Petroleum and Coal

**Article** **Open Access**

# Optimal Recovery of Heavy-Oil Using Numerical Simulation of Polymer Flooding

*Mujeeb B. Adetayo*[1,4], Michael O. Onyekonwu[1,2], Oghenerume Ogolo[3]*

[1] *Petroleum Engineering Department, African University of Science and Technology, Abuja, Nigeria*
[2] *Petroleum Engineering Department, University of Port-Harcourt, Port-Harcourt, River State, Nigeria*
[3] *Petroleum and Gas Engineering Department, Nile University of Nigeria, Abuja, Nigeria*
[4] *Chemical Engineering Department, Marmara University, Istanbul, Turkey*

Received December 19, 2019; Accepted March 21, 2020

**Abstract**

These studies focused on polymer flooding for optimal recovery of heavy-oil. It was premised on a detailed reservoir simulation study using ECLIPSE and the polymer used was hydrolyzed polyacrylamide (HPAM). Water and polymer flooding cases were the scenarios considered. The water flooding case had its highest recovery with the "homogeneous case of low permeability" with a production total of 176412.3 $sm^3$ (FOE=50.1 %). As for the polymer flooding cases, polymer concentrations in the range of 1 to 5 $kg/m^3$ were tested. Polymer slugs with different concentrations at different injection times were injected for each case and the results were compared. The best polymer flooding case was with the use of HPAM of concentration 2.0 $kg/m^3$ with 7 years of polymer injection followed by chase water injection. It had a recovery efficiency of over 84%. It also shows the most favorable reservoir pattern for polymer flooding in the heavy oil reservoir.

***Keywords*** *Polymer flooding; Heavy oil; Simulation; ECLIPSE; Homogeneous; Heterogeneous; Recovery.*

## 1. Introduction

Reservoir development is increasingly moving towards the development of heavy oil and bitumen reservoirs [1]. It is highly possible that the future of the oil and gas industry also lies in heavy oil resources which are expected to play a key role in meeting energy demands in the future. Thus, having a proactive well-defined technically and economically feasible plan prior to the development of these unconventional resources and using the most efficient method is of paramount interest. Waterflooding of heavy oil reservoirs seems to possess certain challenges with the sweep efficiency due to the high mobility ratio encountered for heavy oil, but the injection of polymers may abate these challenges enabling better sweep efficiency of the flooding process [2-7].

The polymer flooding process is commonly referred to as the enhanced waterflooding process. This is because the polymer is added in water to lower the water-oil mobility ratio by increasing water viscosity [4-5,8-13]. The lowering of the water-oil mobility ratio results in the improvement of oil recovery. This is achieved by increasing areal, vertical, and displacement (or microscopic) sweep efficiencies [4,9]. This also reduces the detrimental effect of permeability variations and fractures and thereby improves both vertical and areal sweep efficiency [8,14-16]. Polymer flood response serves as a baseline by which the effectiveness of other polymer flooding related IOR processes can be measured. If the polymer technology can be successfully applied in the reservoirs of the study, then more complex chemical flood variations can be investigated, such as surfactant polymer flooding, alkali polymer flooding, and ASP.

This research work, therefore, was aimed at simulating polymer flooding operations in a heavy oil reservoir using a numerical approach so as to determine the best parameters for the optimum recovery of heavy oil. This was achieved through the use of ECLIPSE 100 reservoir simulator software.

## 2. Material and methods

### 2.1. Simulation model description

The research method was based on numerical simulation studies and follows that of [17] for light oil recovery. The polymer flooding was simulated using the Eclipse software, a commercial simulator developed by Schlumberger. The reservoir description, lithology, and conditions set to terminate the simulation run of the input file are shown in Table 1 and Table 2, while the reservoir views showing the grids are shown in Fig 1. The polymer used in this study was hydrolyzed polyacrylamide [5], and it is capable of withstanding temperature up to 210°C. This is far above the reservoir temperature and will not be easily degraded [17].

Table 1. Grid information

| Property | X (11 Grids) | Y (10 Grids) | Z (5 grids) | | | | |
|---|---|---|---|---|---|---|---|
| | | | Z1 | Z2 | Z3 | Z4 | Z5 |
| Grid dimension (m) | 25 | 30 | 4 | 3 | 3 | 3 | 3 |
| Porosity (%) | | | 35.9 | 35.9 | 35.9 | 35.9 | 35.9 |
| MULT Z | | | 0.64 | 0.66 | 0.66 | 0.66 | 0.66 |

Table 2. Reservoir rock and fluid properties

| Parameters | Range/Average value | Parameters | Range/average value |
|---|---|---|---|
| Field | RMT94 | Porosity (ϕ) | 35.90% |
| Depth | 1300-1450 m | Temperature (Tav) | 65°C |
| Oil viscosity | Surface condition: 305-673 cP Reservoir condition: 95.5 cP | WOC | 1378 m |
| Density | 0.9441 g/cm3 | Injector grid | 1 1 1 |
| API | 18.38 0API | Producer grid | 11 10 4 |
| Permeability | 2000-8000 md | Injection rate | 100 $m^3$/d |
| Fluids | Oil and Water | Qo (max) | 100 $m^3$/d |
| OOIP | 361,292.29 $m^3$ | BHP min (producer) | 170 psi |
| Pi | 195 bar | Well radius ($r_w$) | 0.076 m |
| Datum | 1360 m | Skin (S) | 0 |
| | | Simulation period | 10 years |

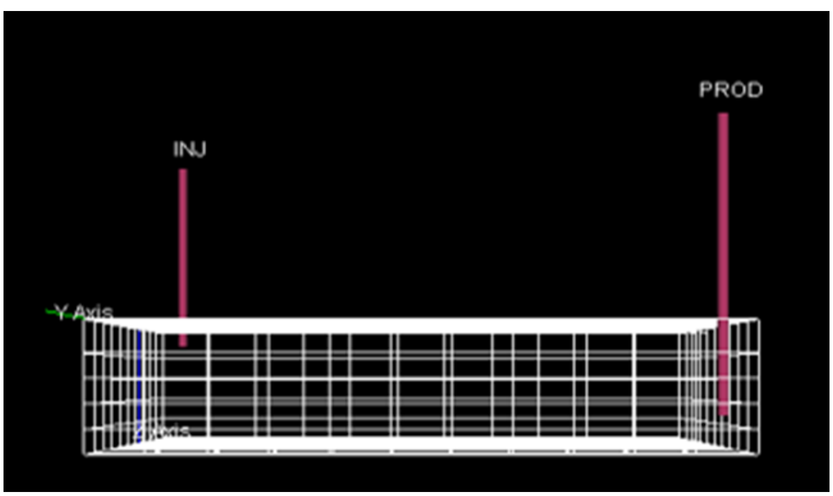


Figure 1. RMT94 Reservoir view showing the Grids and well locations

## 2.2. Field simulation

In this section, we investigate the effect of permeability which is a major parameter that influences the simulation process. The actual reservoir permeability lies between 2000 md and 8000 md. However, different permeability cases were considered in order to determine the effect of reservoir homogeneity and heterogeneity.

