Petroleum and Coal

**Article** **Open Access**

# NUMERICAL SIMULATION OF ENHANCED OIL RECOVERY USING GUM ARABIC POLYMER

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Received March 12, 2019; Accepted May 21, 2019

**Abstract**

The era of easy oil is diminishing fast, and companies are looking for oil in remote and hazardous terrains. This, combined with low oil prices, makes drilling for new reserves very expensive and risky. This then considers enhanced oil recovery processes, which increases the amount of oil that can be recovered from a reservoir. This study was aimed at determining the suitability of Gum Arabic as a polymer for EOR operations using numerical simulation. This was done by matching core flooding experiments using Eclipse. The simulation results gave a waterflood oil recovery match of 53% as compared with the experimental recovery of 55% while ASP flooding gave an oil recovery match of 80.53% as compared with the experimental recovery of 82%. Upscaling from core to field simulation, the ASP slug formulated increased field total oil production by increasing recovery from 62.48% at the end of the water flooding to 85.8%. This indeed shows the potential of gum Arabic for EOR operations.

***Keywords***: *Numerical simulation; Gum Arabic; Enhanced Oil Recovery; Alkaline Surfactant Polymer; Eclipse.*

## 1. Introduction

The average recovery factor for both primary and secondary conventional recovery technique is about 33%. This shows that over 60% of the original in place oil is still left unrecovery. This amount of oil was either passed by the injected water, or there were too viscous to be displaced by the water injected [1-5]. Kevin and Raymond [6] noted that recovery depends on several factors that include: reservoir properties, existing technology, nature of crude oil, and prevailing economic climate.

Water injection tends to resuscitate the pressure of a depleted reservoir, and it displaces the oil to producers. However, water has high mobility, and it is less viscous. This makes it evade large volumes of oil, and "break-through," to the producing well before adequately sweeping the reservoir [8] resulting in only part of the reservoir being contacted for a realistic time frame and injection scheme. Also, the reservoir heterogeneity aggravates the injected water's tendency to only mobilize the oil in regions with high permeability, which leads to an early breakthrough in that region [7].

Chemical flooding methods are usually seen as a special branch of enhanced oil recovery processes to produce the remaining oil after water flooding process has been carried out [5-12]. The performance of the chemicals used, however, varies depending on the particular reservoir rock and fluid properties. Therefore core flood experiments at the laboratory scale are required to evaluate the performance of various chemicals and their impacts on the reservoir rock and crude oil properties [8, 13]. Nowadays, as all field operations are ultimately studied through simulation models of some forms, it is important also that simulation technology is on par with all relevant experimental findings [8].

Over the years, flooding techniques have been done in various forms; surfactant polymer flooding, alkaline polymer flooding, alkaline surfactant flooding, and alkaline surfactant polymer flooding (ASP) [1, 3-4, 10, 14- 21]. ASP has proven from experimental studies to be among one of the chemical flooding processes with the highest recovery factor, and it has been conventionally carried out using polymers like Xanthan gum and partially hydrolyzed polyacrylamide which is not readily available in Nigeria [17, 22- 25]. The polymer used in this study is gum Arabic because it is a polysaccharide and has a similar molecular structure to Xanthan gum, and it is commercially available in Nigeria. There are many experiences on ASP flooding using Xanthan gum and other polymers, but very few on gum Arabic. The aim is this research work is to determine the suitability of gum arabic as a polymer for EOR operations using numerical simulation [5, 14, 26- 28].

## 2. Literature review

Alkaline-surfactant-polymer (ASP) flooding is an EOR process, in which alkali, surfactant, and polymer are injected at the same time. It has been considered as the most promising chemical methods because it is possible to achieve interfacial tension reduction, wettability alteration, and mobility control effectively [29]. Although the method of surfactants and alkaline solution injection which converts naturally occurring naphthenic acids in crude oils to soaps have long been used to increase oil recovery, key concepts such as the need to achieve ultralow interfacial tensions and the means for doing so using microemulsions were not clarified until a period of intensive research between approximately 1960 and 1985.

Nelson *et al.* [30] recognized that in most cases, the soaps formed by injecting alkali would not be at the "optimal" conditions needed to achieve low tensions. They, therefore, proposed that a relatively small amount of a suitable surfactant be injected with the alkali so that the surfactant/soap mixture would be optimal at reservoir conditions. With polymer added for mobility control, the process would be an alkaline-surfactant-polymer (ASP) flooding.

