


Figure 10. Field Water Cut (FWCT) against Time (days) for Surfactant Concentration (0.3%wt).

Surfactant flooding of 0.3% wt. gave oil recovery of 42% after eleven thousand days of oil production (figure 9). Increased in oil recovery using surfactant is due to the change in reservoir wettability from oil-wet to water-wet. The reservoir started producing water at one thousand, eight hundred days and field water cut was 57% (figure 10).

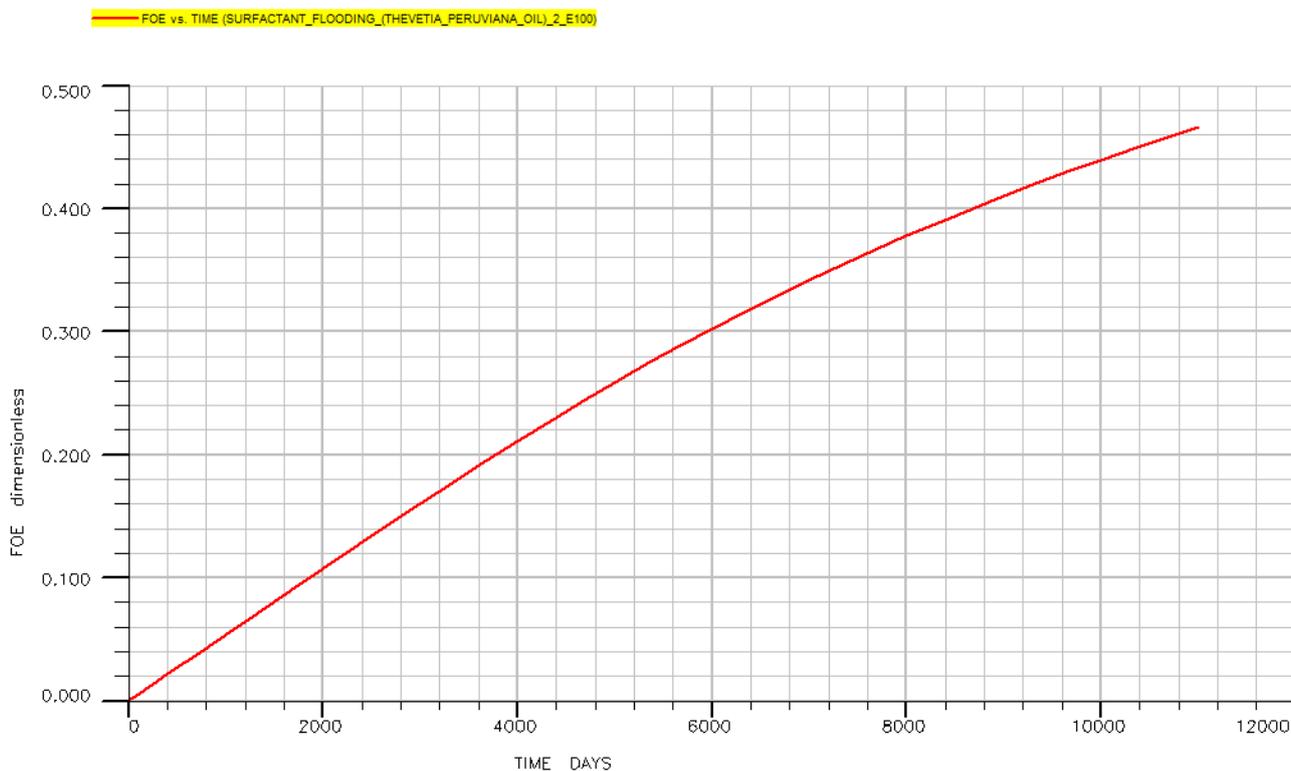


Figure 11. Field Oil Efficiency (oil recovery) against Time (days) for Surfactant Concentration (0.4%wt.).