### *2.2.1. Homogeneous and heterogeneous cases*

Four different permeability variation cases were considered, which includes low and high permeability cases for both homogeneous and heterogeneous distribution. The four cases are shown in Table 3, with the heterogeneous cases viewed in the 3D model in Figure 2 and 3 [17].

Table 3. Homogeneous and heterogeneous cases with different layered permeability

| Homogeneous permeability cases k (mD) | | Z | DZ | Heterogeneous permeability cases k (mD) | |
|---|---|---|---|---|---|
| LOW | HIGH | Layers | (m) | LOW | HIGH |
| 400 | 1600 | Layer1 | 4 | 1280 | 1920 |
| 400 | 1600 | Layer2 | 3 | 1120 | 2080 |
| 400 | 1600 | Layer3 | 3 | 800 | 2400 |
| 400 | 1600 | Layer4 | 3 | 1280 | 1920 |
| 400 | 1600 | Layer5 | 3 | 1120 | 2080 |

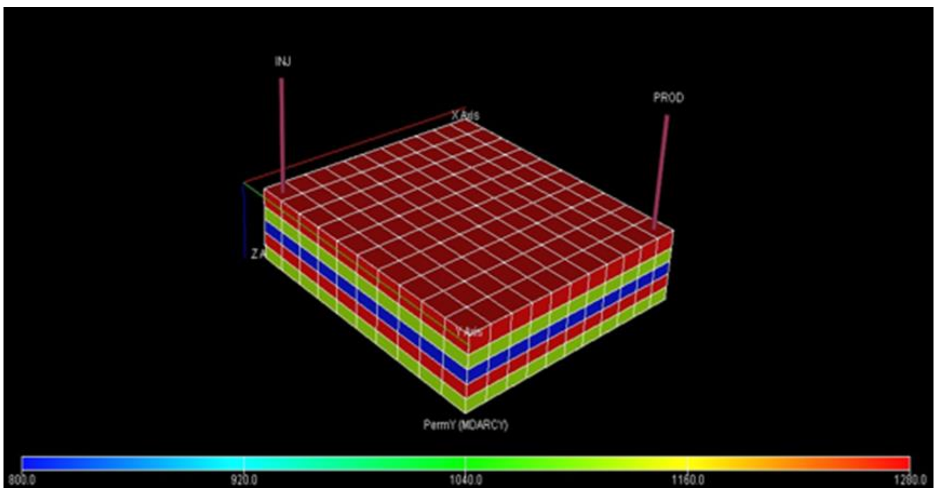


Figure 2. 3D model of the heterogeneous reservoir case of low permeability

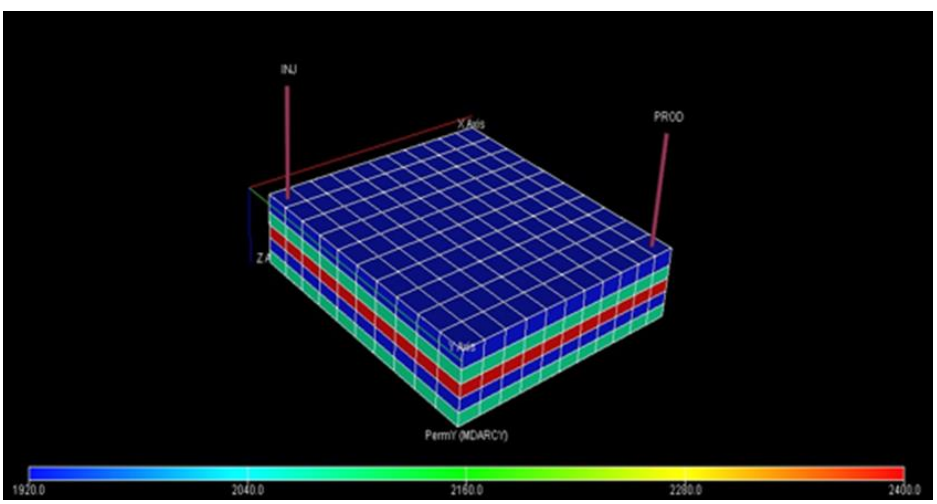


Figure 3. 3D model of the heterogeneous reservoir case of high permeability

#### *2.2.2. Polymer concentration determination*

The primary objective of this study is to identify the effective polymer concentration (under reservoir conditions) expected to yield optimum technical recovery factors and productivity from the heavy-oil deposits under consideration. Therefore, based on the permeability cases specified in Table 3, polymer concentration in the range of 1 to 5 kg/m$^3$ was tested on different injection patterns.

#### *2.2.3. Simulation cases considered*

The various simulations that were carried out are as follows:

#### *2.2.3.1. Water flooding (Base) cases:*

The simulations carried out followed the following patterns [17]:

- Water Flooding _ Homogeneous _ Low Permeability= WF_HOMO_LOW
- Water Flooding _ Homogeneous _ High Permeability= WF_HOMO_HIGH
- Water Flooding _ Heterogeneous_ Low Permeability= WF_HETERO_LOW
- Water Flooding _ Heterogeneous_ High Permeability= WF_HETERO_HIGH

#### *2.2.3.2. Polymer flooding cases:*

The simulations carried out followed the following patterns [17]:

- Polymer flooding _ Heterogeneous_ Low/High Permeability _ No of Years of Water Flooding_ No of Years of Polymer Flooding_ Polymer concentration.

For example, PF_HETERO_LOW_ 3_2_ 0.1 or simply: HETERO_LOW_ 3_2_ 0.1.

So as to get the overall best polymer injection case, different stages of polymer injection were carried out for 10 years simulation period. The three major injection profiles considered were:

a. Initial Polymer Flooding: This was to determine optimum polymer concentration:
- 1 year polymer flooding + 9 years water flooding
- 2 years polymer flooding + 8 years water flooding
- 3 years polymer flooding + 7 years water flooding

b. Initial Water Flooding Followed by Polymer Flooding
- 1 year water flooding + 3 years polymer flooding + 6 years chase water injection
- 2 years water flooding + 3 years polymer flooding + 5 years chase water injection
- 3 years water flooding + 3 years polymer flooding + 4 years chase water injection

c. Polymer Flooding Year Extension: This is the extension of the number of years of the polymer flooding for the best cases in injection profiles A and B to determine the overall best polymer flooding pattern.

Processes in injection profile A are of initial polymer flooding, which was carried out on all 4 permeability cases with different years 1, 2, and 3 of initial polymer injection. Processes in injection profile b were carried out on the best case in injection profile A. Finally; injection profile C was carried out on the best case from injection profile A and B to get the overall best polymer flooding case.