Hawkins *et al.* [31] reported that the simultaneous injection of alkali and polymer is more effective than the same chemicals injected sequentially with no contact between alkali and polymer. Tong *et al.* [32] reported that the main mechanisms of ASP flooding are interface producing, bridging between inner-pore and outer-pore, and oil-water emulsion. Alkali substances have proven to be an appropriate means to improve the oil recovery from oil-wet reservoirs by reversing the rock wettability to a more favorable condition. Wettability alteration function is predominant at alkali concentration lower than 1% by weight, whereas IFT reduction is oppositely predominant at a higher concentration than 1% by weight [33].

Onuoha and Olafuyi [17] came up with a laboratory study on the use of gum arabic for mobility control. In an ASP flooding they conducted, the displacement efficiencies of two ASP slugs were compared and calculated to be 90.2% for sodium hydroxide (NaOH), lauryl sulphate and gum Arabic slug and 77.9% for sodium hydroxide, Tween 80 and gum Arabic slug. Their work was on light oil in a water-wet unconsolidated glass beads core. Many ASP flood laboratory test and field tests or applications have been done over the years with the use of other polymers such as xanthan, scleroglucan, polyacrylamide, and other cellulose derivatives.

Taiwo *et al.* [25] showed that oil recovery by the imbibition process does not follow a regular pattern. It reveals some complexities in the oil mobilization process and an uneven pattern in the oil recovery due to the simulated reservoir heterogeneity. They showed that it is not only the grain size of the reservoir rock but also the arrangement of the grains in the core affect the oil recovery. They showed that water flooding could recover about 70% while ASP flooding can recover between 16 to 19% of the original oil in place from the synthesized heterogeneous beads pack. Bernheimer core gives the best results for ASP EOR flooding operations. Avwioroko *et al.* [34] showed that oil recovery increases as formation become more strongly water wet. They showed that the displacement efficiency of water floods and ASP flooding is markedly affected by the wettability of the core. The wettability is one of the important factors to determine the oil recovery of water and ASP flooding. Water-wet and oil-wet conditions are favorable to obtain high enhanced oil recovery for ASP flooding.

## 3. Methodology

### 3.1. Matching laboratory experiments using numerical simulation

Studies have shown that a better displacement efficiency can be achieved within a range of polymer concentration and that the performance of ASP flood program is dependent on the right slug formulation, the injection rate and the overall project design [25]. Therefore we need to determine the appropriate formulation of this slug and verify its formulation with core flood experiment. The core flood experiment which this work simulated was done by Onuoha and Olafuyi [17] at the EOR lab at the University of Benin, Nigeria and the composition of the Alkaline Surfactant Polymer (ASP) slug used for the experiment are given in Table 1. The properties of the core sample are given in Table 2. While Table 3 gives a summary of the results gotten from the core flooding experiment. The PVT properties of the reservoir fluid used for the core flooding experiment are listed in Table 4. The values of maximum relative permeability ($K_{rw\_max}$ and $K_{ro\_max}$) were used in plotting the relative permeability curves using Corey equation.

Table 1. Chemical slug composition [17]

| Materials | Names | Concentration |
|---|---|---|
| Alkaline | Sodium hydroxide (NaOH) (98%) | 1.0wt % |
| Surfactant | Sodium dodecyl sulfate (SDS) | 0.3wt % |
| Polymer | Gum Arabic | 5 000 ppm |

Table 2. Core properties [17]

| Core properties | Values |
|---|---|
| Core type | Class IV soda lime glass spheres |
| Length (cm) | 25.6 |
| Bulk volume ($cm^3$) | 112.93 |
| Porosity (%) | 0.3367 |
| Pore volume (PV) ($cm^3$) | 38 |
| Permeability (mD) | 1540 |
| Oil flow rate ($cm^3$/h) | 60 |
| Waterflood rate ($cm^3$/h) | 60 |

Table 3. Results gotten from the core flooding experiments [17]

| Initial oil saturation | 82% |
|---|---|
| Initial water saturation | 18% |
| Water flood | |
| Oil recovered | 19.5 $cm^3$ |
| Recovery | 55 % |
| Residual oil | 45 % |
| Asp flood | |
| Additional oil recovered | 11.5 $cm^3$ |
| Cumulative oil recovered | 31 $cm^3$ |
| Recovery | 36.9 % |
| Residual oil | 8.1 % |
| Residual recovery | 82 % |

Table 4. Core flooding PVT properties [17]

| PVT properties | Values |
|---|---|
| Initial water saturation | 0.18 |
| Residual oil saturation | 0.45 |
| $K_{rw\_max}$ | 0.8 |
| $K_{ro\_max}$ | 0.4 |
| Water viscosity (cP) | 0.32 |
| Water sensity (lb/$ft^3$) | 62.37 |
| Oil density (lb/$ft^3$) | 57.76 |
| Water compressibility ($psi^{-1}$) | 3.03E-06 |
| Reference pressure (psia) | 118 |

#### *3.1.1. Coreflooding simulation*

A 1D model was developed in Eclipse™ by approximating a cylindrical plug into cuboidal rock sample. Then the cuboid is divided into 100 grid cells, as shown in Figure 1.