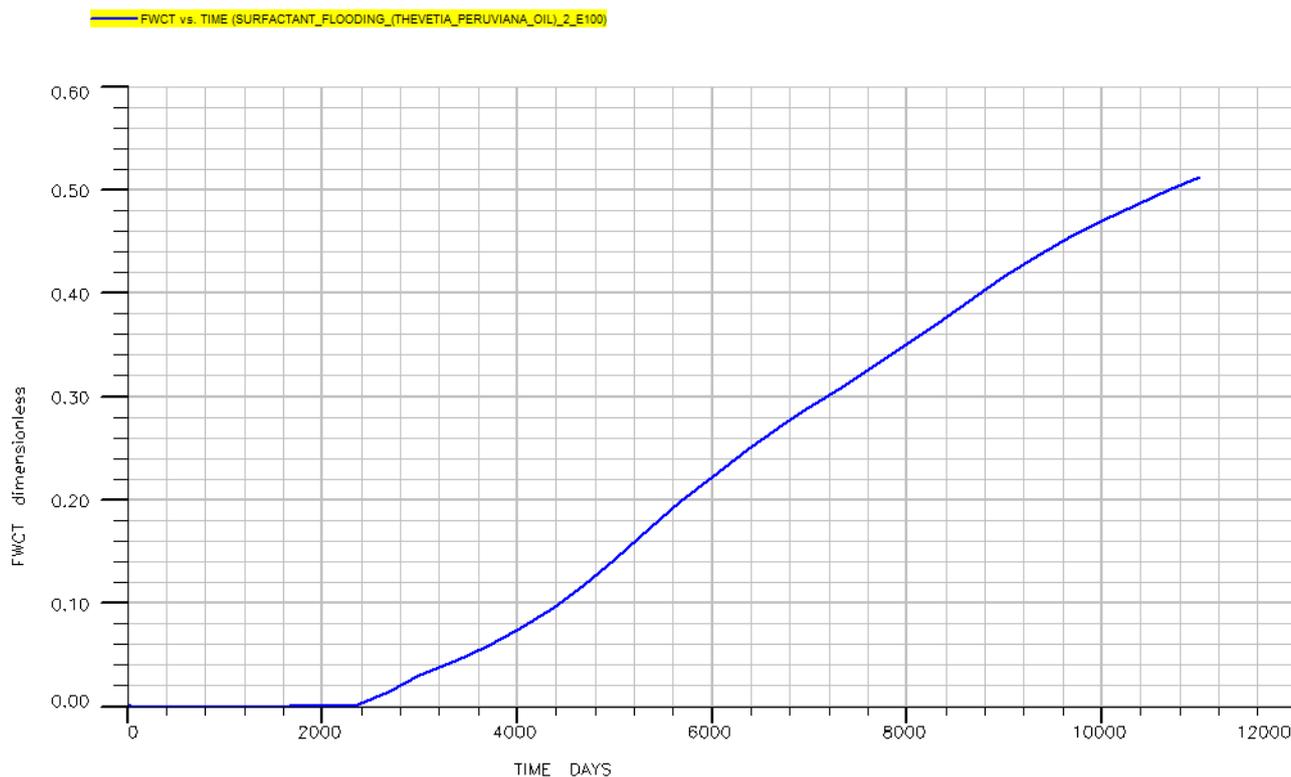


Figure 12. Field Water Cut (FWCT) against Time (days) for Surfactant Concentration (0.4%wt.).

Oil recovery increased further to 46% at surfactant concentration of 0.4% wt. (figure 11). More so, the reservoir started producing water in two thousand, three hundred days as field water cut was observed to be 51% (figure 12).