## 3. Results and discussion

### 3.1. Waterflooding simulation

Based on the permeability cases specified in Table 3 above, Figures 4 and 5 shows that the highest oil recovery obtained was 50.1 % (homogeneous case of low permeability: WF_HOMO_LOW). This was followed by 48.6 % (heterogeneous case of low permeability: WF_HETERO_LOW), 46.2% (homogeneous case of high permeability: WF_HOMO_HIGH) and finally 44.8% (heterogeneous case of high permeability: WF_HETERO_HIGH). This is summarized in Figure 6.

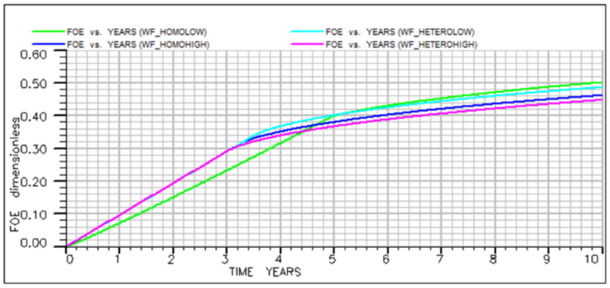


Figure 4. Field oil efficiency (FOE) for all water flooding cases

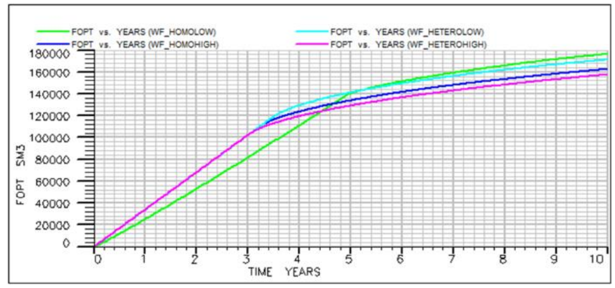


Figure 5. Field oil production total (FOPT) for all water flooding cases

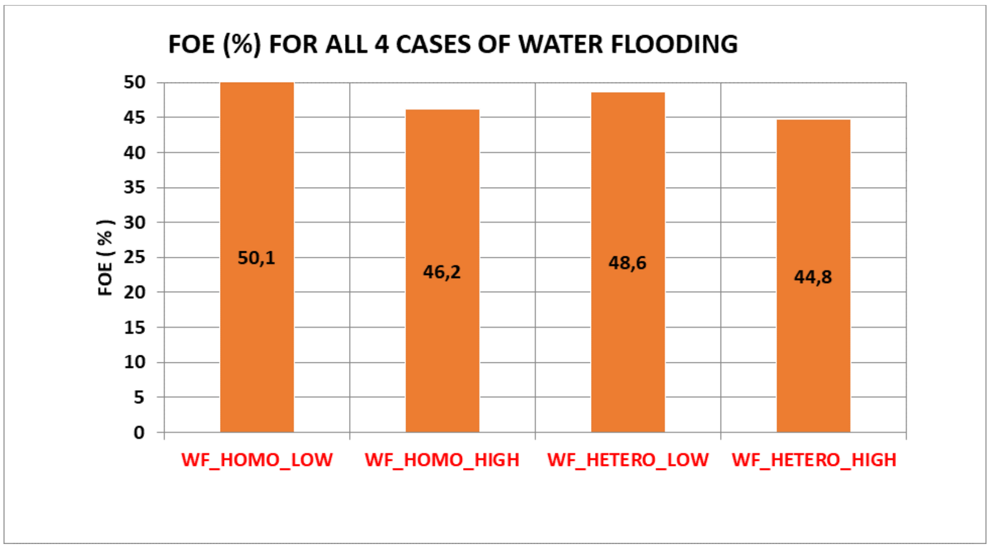


Figure 6. Field oil efficiency (FOE) for water flooding cases

With the low permeability reservoirs giving better recovery than high permeability ones, it shows that the water flooding process is sensitive to reservoir permeability. This is because in low permeability reservoirs, there is more resistance to the flow of the displacement fluid (water). The mobility of water is reduced, causing less fingering effect and late water breakthrough. However, the displacement fluid (water) tends to move very fast in high permeability reservoirs causing severe fingering and reducing the rate of recovery.

Figure 5 shows that the Field Oil Production Total (FOPT) is analogous to the Field Oil Efficiency (FOE). It therefore gives a similar trend with the FOE with the homogeneous case of low permeability having the highest production total of 176412.3 sm$^3$, followed the heterogeneous case of low permeability with a total production of about 171224.19 sm$^3$ and the heterogeneous case of high permeability had the least total production of 157651.47 sm$^3$ as seen in Figure 7.

The water breakthrough time can be determined from Figures 8 and 9 which shows the field water cut and field pressure respectively for all the water flooding cases. The homogeneous case of low permeability gave the best case with a breakthrough occurring in the fifth year compared with the others of less than 3.5 years of water breakthrough. This is because low permeability impedes water mobility and thereby delaying water breakthrough. This is also evident in Figures 9 and 10 where the homogeneous case of low permeability had the most stabilized field pressure and field production rate.

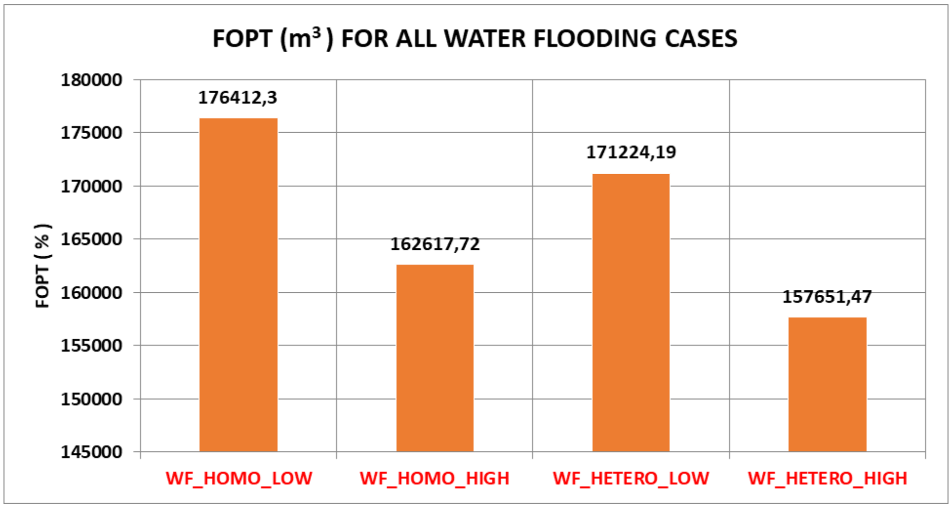


Figure 7. Field oil production total (FOPT) for all water flooding cases

The trend observed in the field water cut result was the reverse of that of the field oil production rate. This is because production causes the reduction of the reservoir pressure, and water injection tends to maintain this pressure from declining. However, at breakthrough, the pressure decline sharply, and the production rate drops. This is evident in Figures 8, 9 and 10. It is seen that the pressure and production rate starts to decline at the same year when the water cut begins to rise.