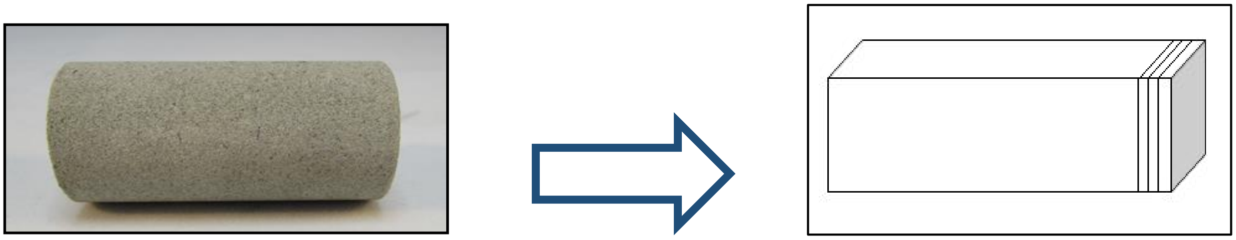


Figure 1. Scheme for approximating a cylindrical plug into cuboidal rock sample

The Eclipse model gave a pore volume of 38 cm$^3$, which is the same as the experimental pore volume. This model is maintained at a simplistic level to ensure small simulation time, along with ease of modification and debugging. Grid cells of 20, 50, 100, 200, and 500 were used to check for the optimum grid cells to use.

### 3.1.2. Dynamic simulation constraints

The dynamic model is bounded with the following constraints, as per laboratory experiments:

#### *3.1.2.1. Initial constraints*

Constant bottom-hole pressure at producing well = 118 psia = 8.02945 atma. This pressure is lower than the actual reservoir condition. However, due to the absence of any gas in the reservoir, this difference in pressure will not alter the flooding to a large extent. Constant inlet flow rate = 1mL/min = 60cm$^3$/hr.

#### *3.1.2.2. Assumptions*

- The core is completely homogenous,
- Corey law is applicable for relative permeability curves.

Corey law:

$$K_{rw}\ (S_w) = K_{rw,or}\ \left(\frac{S_w - S_{cw}}{1 - S_{cw} - S_{or}}\right)^{n_w} \quad (1)$$

$$K_{ro}\ (S_w) = K_{ro,cw}\ \left(\frac{1 - S_w - S_{or}}{1 - S_{cwi} - S_{or}}\right)^{n_w} \quad (2)$$

where: $K_{ro,cw}$ is oil relative permeability at minimum water saturation; $S_{cw}$ is critical water saturation; $S_{cwi}$ is initial water saturation; $S_{or}$ residual oil saturation; $N_o$ & $N_w$ are Corey oil exponent.

Residual oil saturation values are found with terminal values of flooding of water and ASP. In the simulator, all the grid blocks were set at initial saturation. The water flood and ASP process were simulated to generate the oil production curve and oil recovery.

Table 5. Dynamics of flooding

| Component | Concentration (ppm) | Approximate Slug Size (PV) |
|---|---|---|
| Initial waterflood | | 7 |
| ASP Flood | | |
| Alkali | 10,000 | 0.3 |
| Polymer | 5000 | |
| Surfactant | 3000 | |
| Final Water Flood | | 8 |

## 4. Results and discussion

A simple 100 * 1 * 1 model was built (using Eclipse™) with injection in the first cell and production in the last cell. Figs. 2 and 3 shows the saturation map for both the water and oil flooding, respectively in the core as shown by Floviz at the beginning of the flooding simulation. The simulation results show that after injecting 7 PV of water into the core model, the continual injection does not bring about additional recovery as the model is now producing at almost

100% water cut. History Matching is a common reservoir engineering technique to update a geological model. The reservoir model is modified to match the response of the field during the production phase, and further extrapolated to predict the future response of the reservoir. This method is commonly used to fit oil production trend and Bottom Hole Pressure (BHP).