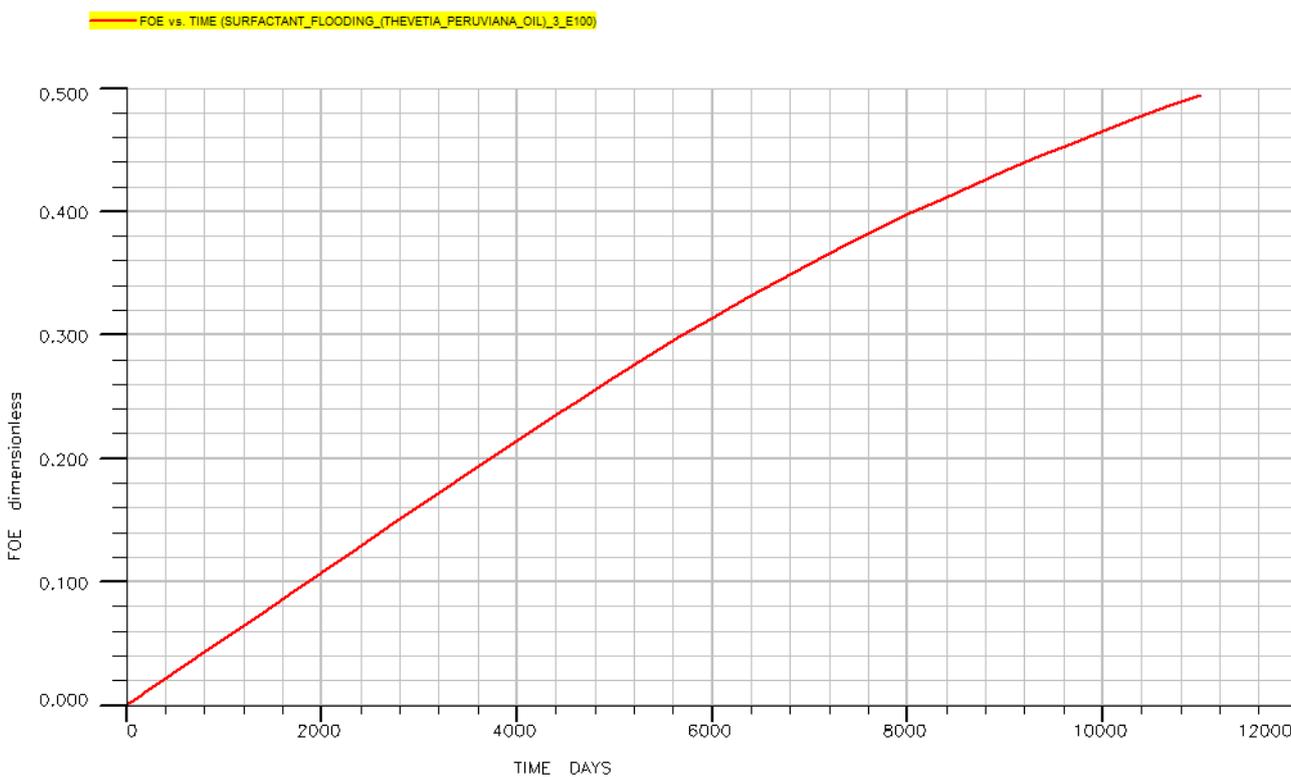


Figure 13. Field Oil Efficiency (oil recovery) against Time (days) for Surfactant Concentration (0.5%wt.).

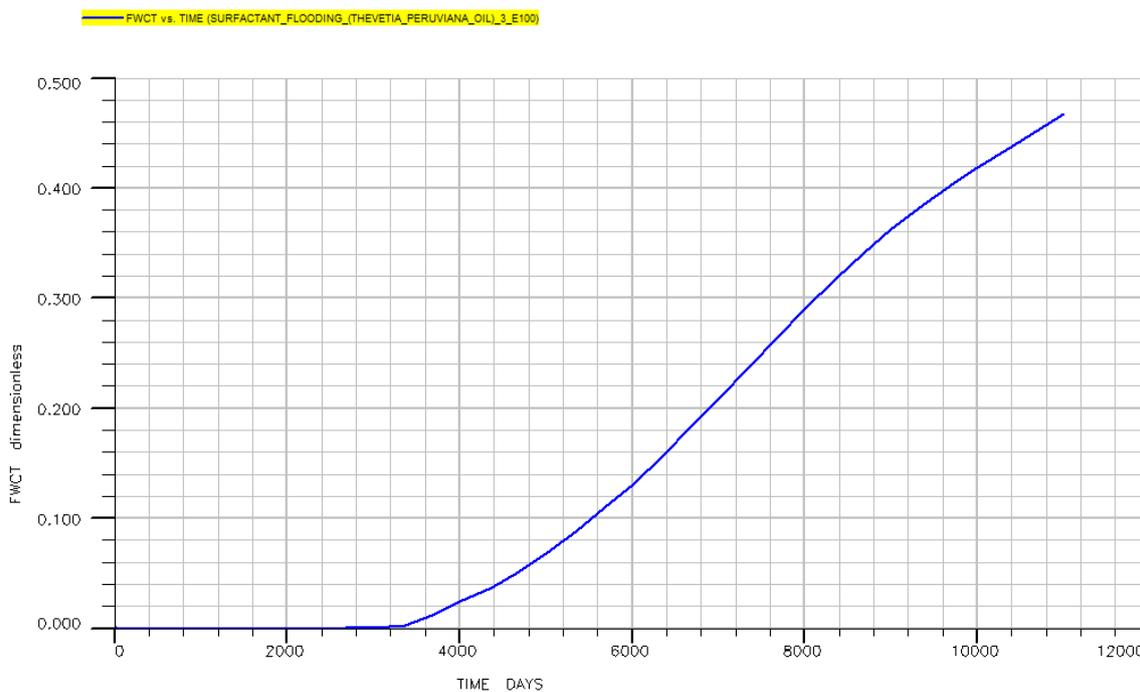


Figure 14. Field Water Cut (FWCT) against time (days) for Surfactant Concentration (0.5%wt.).

In figure 13, there was increase in oil recovery to 49% at surfactant concentration of 0.5%wt. The result means that concentration has a positive effect in surfactant flooding. It can be observed from the graph that this concentration gave the highest oil recovery when compared to 0.3% wt. and 0.4% wt. surfactant concentration respectively. Surfactant

flooding recovered 49% of the total oil in place 80%. Water-cut was 46.3% that is the percentage of water in the fluid produced from the well (figure 14). Water production started from three thousand seven hundred days, which suggest that water was delayed as oil was produced from the reservoir.