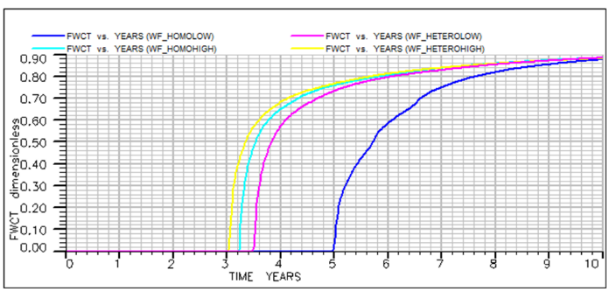


Figure 8. Field water cut (FWCT) for all 4 water flooding cases

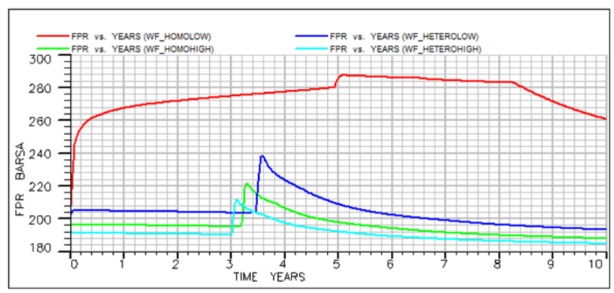


Figure 9. Field pressure (FPR) for all water flooding cases

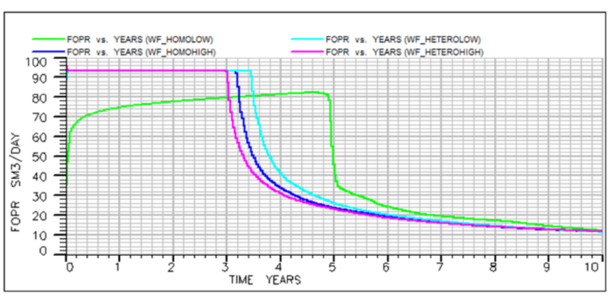


Figure 10. Field oil production rate (FOPR) for all water flooding cases

## 3.2. Polymer flooding simulations

### *3.2.1. Initial polymer flooding*

This was carried out to determine optimum polymer concentration. Based on the permeability cases specified in Table 3, polymer concentration in the range of 1 to 5 kg/m$^3$ were tested on three different injection patterns shown below:

- 1 year polymer flooding + 9 years water flooding
- 2 years polymer flooding + 8 years water flooding
- 3 years polymer flooding + 7 years water flooding.

Table A1 under the Appendix shows the various polymer concentrations and their corresponding field efficiencies. HETERO_HIGH_0_3_2.0, as shown in Figure 11 gave the highest Field Oil Efficiency of 77%. With the best results obtained from the heterogeneous and high permeable reservoirs, it implies that polymer flooding processes tend to be more sensitive to high reservoir heterogeneity and therefore gives better recovery in heterogeneous reservoirs of high permeability. This is because high permeability favors polymer flooding due to the mobility ratio, which has been highly reduced by the viscous nature of the polymer solution. Additionally, there is fewer polymer retention or adsorption in high permeability cases causing less reduction of slag viscosity and hence better sweep.

This result is similar to that of [17] except that the optimum polymer flooding years used was limited to just 1 year. This is, however, understandable for light oil of very low viscosity which was used in the studies.

Moreover, with all the highest recoveries gotten from the 3 years injection pattern as shown in Table A1 (HETERO_HIGH_0_3_2.0: 77%, HOMO_HIGH_0_3_2.0, and HETERO_HIGH_0_3_5.0: 75.5%, HETERO_HIGH_0_3_3.0: 73.8% and HETERO_HIGH_0_3_1.0: 72.82%), it implies that the recovery is proportional to the number of polymer injection years. Therefore, the number of injection years can still be extended beyond 3 years till the optimum is determined as will be seen shortly.

Finally, the polymer concentration which gave the highest recovery for all five cases considered was 2.0 kg/m$^3$. The use of a concentration higher or lower than this gave a lower efficiency and recovery, as seen in Table A1. This implies that there is an optimum polymer concentration that gives optimum recovery from a polymer injection process. Therefore, the optimum polymer concentration for the case considered in this work can be set as 2 kg/m$^3$.

### *3.2.2. Initial water flooding followed by polymer flooding*

The second polymer injection scenario was carried out on all best cases from the first polymer injection scenario as discussed in the previous section. At this stage, water flooding was carried out first, then followed by polymer flooding before the injection of chase water. The injection patterns used were:

- 1 year water flooding + 3 years polymer flooding + 6 years chase water injection
- 2 years water flooding + 3 years polymer flooding + 5 years chase water injection
- 3 years water flooding + 3 years polymer flooding + 4 years chase water injection

The aim here was to compare these 3 patterns (HETERO_HIGH_1_3_2.0, HETERO_HIGH_2_3_2.0, and HETERO_HIGH_3_3_2.0) with the best case in section 3.2.1 above which is wholly polymer injection. The initial polymer flooding (HETERO_HIGH_0_3_2.0) gave the best FOE of 77%, followed by HETERO_HIGH_1_3_2.0. This is because considering the technical aspect of an initial water flood before polymer injection, the polymer when introduced, will have to displace the already injected water leading to an early water breakthrough. This is evident from the simulation results in Figure 11 with the 3 years initial water flooding (HETERO_HIGH_3_3_2.0) giving the lowest recovery with an early water breakthrough of about 3 years, followed by HETERO_HIGH_2_3_2.0 with 2 years initial water flooding and HETERO_HIGH_1_3_2.0 with just 1 year of initial water flooding.

The best recovery is therefore obtained from HETERO_HIGH_0_3_2.0 where the polymer flooding is not preceded by an initial water flooding process. The water breakthrough is delayed for about 7.5 years as shown in Figure 12. This implies that a delay in the polymer injection causes a decline in the overall recovery.

Furthermore, the trend observed in the Field Water Cut result (FWCT) shown in Figure 12 is the reverse of that of the Field Oil Production Rate (FOPR) in Figure 13. This is because production causes the reservoir pressure to reduce, and water injection tends to maintain this pressure from decline. However, at breakthrough, the pressure decline sharply and the production rate drops. This is evident in Figure 12 when viewed along with Figures 13 and 14. It is seen that the pressure in Figure 14 and the production rate in Figure 13 starts to decline at the same year when the water cut begins to rise.