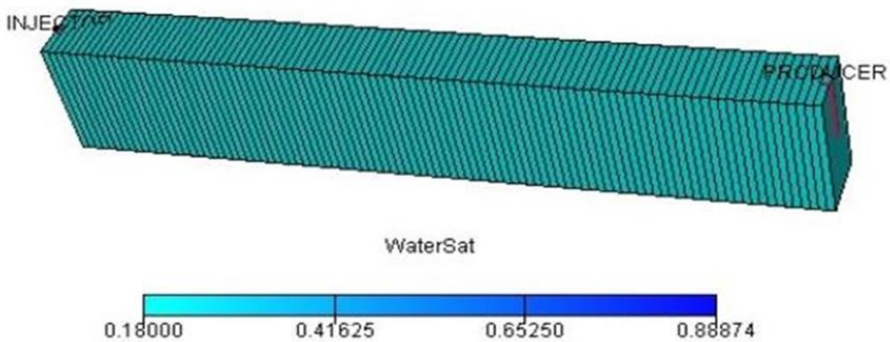



Fig 2. Water saturation map in flooding experiment.

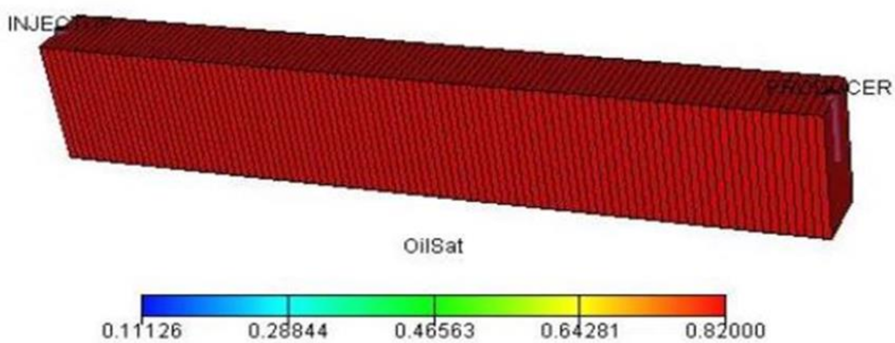



Fig 3. Oil saturation map in flooding experiment.

Figs. 4, 5 and 6 show the plot of oil recovery vs. pore volume of water injected, the plot of water cut vs. pore volume of water injected and total oil produced vs. pore volume of water injected respectively.The simulation model was able to show a total oil production of 19.17cm$^3$; this gives a waterflood recovery of 53% as compared with a total oil production of 19.5 cm$^3$ and recovery of 55% from the experimental core flood.