6.3. Results for Polymer Flooding

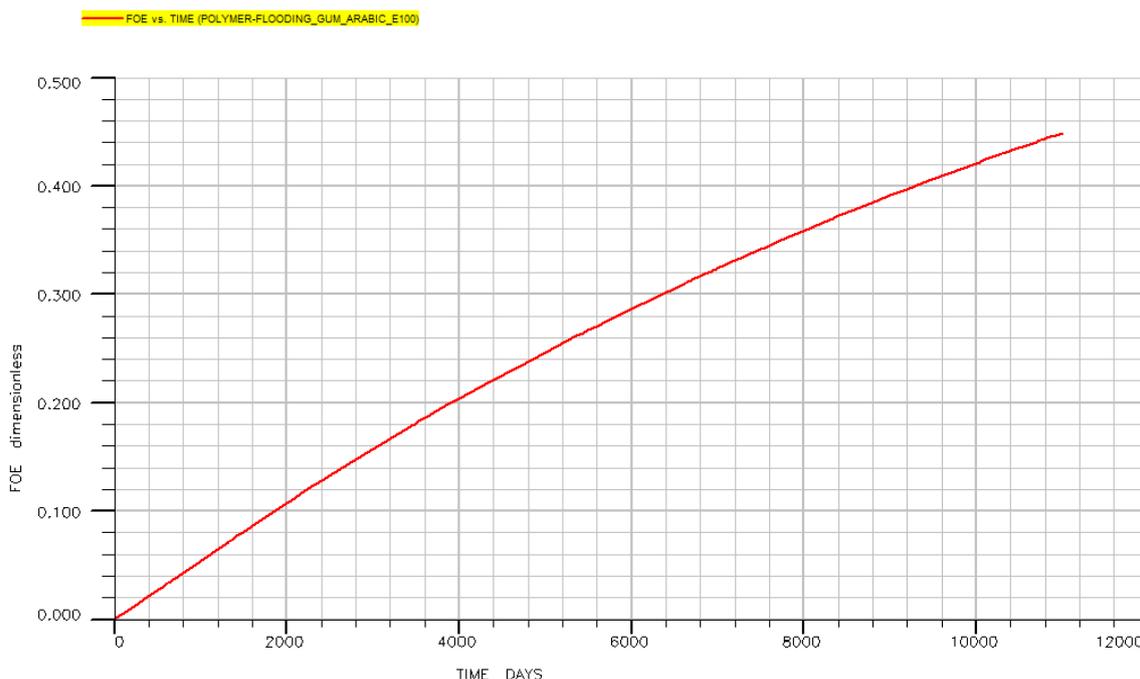


Figure 15. Field Oil Efficiency (oil recovery) against Time (days) for Polymer Concentration (0.3% wt.).