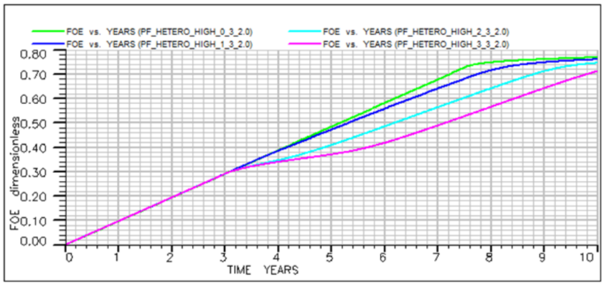


Figure 11. Field oil efficiency for (i) 3 years initial polymer flooding, (ii) 1 year initial water flooding followed by polymer flooding, (iii) 2 years initial water flooding followed by polymer flooding and (iv) 3 years initial water flooding followed by polymer flooding (2kg/m$^3$)

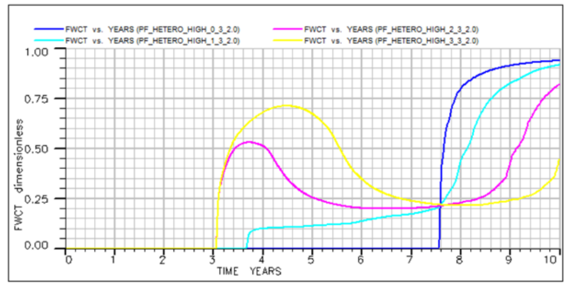


Figure 12. Field water cut for (i) 3 years initial polymer flooding, (ii) 1 year initial water flooding followed by polymer flooding, (iii) 2 years initial water flooding followed by polymer flooding and (iv) 3 years initial water flooding followed by polymer flooding (2kg/m$^3$)

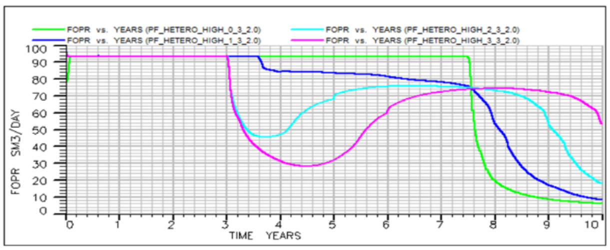


Figure 13. Field oil production rate for (i) 3 years initial polymer flooding, (ii) 1 year initial water flooding followed by polymer flooding, (iii) 2 years initial water flooding followed by polymer flooding and (iv) 3 years initial water flooding followed by polymer flooding (2kg/m$^3$)

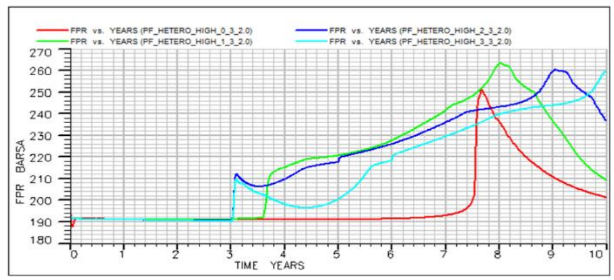


Figure 14. Field pressure for (i) 3 years initial polymer flooding, (ii) 1 year initial water flooding followed by polymer flooding, (iii) 2 years initial water flooding followed by polymer flooding and (iv) 3 years initial water flooding followed by polymer flooding (2kg/m$^3$)

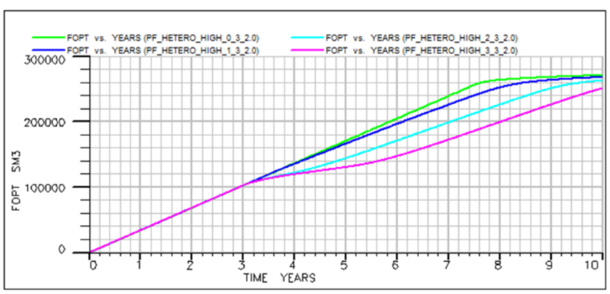


Figure 15. Field oil production total for (i) 3 years initial polymer flooding, (ii) 1 year initial water flooding followed by polymer flooding, (iii) 2 years initial water flooding followed by polymer flooding and (iv) 3 years initial water flooding followed by polymer flooding (2kg/m$^3$)

#### *3.2.3. Extension of the number of years of polymer flooding to determine the optimum flooding years*

The third polymer injection scenario was carried out on the best case of the second polymer injection scenario (HETERO_HIGH_0_3_2.0). The aim here was to determine the optimum polymer injection years by increasing the years of polymer injection and to determine the overall best polymer flooding case. The injection patterns used were:

- 3 years polymer flooding + 7 years chase water injection (HETERO_HIGH_0_3_2.0)
- 4 years polymer flooding + 6 years chase water injection (HETERO_HIGH_0_4_2.0)
- 5 years polymer flooding + 5 years chase water injection (HETERO_HIGH_0_5_2.0)
- 6 years polymer flooding + 4 years chase water injection (HETERO_HIGH_0_6_2.0)
- 7 years polymer flooding + 3 years chase water injection (HETERO_HIGH_0_7_2.0)
- 8 years polymer flooding + 2 years chase water injection (HETERO_HIGH_0_8_2.0)

The overall best case, according to Figures 16 and 17 was 7 years of polymer injection in a heterogeneous reservoir of high permeability (HETERO_HIGH_0_7_2.0) with 83.05% Field

Oil Efficiency (FOE) and FOPT of 292,674.19 $m^3$. This was followed by HETERO_HIGH_0_8_2.0, with 82.9% FOE and FOPT of 292,342 $m^3$.

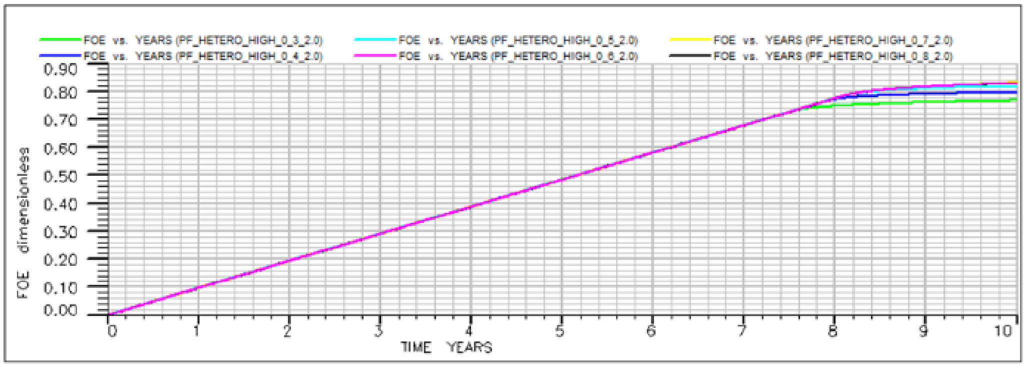


Figure 16. Field oil efficiency for 3, 4, 5, 6, 7 and 8 years of polymer injection

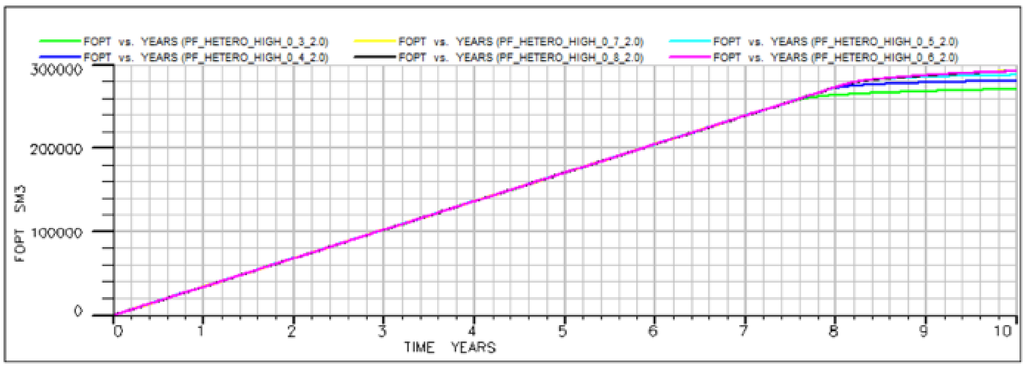


Figure 17. Field oil production total for 3, 4, 5, 6, 7 and 8 years of polymer injection

Figure 16 to 20 shows that all the cases considered followed the same pattern with just slight differences caused by the variation in the years of polymer injection.

