Enhanced Oil Recovery in Iraqi Limestone Formation by Intermittent Injection of Xanthan.

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Abstract. Enhanced oil recovery consists of three major methods which are miscible Method, thermal method and chemical method. Polymer flooding is considered as one of the chemical method which is economical compared to other methods. The main objective of this project is to determine the optimum polymer concentration that will bring in the most recovery of a large full-field flooding project at Ahdeb oil field. Thus, the (1) polymer concentration, (2) polymer solution viscosity, and (3) polymer injection rate affects towards oil recovery are investigated. This investigation will solely base on the outcome from the Simulator. The main difficulty in the recovery of oil is the viscosity of oil is higher than injection fluid viscosity, which makes displacement by a low-cost fluid, such as water or gas; inefficient on account of the “unfavorable” mobility ratio (i.e. mobility of the injected fluid is greater than the mobility of the oil). Since improvement in the mobility ratio is the ultimate goal, viscosity of the injected fluid is increased by addition of soluble polymer. The polymer concentrations were varied so that different polymer solution viscosity can be injected into the model. Apart from improvement in the mobility ratio, average pressure of the reservoir will also be maintained for as long as possible, which would lead to an improvement in the oil recovery. In accordance to that, the injection rates of displacing fluid play an important role in maintaining Average reservoir pressure and also the period of polymer flooding. The scope of the study will mainly focus on the polymer injection-water cut relationship. The research methodology used in this study is by varying polymer concentration, polymer solution viscosity and the polymer injection rate, the resulting cumulative oil production and average reservoir pressure will be taken into consideration for each case. From the optimized model, it shows that increment in polymer solution viscosity (increment in polymer solution concentration) increases the oil recovery, but when it exceeds its optimum point, oil recovery stabilized. There are a total of six cases run in this study concerning the polymer solution concentration. It proves that the addition of polymer concentration can give additional recovery up to a certain level, before it maintained. Adjusting the injection rate will be constrained by polymer concentration to maintain the injection bottom-hole pressure below formation fracture pressure since higher concentration requires more energy to move the polymer consequently increase the injection bottom hole pressure. In summary, Polymer flooding allows more oil recovered from the mature oil fields to maintain high oil production. If verified by experiment, this model of polymer behavior may have impact on reducing the residual oil saturation and consequently increase the economic life of the fields.
1. Introduction

For more than 20 years polymer flooding has been executed in conventional (light to medium oil) reservoirs. The ultimate recovery expectancy of 50% and 10-15% incremental oil recovery over water flooding have been achieved (1).

Nowadays, most of the reservoir engineers all over the world concern about increasing the oil recovery from the mature reservoirs, the common techniques that has been used are related to the Enhanced Oil Recovery (EOR) with different methods. One of the most effective techniques is the chemical flooding, by using Polymer. This project studies the effect of Polymer flooding on the recovery of the oil in (Kh) formation in Ahdab mature oil field in Iraq. A large quantity of oil reserves is found in residual form and about 60% of the original oil in place (OIIP) which left without recovery has to be found in this carbonate formation. The major challenge was the quality of injection water and the field heterogenety.

Objectives

This project will present a comprehensive simulation study about the impact of the polymer chemical flooding in the Ahdab oil field Carbonate Reservoirs in order to improve the oil recovery. So the objectives of this project are to:

- Evaluate the performance of the Polymer injected. Polymer will be used as the main chemical solution.
- Construct different model scenarios of injecting a combination of (Polymer concentration, Viscosity and injection rate)

Model description

The grid size of the geo-model is 100*40m, and the thickness of grid cell is about 0.1m. The total grid cell number of the geo-model is 262*236*216=13,355,712. For simulation, there are too many cells and a lot of CPU time will be needed. To save time and guarantee the reliability, a reasonable geo-model upscaling (only in z direction) has been done.

The geo-model has 216 layers, and after upscaling, the number of layers changes to 24 (Figure 1: Porosity and Permeability Models). Thus the number of grid cells decreases to 262*636*24=3,999,168 from 13,355,712, and the active cell number in the simulation is 1,188,816 for Khasib. In the up-scaled model, all the zones have been kept, including the high-perm layer Kh2-1-2L.
The K2 reservoir is a stratified anticlinal porous carbonate oil reservoir with edge and bottom water. In this study, this model has a total of 360 horizontal wells, 112 wells are water injector wells, 248 wells are oil producer wells the initial reservoir pressure for this model is 4270.78 psi. The field model and reserves will not be disclosed for confidentiality purposes and the investigation period is 15 years. Eclipse was the reservoir simulator with total in this step, the formation geometry is modeled as accurately as possible. Available data for interpreted horizons include seismic interpretation result in depth domain and horizon tops at well locations. Structure framework was generated with horizon data of Kh2 and the related well tops data. Constrained by the top of Kh2a, top structure of Kh1, Kh2b, Kh3 and Kh4 are then built. All horizons were honored and corrected to condition the well tops.