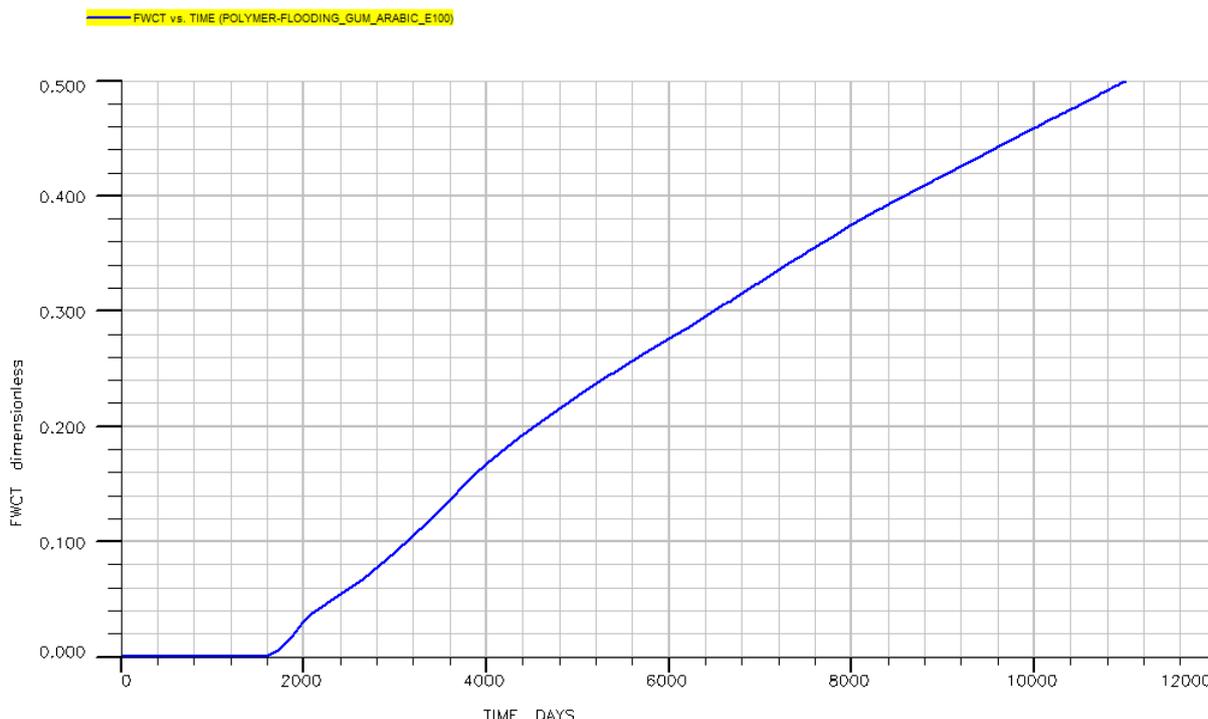


Figure 16. Field Water Cut (FWCT) against Time (days) for Polymer Concentration (0.3% wt.).

In figure 15, polymer concentration of 0.3wt% was injected which gave an oil recovery of 44.3%. The increase in oil recovery using polymer flooding is the fact that polymer increases the viscosity of the injected fluid (water) which helped to push the oil to the production well, hence, enhancing oil recovery. It is also important to note that, polymer

aided in reservoir sweep efficiency via mobility control of injected water. Figure 16 indicate that water production started in one thousand, eight hundred days which means that more oil was produced from this well before water breakthrough and field water cut was 50.0%.

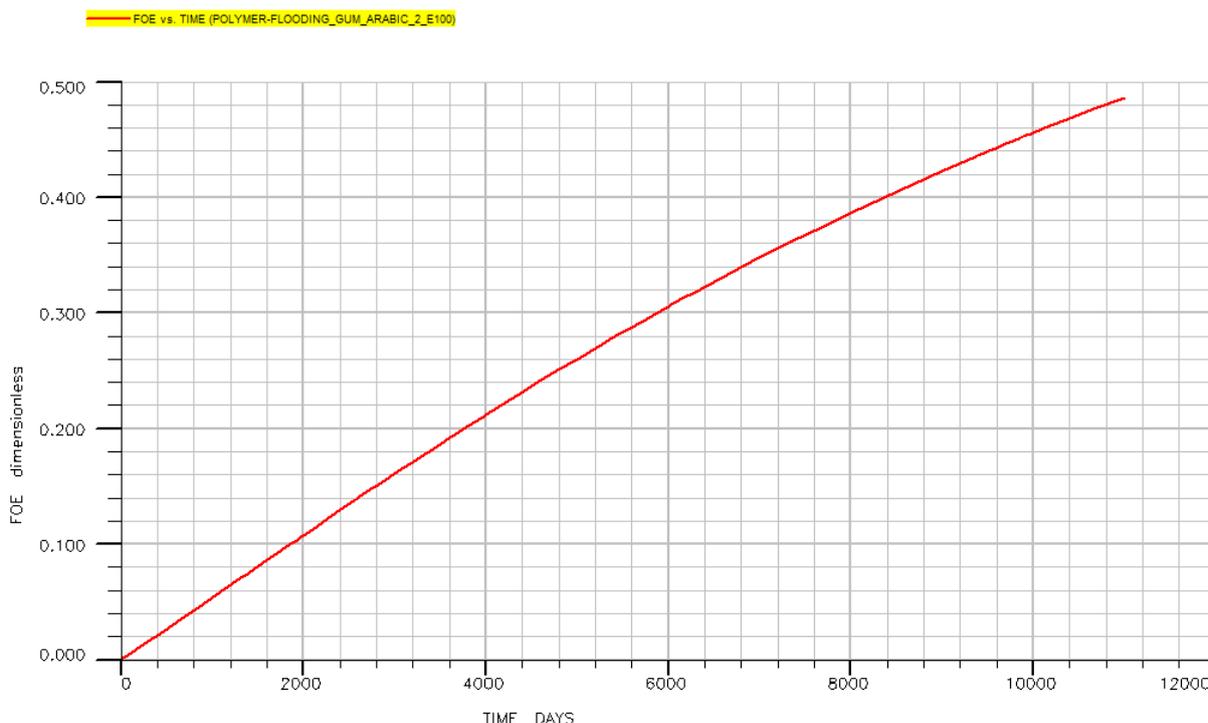


Figure 17. Field Oil Efficiency (oil recovery) against Time (days) for Polymer Concentration (0.4% wt.).