The charts are characterized by high efficiencies (Figure 16), high field oil production total (Figure 17), high Field Oil Production rate (Figure 18), late water breakthrough (Figure 19), and favorable pressure decline (Figure 20).

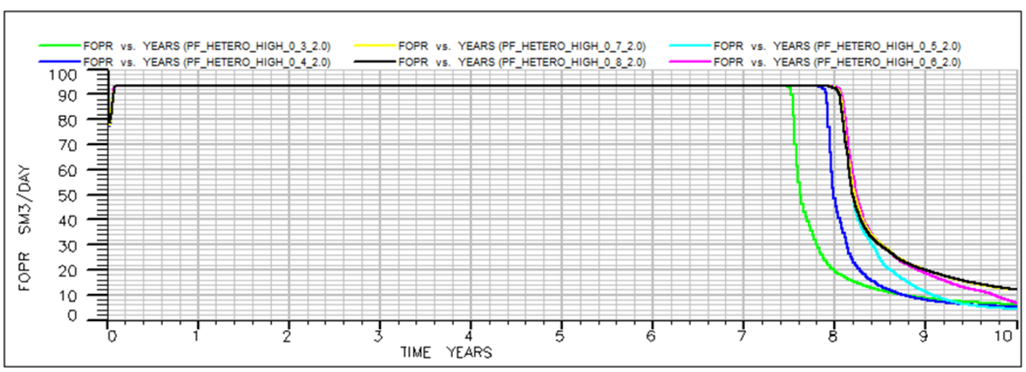


Figure 18. Field oil production rate for 3, 4, 5, 6, 7 and 8 years of polymer injection

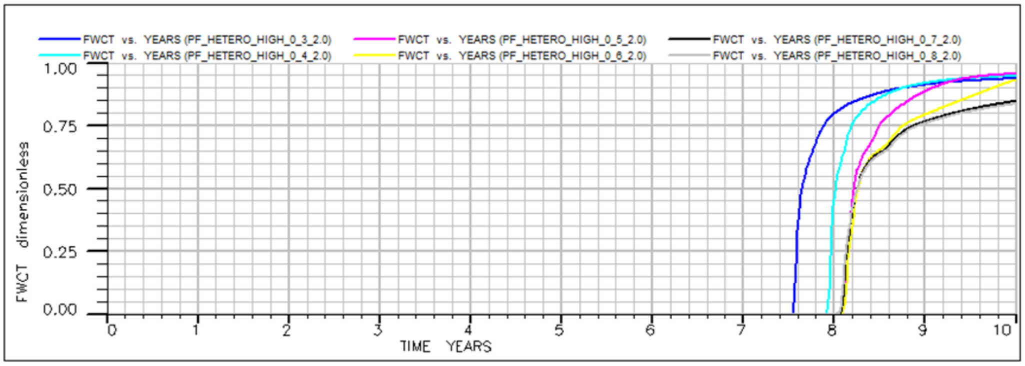


Figure 19. Field water cut for 3, 4, 5, 6, 7 and 8 years of polymer injection

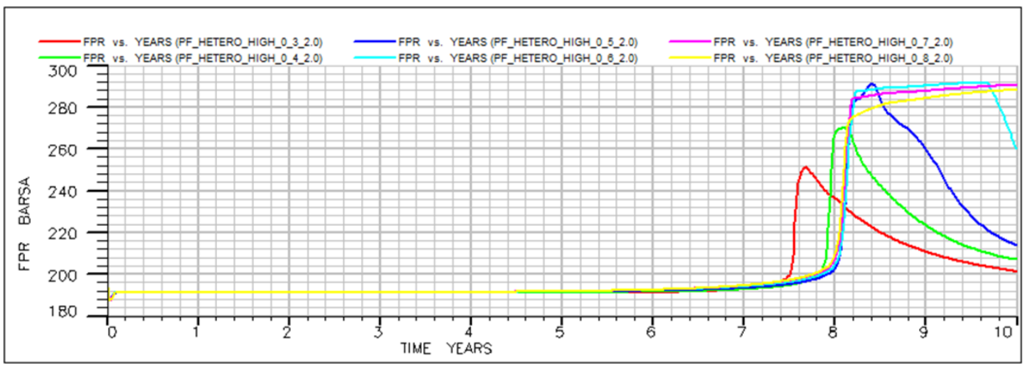


Figure 20. Field pressure for 3, 4, 5, 6, 7 and 8 years of polymer injection

#### *3.2.4. Production period extension*

Having determined the polymer concentration and best reservoir permeability case for the optimum heavy oil recovery, this section examines the effect of production year extension on the overall efficiency and total oil produced. This was achieved by considering an additional production period of five years, making up a total of 15 production years for 7,8,9 and 10 years of polymer injection. The simulation results are shown below in Figure 21 to 25, while the numeric values are given in Figure 26.

The result gives approximately the same field efficiency result for all the cases considered. From Figure 21, the ten years polymer injection case (HETER_HIGH_0_10_15_2.0) gave a maximum FOE of 86% while others gave an efficiency of 85%. Additionally, in Figure 22, the field oil production total for the highest recovery was 304559.66 $m^{3,}$ while the lowest recovery gave 299866.72 $m^3$.

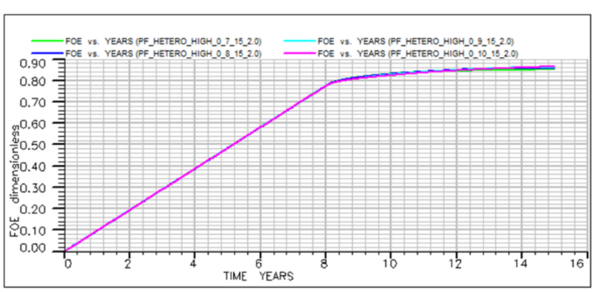


Figure 21. Field oil efficiency (FOE) for 15 years production using 7, 8, 9, 10 years of polymer injection

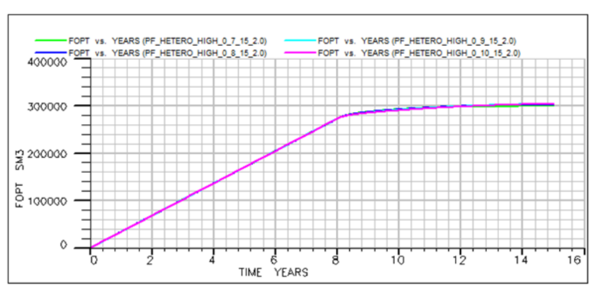


Figure 22. Field oil production total (FOPT) for 15 years production using 7, 8, 9, 10 years of polymer injection

From Figure 23, the pressure can be seen to be sustained for a considerable longer period with a sharp rise in the 8th year for all the cases considered. Additionally, another sharp rise in pressure is seen in the 9th and 10th year for HETER_HIGH_0_9_15_2.0 and

HETER_HIGH_0_10_15_2.0. This is as a result of an additional polymer injection time for these two cases.