As an integral part of the Development Planning, optimum plan should be based on the results of dynamic simulation. Since water flooding is the main development mode, simulation grids have to be relatively fine to simulate water flooding in the carbonate reservoir.

As a comparison to the actual model, the sector model was developed based on full field model. The simple model has 1 injector well (I) and 1 producer well (P). In this model. The sector model has the same Petrophysics, PVT, and SCAL Properties of the full field model. The full field model was extensively studied in term of well placement since the improper placement of wells will definitely lower areal sweeping efficiency even in the absence of detrimental reservoir heterogeneities (2).

**Oil PVT Data**

Khasib reservoir crude in block AD4 appears different than Khasib reservoir crude in blocks AD1 and AD2. The AD4 Khasib crude is lighter and more gaseous than that found in the other blocks. Stock tank gravity from flash experiments is 30.45 API from AD4-15-3H and 31.14 API from AD4 original samples. By contrast, stock tank gravity from flash experiments is 26.53° API from AD1-9-4H and 25.97° API from AD2-12 -2H PVT data alone indicates a separate trend for block AD4. This adds to the body of evidence that AD4 be geologically different. The oil in reservoir is characterized by the following points:

1. Medium-heavy oil density, API ranging 22.5-31.14.
2. Bubble point pressure P_b 3030psi, lower than initial formation pressure (P_i), indicating the reservoir is unsaturated;
(3) Low viscosity at reservoir condition, being 1.543-3.795 mPa·s
(4) FVF being 1.26-1.40;
(5) GOR range of 398-877 scf/stb, which indicates energy of dissolved gas drive is considerable at the early stage of oil recovery; and
(6) Sulfur content being of 3.1-3.9%.

The oil in reservoir PVT model was modeled with PVTi software.

Reservoir Rock Properties

Kh2 core porosity ranges from 11% to 30%. The average is 24%. The porosity is normal in its distribution. The most common values range from 24%-26%. Core permeability ranges from 0.2 mD to 1042 mD, and the average is 18.5 mD. The permeability values are lognormal in distribution the most common sample value ranges from 1-10 mD. In general, the Kh2 reservoir is characterized by high porosity and moderate to low permeability.

The rock type of Kh2 is a complex assemblage of rocks with different pores, pore geometry, and pore throat size. The relationship between porosity and permeability from core analysis data shows four (4) orders of magnitude of permeability values, from 0.01 to 1 Darcy, over a porosity range of approximately 10 to 30 percent (Figure 2: Log-Log Permeability -Porosity relationship). Permeability models are derived from regression of core permeability versus porosity for each rock.

![Figure 2: Log-Log Permeability -Porosity relationship](image)

In Khasib formation, the permeability changes greatly for upper, middle and lower parts of Kh2. This is because of the lithology change in different parts in this formation.

As part of the previous effort, wettability measurements were performed on 47 samples from wells AD-08, AD-12, AD-13 and AD-15. Six samples were reported as oil-wet and remaining 41 samples...
were classified as water-wet. In relevant reports no information were given regarding sample condition such as fresh or aged samples.

**Polymer Solution Concentration**

Polymer adsorption is a strong function of polymer concentration. Extra of polymer concentration rises the viscosity of the polymer solution and the thick solution produces high likelihoods for polymer to adsorb (3). There are a total of six cases run in this study concerning the polymer solution concentration. For Case 1, polymer concentration is set to 0.0 lb/bbl. which means there is no polymer concentration, only water is injected into the wells. For rest of Cases (2, 3, 4, 5, and 6) the polymer concentration is set to (3, 5, 7, 10, and 12 lb/bbl) respectively. The results for the produced water presented in (Figure 3).