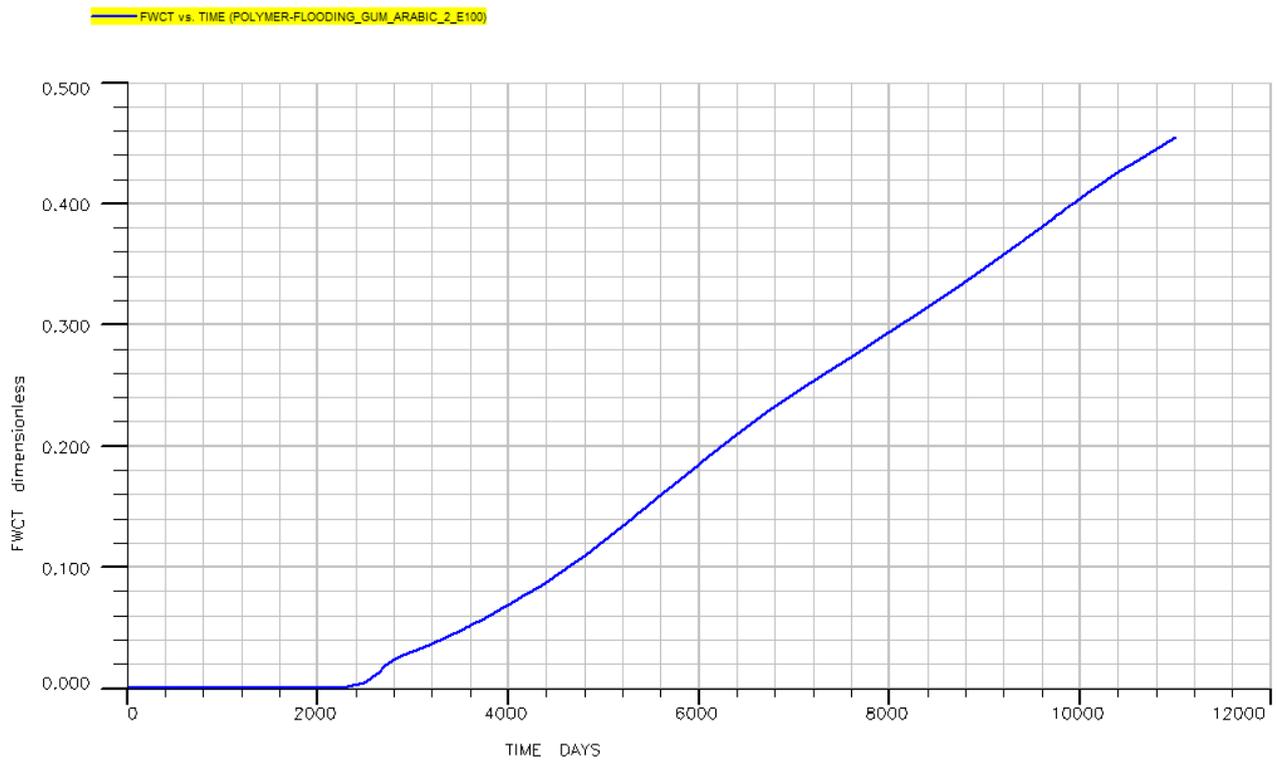


Figure 18. Field Water Cut (FWCT) against time (days) for Polymer Concentration (0.4% wt.).

Polymer flooding of 0.4wt% showed an increase in oil recovery of 48.4% (figure 17). The result suggest that concentration has a significant effect on oil recovery in polymer flooding. As more polymer was injected into the reservoir,

more oil was recovered. In addition, figure 18, showed water-cut of 45.0% and water breakthrough time started at two thousand, three hundred days of polymer injection.