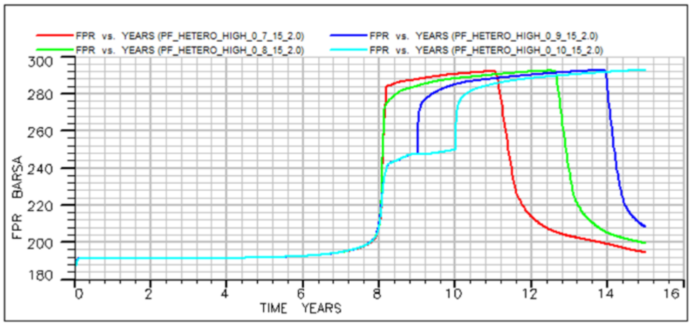


Figure 23. Field pressure (FPR) for 15 years production using 7, 8, 9, 10 years of polymer injection

As expected, an increase in the water cut leads to a decline in the oil production rate. This is reflected in Figures 24 and 25, giving opposite trends of a sharp increase in water cut and decrease in Field Oil Efficiency (FOE) in the 8th year.

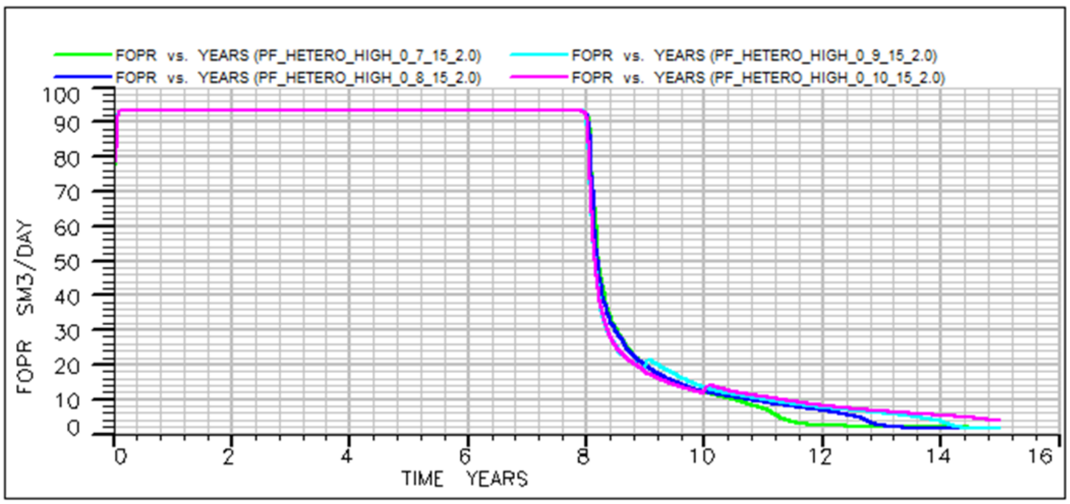


Figure 24. Field oil production rate (FOPR) for 15 years production using 7, 8, 9, 10 years of polymer injection

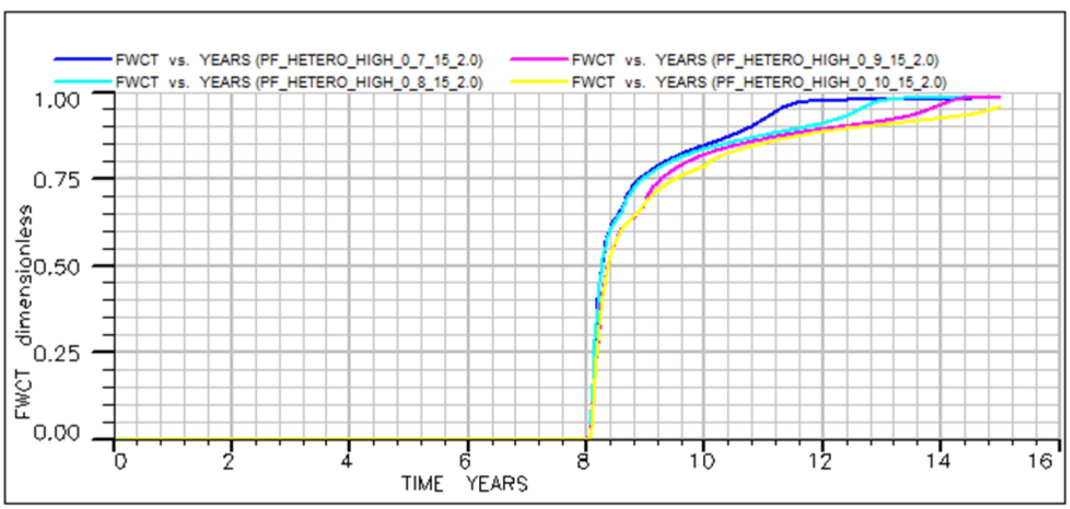


Figure 25. Field water cut (FWCT) for 15 years of production using 7, 8, 9, 10 years of polymer injection

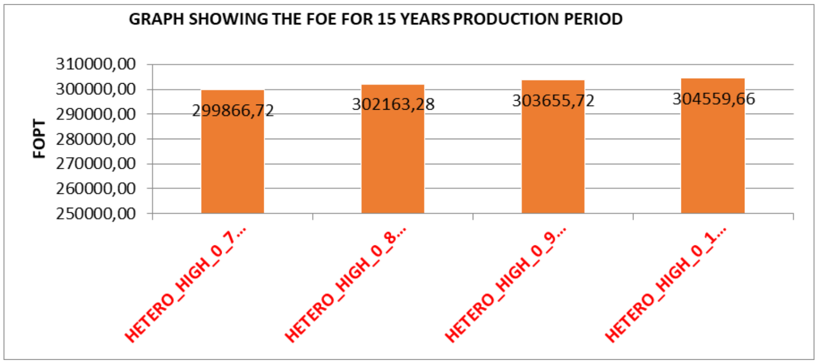


Figure 26. Field oil production total (FOPT) for 15 years of production using 7, 8, 9, 10 years of polymer injection.

## 4. Conclusions

There exist an optimum polymer concentration and injection pattern, which gives optimum recovery for any polymer flooding process. This recovery, however, might not necessarily be proportional to the polymer concentration used. For this study, polymer concentration of 2.0 kg/m$^3$ with 7 years of polymer injection gave the highest recovery.