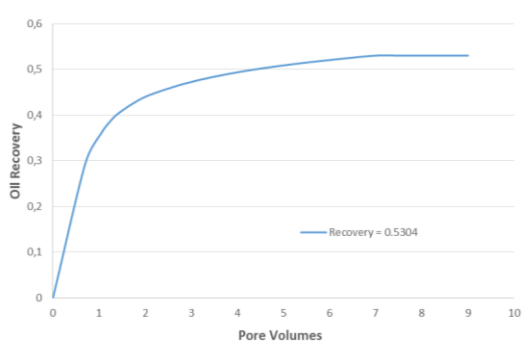



Fig. 4. Oil Recovery match for water flooding

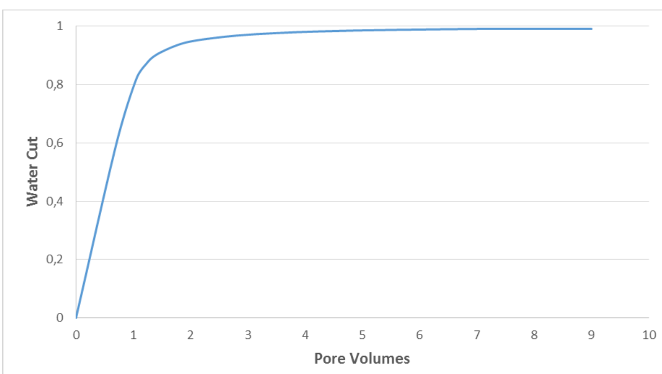



Fig. 5. Water cut match for water flooding

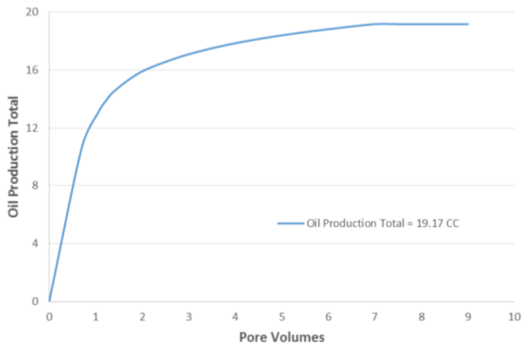



Fig. 6. Oil production total match for water flooding

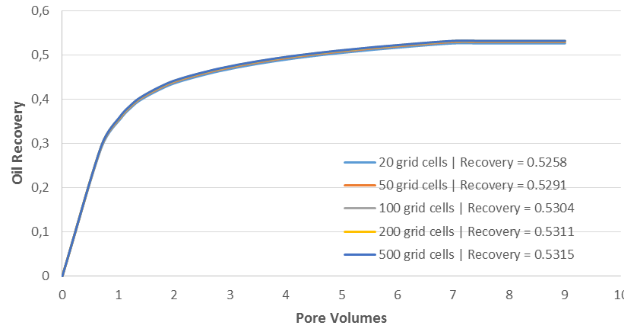



Fig. 7. Oil recovery variation with No of model grid cells

Before beginning the simulation work, a sensitivity analysis was performed to see which number of grid cell would give a result closest to the experimental results. Grid cells of 20, 50, 100, 200, and 500 were used to check for the optimum grid cells to use. From Fig. 7, it was concluded that for this simulation model, grid cell variation has little to no effect on the oil recovery as they gave a recovery ranging from 52% to 53%.

Having matched the water flood, simulation of the alkaline surfactant polymer (ASP) flooding started. Table 6 shows a summary of the flooding results. The simulation model was able to show a total oil production of 29.12 $cm^3$; this gives the ASP flood recovery of 80.53% as compared with a total oil production of 31.0 $cm^3$ and recovery of 82% from the experimental core flood. This is seen in Fig. 8.

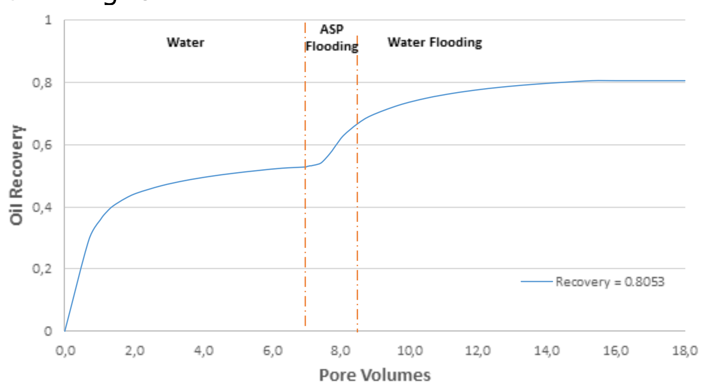



Fig. 8. Oil recovery for ASP flooding

The rise in oil recovery is due to alterations of the contact angle between oil-water-rock equilibrium to mobilize more oil; due to the presence of alkali and surfactant.

Table 6. Flooding results summary

| Parameter | Core flooding model | Simulation model |
|---|---|---|
| | Waterflood | |
| Oil recovered | 19.5 $cm^3$ | 19.17 $cm^3$ |
| Recovery | 55 % | 53.04 % |
| | ASP Flood | |
| Oil recovered | 31 $cm^3$ | 29.12 $cm^3$ |
| Recovery | 82 % | 80.53 % |

### 4.1. Sensitivity analysis

This involves the study of the effect of alterations in individual parameters of the system on final outputs. Trends of variations of output parameters with the marginal change of an input parameter are plotted. Also, extreme cases are generated to rectify boundary assumptions. Sensitivity analysis plays an important role to understand systems with multiple variable parameters. Core flooding is dependent on different parameters, so sensitivity analysis is often used to explore optimized flooding in reservoirs as well as plugs. The parameters for the sensitivity analysis are shown in Table 7.

Table 7. Sensitivity analysis parameters summary

| Parameter | Base case | Sensitivity analysis values/multipliers |
|---|---|---|
| Injection Rate | 60 $cm^3$/hr | Keeping injection time constant: $cm^3$/h<br>Keeping injected PV constant: 30 $cm^3$/h, 90 $cm^3$/h and 120 cm3/h |
| PV of ASP Injected | 0.3 PV | PV variation at 0.1, 0.5, 1.0 and 1.5 PV of ASP injected |
| Viscosity (polymer concentration) | 5000 ppm | Viscosity variation with polymer concentration Variation: 0 ppm, 500 ppm, 2500ppm, & 10000 ppm |

### 4.2. Injection rate

Initially, models that were generated for sensitivity analysis of injection rate had equal pore volume injected of each phase, as the base case. This was achieved by adjusting injection time. One model was developed with half of the volume injected at each stage of injection, without altering total injection time. So total pore volume injected became half. Injection rate is one of the important parameters to be adjusted in reservoir engineering because of following pros and cons:

- Injection rates are limited by fracking pressure. Above certain pressure, there is a risk of fracking the reservoir, creating a loss of injection water to some uncertain point of reservoir.
- Higher injection rate will increase production rate; saving money in terms of time
- Higher injection rate have a higher risk of un-swept oil volume (poor volumetric sweep efficiency if not monitored well)

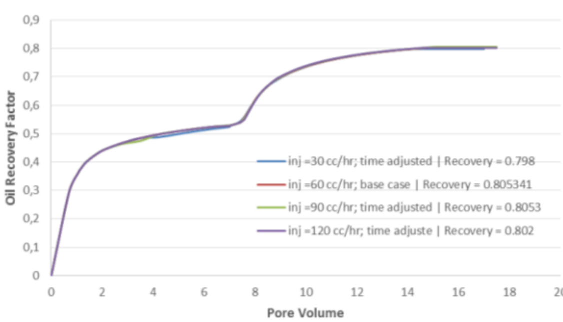



Fig. 8. Injection rate sensitivity with constant volume

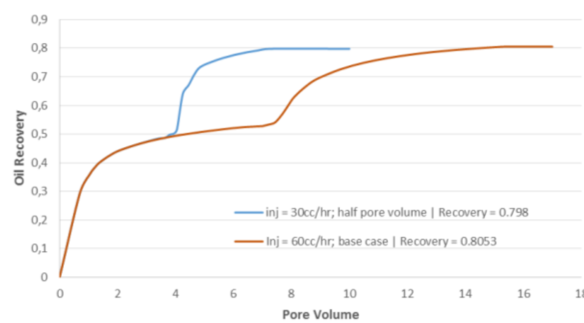



Fig. 9. Injection rate sensitivity with injection time

All injections rates (for constant pore volume injection) show similar production behavior (Fig. 8). Despite injecting lower injection volume, simulation of injection rate of 30$cm^3$/hr reached almost similar total oil recovery factor (Fig. 9). This can be explained with the long injection of water flooding to achieve a steady state.

### 4.3. Viscosity (polymer concentration)

Viscosity variation is mainly caused by the polymer concentration. As discussed earlier, polymers give stable waterfront to flooding. This results in higher volumetric sweep efficiency. Followings are the pros and cons of the polymer concentration variation:

- Higher polymer concentration will injection pressure; resulting in increase injection cost
- Lower polymer concentration will not create stable waterfront, might cause fingering effect
- Higher polymer viscosity can cause blockage of small pore size at the injection point, resulting in reduced efficiency of the injector well.

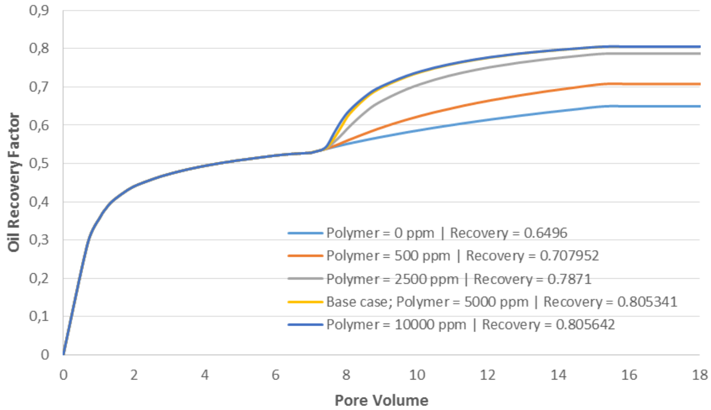
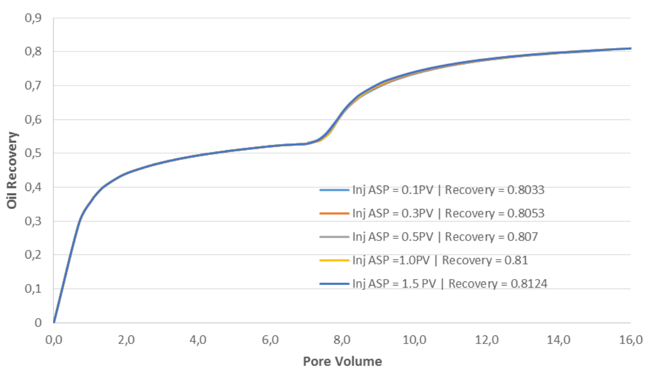



Fig. 10. Results of sensitivity analysis for polymer concentration

With increasing polymer concentration, recovery factor increased (Fig. 10). However, in the lower range of polymer concentration, the marginal increase in recovery factor is higher compared to the marginal increase in a higher concentration of polymer. This can be attributed to the stabilization of the waterfront. Due to stable waterfront above 5000ppm, polymer concentrations above it resulted in almost equal recovery factor but at higher injection cost.