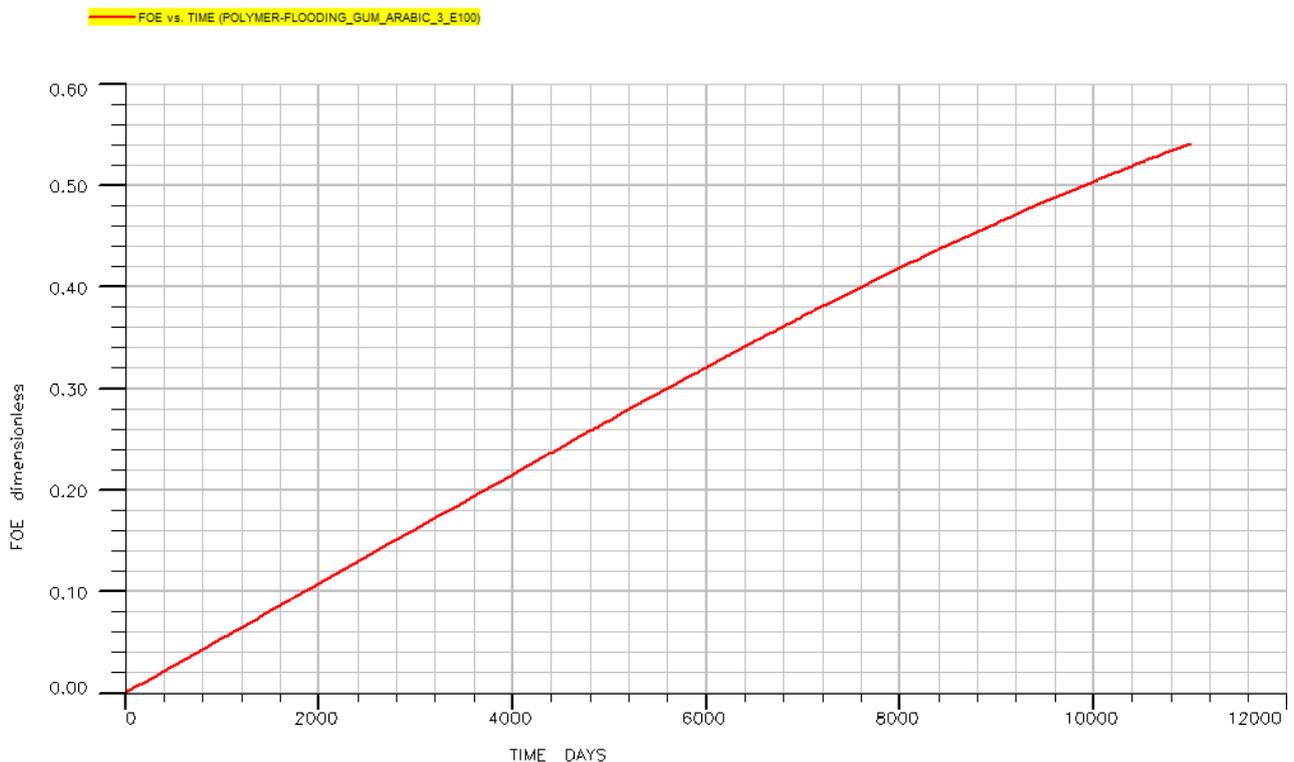


Figure 19. Field Oil Efficiency (oil recovery) against Time (days) for Polymer Concentration (0.5% wt.).