It was also seen that the earlier the polymer flooding is introduced, the better is the recovery, especially when the reservoir salinity is ignored. A major reason for initial water flooding as practiced in most cases is to reduce reservoir salinity so as to prevent polymer degradation, thereby preparing the rock for polymer flooding.

The simulation results show that the most favorable reservoir pattern for polymer flooding, considering the reservoir properties used in this work is a heterogeneous reservoir with high permeability. Formation permeability is, therefore, a very critical criterion in polymer flooding.

The heterogeneous case gives better results because polymer solution flows along with high permeable layers, decreases the flow rates, and enhances sweep efficiency on low permeable layers. This means oil in high and low permeable layers will be swept out eventually, and high recovery will be obtained.

Appendix. Table A1: Field Oil Efficiency for the first major simulation case, 10 years simulation period

| | FOE (HOMO_LOW) | FOE (HOMO_HIGH) | FOE (HETERO_LOW) | FOE (HETERO_HIGH) |
|---|---|---|---|---|
| Copolymer (kg/m$^3$)= 1 | | | | |
| 1 year polymer injection | 55% | 66% | 66% | 65% |
| 2 years polymer injection | 57% | 70% | 69% | 70% |
| 3 years polymer injection | 59% | 72% | 71% | 73% |
| Copolymer (kg/m$^3$)= 2 | | | | |
| 1 year polymer injection | 54% | 67% | 64% | 67% |
| 2 years polymer injection | 55% | 72% | 68% | 73% |
| 3 years polymer injection | 56% | 75% | 71% | 77% |
| Copolymer (kg/m$^3$)= 3 | | | | |
| 1 year polymer injection | 63% | 61% | 64% | 53% |
| 2 years polymer injection | 53% | 68% | 64% | 71% |
| 3 years polymer injection | 53% | 70% | 66% | 74% |
| Copolymer (kg/m$^3$)= 4 | | | | |
| 1 year polymer injection | 53% | 64% | 62% | 66% |
| 2 years polymer injection | 53% | 69% | 66% | 72% |
| 3 years polymer injection | 54% | 72% | 68% | 75% |
| Copolymer (kg/m$^3$)= 5 | | | | |
| 1 year polymer injection | 53% | 65% | 62% | 67% |
| 2 years polymer injection | 54% | 70% | 67% | 72% |
| 3 years polymer injection | 54% | 73% | 69% | 75% |

***Acknowledgment***

*The authors appreciate the management of the African University of Science and Technology (AUST) for the provision of the resources used to carry out this research work, as well as Gloria Kasimbazi for the system of naming adopted in this work.*

**References**

[1] Saboorian-Jooybari H, Dejam M & Chen Z. Half-Century of Heavy Oil Polymer Flooding from Laboratory Core Floods to Pilot Tests and Field Applications. Society of Petroleum Engineers. 2015; https://doi.org/10.2118/174402-MS .

[2] Abidin AZ, Puspasari T, Nugroho WA. Polymers for Enhanced Oil Recovery Technology. Procedia Chemistry, 2012; 4, 11–16. https://doi.org/10.1016/j.proche.2012.06.002

[3] Akpan EA, Ogolo O, Ogiriki O, Kaita YA & Amune D. Numerical Simulation of Enhanced Oil Recovery using Gum Arabic Polymer. Pet Coal, 2019; 61(4): 660-671.

[4] Bento H, De LI, Moreno RBZL. Evaluation of Heavy Oil Recovery Factor by Water Flooding and Polymer Flooding at Different Temperatures. SPE Latin America and Caribbean Heavy and Extra Heavy Oil Conference, 2016: https://doi.org/10.2118/181193-ms

[5] Firozjaii AM, Saghafi HR. Review on chemical enhanced oil recovery using polymer flooding: Fundamentals, experimental and numerical simulation. Petroleum. 2019; In Press. https://doi.org/10.1016/j.petlm.2019.09.003

[6] Pei H, Zhang G, Ge J, Jiang P, Zhang J, Zhong Y. Study of polymer-enhanced emulsion flooding to improve viscous oil recovery in water flooded heavy oil reservoirs. Colloids and Surfaces A: Physicochemical and Engineering Aspects, 2017; 529: 409–416. https://doi.org/10.1016/j.colsurfa.2017.06.039

[7] Vela S, Peaceman DW, Sandvik EI. Evaluation of Polymer Flooding in a Layered Reservoir with Crossflow, Retention, and Degradation. Society of Petroleum Engineers Journal, 1976; 16(02): 82–96. https://doi.org/10.2118/5102-pa

[8] Chang HL. Polymer Flooding Technology Yesterday, Today, and Tomorrow. Journal of Petroleum Technology, 1978; 30(08): 1113–1128. https://doi.org/10.2118/7043-pa

[9] Green WD and Willhite GP. Enhanced Oil Recovery. Henry L. Doherty Memorial Fund of AIME, Society of Petroleum Engineers Text Book Series. 1998, ISBN-13: 978-1555630775.

[10] Jung JC, Zhang K, Chon BH, Choi HJ. Rheology and polymer flooding characteristics of partially hydrolyzed polyacrylamide for enhanced heavy oil recovery. Journal of Applied Polymer Science, 2012; 127(6): 4833–4839. https://doi.org/10.1002/app.38070

[11] Rellegadla S, Prajapat G, Agrawal A. Polymers for enhanced oil recovery: fundamentals and selection criteria. Applied Microbiology and Biotechnology, 2017; 101(11): 4387–4402. https://doi.org/10.1007/s00253-017-8307-4

[12] Seright R. Potential for Polymer Flooding Reservoirs with Viscous Oils. SPE Reservoir Evaluation & Engineering, 2010; 13(04): 730–740. https://doi.org/10.2118/129899-pa

[13] Sheng J. Modern Chemical Enhanced Oil Recovery: Theory and Practice. Gulf Professional Publishing. 2010, eBook ISBN: 9780080961637.

[14] De Melo MA., da Silva IPG., de Godoy GMR, Sanmartim AN. Polymer Injection Projects in Brazil: Dimensioning, Field Application and Evaluation. SPE/DOE Improved Oil Recovery Symposium, 2002; https://doi.org/10.2118/75194-ms

[15] Sheng JJ, Leonhardt B, Azri N. Status of Polymer-Flooding Technology. Journal of Canadian Petroleum Technology, 2015; 54(02): 116–126. https://doi.org/10.2118/174541-pa

[16] Stahl GA and Schulz DN. Water-Soluble Polymers for Petroleum Recovery. New York City: Springer, 1988, ISBN 978-1-4757-1985-7.

[17] Kasimbazi G. Polymer Flooding. Master's Thesis Norwegian University of Science and Technology 2014.

*To whom correspondence should be addressed: Mujeeb B. Adetayo, Petroleum Engineering Department, African University of Science and Technology, Abuja, Nigeria, E-mail: madetayo@aust.edu.ng*