## 4.4. PV of ASP injected




Sensitivity analysis on the pore volume of the ASP injected was carried out to identify the optimum value of ASP slug, which should be injected. With increasing pore volume of ASP slug injected, recovery factor also increased although the increase was very minimal (Fig. 11).

Fig. 11. Results of sensitivity analysis for PV of ASP injected

## 4.5. Field simulation model

Assuming a synthetic reservoir of three layers with varying permeabilities, a 10x10x3 grid was built in Eclipse with negligible capillary pressure to run a 3D field-scale reservoir simulation. The flow rates of both the injection and production wells are set at 1258 stb/d. All the characteristics of the model have been summarized in Table 8. The reservoir PVT properties is and dynamics for the ASP flooding for the reservoir shown in Table 9 and Table 10, respectively.

Table 8. Eclipse model characteristics

| | Layer 1 | Layer 2 | Layer 3 |
|---|---|---|---|
| Blocks | 100 | 100 | 100 |
| Reservoir pop depth | 2600ft | 2600ft | 2600ft |
| Layer depth | 0.58ft | 0.84ft | 0.47ft |
| Porosity | 25% | 25% | 25% |
| Permeability X and Y | 4500md | 3300md | 2400md |
| Permeability Z | 1050md | 1800md | 500md |

Table 9. Reservoir PVT properties (SI Units)

| PVT properties | Values |
|---|---|
| Initial water saturation | 0.2 |
| Residual oil saturation | 0.3 |
| $K_{rw\_max}$ | 0.8 |
| $K_{ro\_max}$ | 0.5 |
| Water viscosity | 0.88 |
| Water density | 998 |
| Oil density | 850 |
| Water compressibility | 4.6 E-06 |
| Reference pressure | 270 |

Table 10. Dynamics of ASP flooding for reservoir

| Component | Concentration (ppm) | Approximate flooding duration (days) |
|---|---|---|
| Initial waterflood | | 600 |
| ASP Flood | | |
| Alkali | 10,000 | 50 |
| Polymer | 5000 | |
| Surfactant | 3000 | |
| Final Water Flood | | 600 |

The saturation maps below give the STOIIP of the reservoir during the simulation process. Fig 12 shows the initial oil saturation before the flooding started. On injecting water, we notice how the saturation profile changes as the injected fluid move towards the producer (Fig. 13)

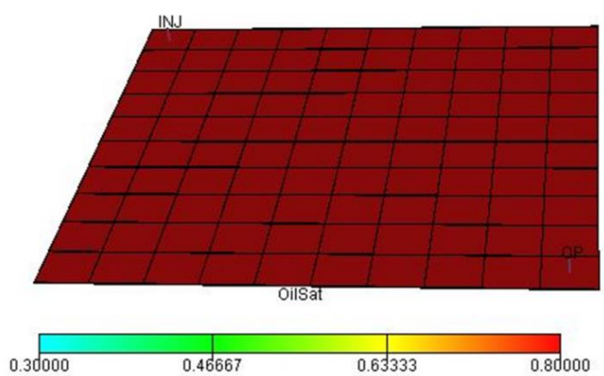



Fig. 12. Oil saturation map in the reservoir at the beginning of the simulation

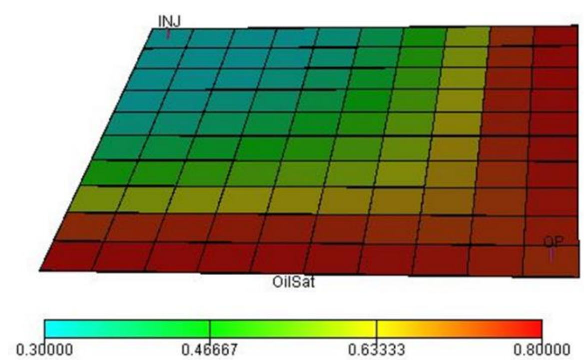



Fig. 13. Oil saturation map in the reservoir during the water flood simulation

After about 400 days of water injection, the oil saturation in the reservoir no longer changes with a continual injection of water (Fig. 14).