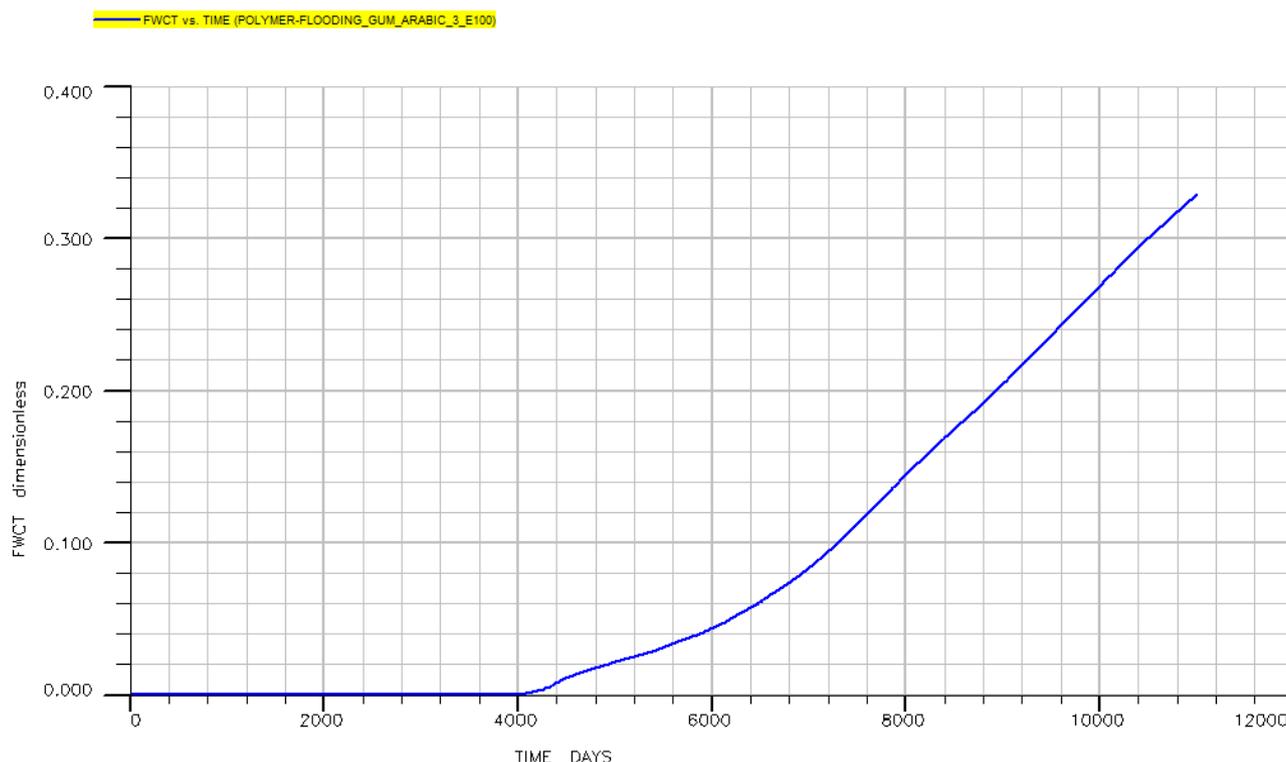


Figure 20. Field Water Cut (FWCT) against Time (days) for Polymer Concentration (0.5% wt.).

In figure 19, there was appreciably increase in oil recovery of 54.0% at polymer flooding of 0.5% wt. Increase in the concentration of polymer injection has a great effect in oil production. Polymer flooding had the highest oil recovery from the 80% oil in place in the reservoir. The results clearly suggest that polymer flooding have a greater sweep efficiency of oil when compared to water and surfactant flooding. Field water cut reduced to 33.0%. This means that oil was produced for four thousand days before water breakthrough as showed in figure 20. However, more surfactant and polymer at concentration of 0.6% wt. and 0.7% wt. was injected into the reservoir which oil recovery did not increase further. Hence, increase in oil recovery stopped at concentration of 0.5% wt.

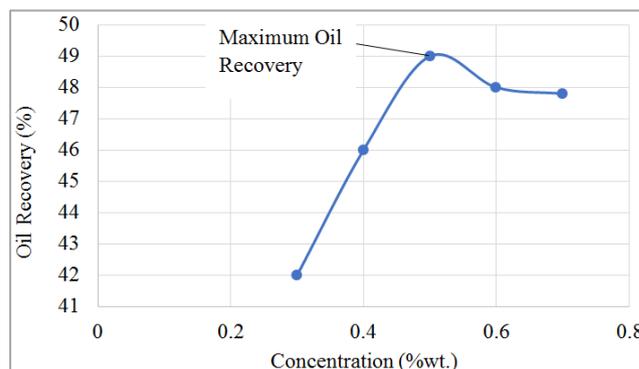


Figure 22. Oil Recovery against Surfactant Flooding Concentration.

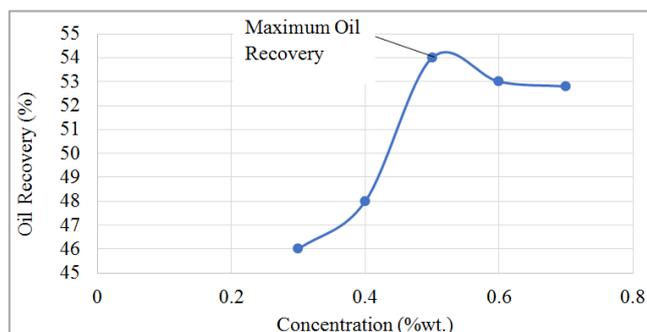


Figure 21. Oil Recovery against Polymer Flooding Concentration.

Figures 21 and 22 indicates the maximum oil recovery for the surfactant-polymer flooding. The graphs showed that oil recovery was highest at concentration of 0.5% wt. At the concentration of 0.6% wt. and 0.7% wt. of surfactant and polymer injection, oil recovery did not increase further.

7. Conclusions

The study modeled 3-D reservoir using Eclipse software. Diffusivity equation of the simulated reservoir was derived which governed the fluid flow in a porous media to obtain the pressure distribution of the reservoir. The diffusivity equation was solved using Python codes (Jupyter Library). Simulation was carried out using surfactant-polymer to eval-

uate its performance in enhanced oil recovery. The following conclusions was drawn from the simulation study;

- 1) The implicit formulation results showed that reservoir pressure increases with time as oil production continued and water saturation decreases for the reservoir grid blocks.
- 2) Waterflooding had oil recovery of 38.0%, surfactant flooding had oil recoveries of 42.0%, 46.0%, and 49.0% while polymer flooding had oil recoveries of 46.0%, 48.0% and 54.0% respectively.
- 3) Reservoir water-cut was very high during waterflooding (59.0%) which indicates early water breakthrough time. However, polymer flooding had low water-cut of (33.0%) at 0.5%wt. concentration and delayed water breakthrough time was observed at 4000 days.

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Conflicts of Interest

The authors declared no conflict of interest.

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