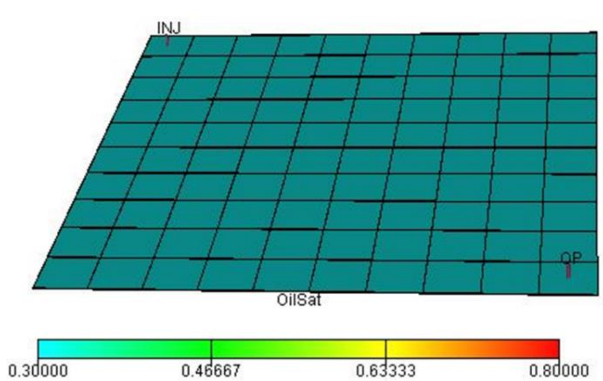



Fig. 14. Oil saturation map at the end of the waterflood simulation

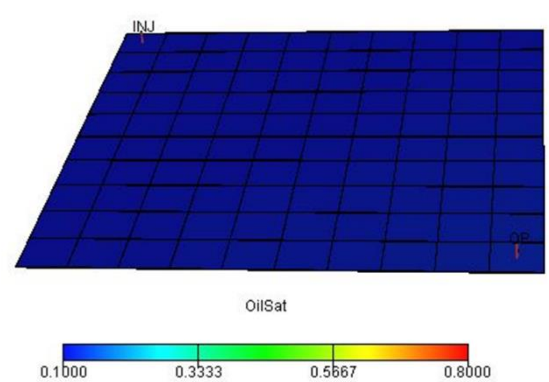



Fig. 15. Oil saturation map at the end of the ASP flood simulation

We then turned to the injection of our ASP slug, followed by water flooding. The field study has proved that the ASP slug formulated is effective has it reduced the oil left the reservoir as shown in the saturation maps (Fig. 15).

The total oil production and oil recovery increased from 10516.51 STB and 62.48 % at the end of the water flooding to 14387.325 STB and 85.8% (Fig. 16) respectively on the addition of an ASP slug. This is an additional recovery of 3870.815 STB.

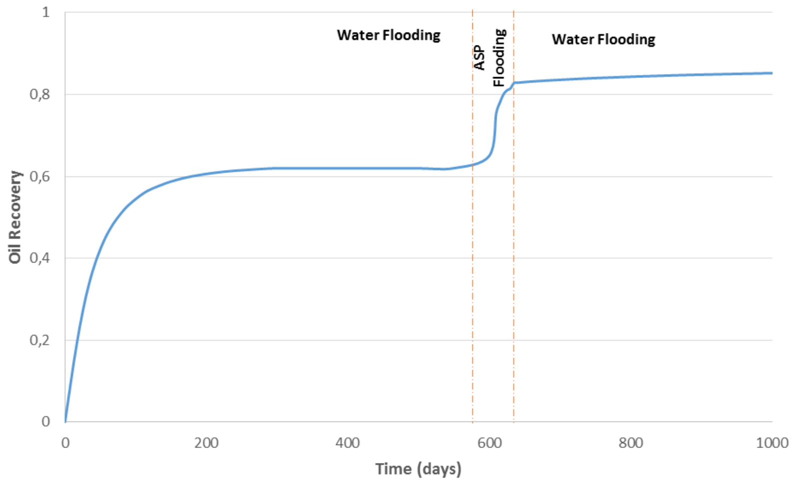



Fig. 16. Oil Recovery profile for ASP flooding of the synthetic reservoir

## 5. Conclusion

This study showed that the numerical simulation of ASP core flooding using Gum Arabic as a polymer could be done using Eclipse as the simulator. This was done by matching a core flooding experiment using Gum Arabic and formulating an optimal ASP system that reduces residual oil saturation to a minimum to improve oil recovery.

Grid cell variation has little to no effect on the oil recovery on the core as they gave a recovery ranging from 52% to 53% with water flooding. Sensitivity analysis of injection rates (at constant pore volume injected) showed similar production behavior. Despite injecting lower injection volume, (similar injection time), a lower injection rate reached almost similar total oil recovery factor with a long injection of water flooding to achieve a steady state.

Sensitivity analysis of viscosity showed an expected trend of increasing viscosity of injected flooding resulting in increased oil production.Sensitivity analysis on the pore volume of the ASP injected showed recovery factor increased with an increasing pore volume of ASP slug injected, although the increase was very minimal.

Extrapolating from core to field simulation, the ASP slug formulated was able to increase field total oil production by increasing recovery from 62.48 % at the end of the water flooding to 85.8%. Gum Arabic has proven to be an effective polymer for EOR operations based on the numerical simulation results obtained.

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