![Figure 3 Water produced Percentage for the six cases.](image)

From the results above, Unfavorable mobility ratio allows injected fluid to significantly bypass the residual oil. The bypass causes the injected fluids to flow in finger like structure and this flow is known as fingering effect (4) as seen in the (Figure 3) the (blue curve) represent the zero polymer concentration or fresh water injection only the water cut is about 60% after 15 years. Polymer flooding proves that the addition of polymer concentration will reduce the water cut and add additional recovery up to a certain level when the recovery factor of concentration (10,12) lb/Bbl are almost identical to each other. As seen (Figure 4). So selecting optimum concentration of 10 lb/bbl since the recovery factor is the same with case 6 and to reduce the cost of the additional polymer required for case (6),
It is significant that there is a limit for optimum polymer concentration. If the concentration is too high, polymer flooding will be ineffective. This is due to some reasons. The first reason is as polymer concentration increases, polymer solution viscosity will increase as well. So as polymer solution viscosity increases, it cannot navigate effectively through pores and it takes a longer time to sweep the oil. If the oil moving to producer well is faster than polymer moving from injection well, this will make polymer flooding not efficient. The second reason is as polymer concentration increases, it will create higher well injection bottom-hole pressure in injector well that will restrict polymer injection rate. So to counter that problem, for each of these cases, polymer injection rate is different as to make sure well bottom-hole pressure does not exceed the reservoir fracture pressure Hence the average reservoir pressure cannot be well maintained when injecting with higher polymer concentration solution. This will lead to uncreative polymer flooding.

**Polymer Solution Viscosity**

Once the polymer concentration is optimized in the previous section, the next step is to set the polymer solution viscosity ($\mu$). There are four set of polymer viscosity are used in this study. Polymer solution viscosity function has been changed from (30, 40, 50, and 60). The sensitivity was applied on Corresponding factor by which the water viscosity has to be multiplied to give the viscosity of the solution. This is to see the effect of polymer solution viscosity on oil recovery more clearly, as very close polymer viscosity factor will not give a clear result.
Figure 5 Water produced sensitivity for the change in polymer solution viscosity

From Figure 5, it shows that increment in polymer solution viscosity above 60 increases the water cut but when the viscosity factor set on (30) we get a close point for water cut of factor equal to 60, yes in polymer solution viscosity doesn't affect much on the total oil production (refer to Figure 6 Recovery factor for the sensitivity of polymer viscosity). Whereas changes in polymer solution viscosity will greatly affect the well bottom-hole pressure, as the higher viscosity solution needs more energy to move. In order to supply more energy for high viscosity solution to move, higher injection rate must be applied, and this will result in rapid increment of the well bottom-hole pressure.

Finally, the optimum solution viscosity factor is 30 as it results the reliable oil sweep efficiency.

Figure 6 Recovery factor for the sensitivity of polymer viscosity

Polymer injectivity rate and Timing

Polymer-solution injectivity rate is a substantial consideration for several reasons. First, the rate at which the polymer solution can be injected directly influences the economics of a polymer-flood plan.
Second, repetitive injection well cleanup jobs may be required if polymer or polymer-micro gel damages the near wellbore formation. These cleanup jobs can detract from the polymer flood’s economics and effectiveness. Injectivity index decreases as polymer molecular weight (MW) increases. Polymer-solution injectivity is more favorable when the polymer solution has a shear-thinning viscosity behavior. From (Figure 7) logically when we inject more fluid we get more water produced along with more Oil so we are unable to select the optimum rate from this figure since the injection BHP is also increasing see (Figure 8 Injection Pressure Vs Time).

![Figure 7 Injection rate Vs water cut](image)

Polymers tend to adsorb on the rock source even clog the injector/producer wells if the concentration is high. Adsorption decreases the permeability of the rock which can be of disadvantage in oil recovery. In high Injection rate 1750 or 2000 BblW/d the bottom hole injection pressure is rising giving an indicate that a resistance to the flow is exist as seen in Figure 8 Injection Pressure Vs Time from this figure we may choose to maintain the water injection rate around 1500 Bblw/D since the pressure is kept in the required range.

In case of no polymer injected, water starts to come out after two years from the first oil production. Another sensitivity was carried out to candidate the exact timing for the polymer injection. the simulation study shows that after two years the field must turn to polymer flooding otherwise the water will bearing the porous area around the producers wells.
Types of Polymer for EOR

Polymers are long chain organic molecules prepared from union of small molecules called monomers. They are flexible with high molecular weight ranging from $2 \times 10^6$ to $21 \times 10^6$ g/mole (5). Two types of polymers mostly used for Enhancing Oil Recovery (EOR) are Polyacrylamide (PAM), in its partially hydrolyzed form (HPAM) and Xanthan (6). In addition to water solvable acrylic polymer has been developed for use as a mobility regulator agent in enhanced oil recovery. (7).

Feasibility of Project

The project is planned and scheduled to be done in a period of at most 12 months. The approach that the author used is by using Eclipse shlumberger simulator to determine the oil recovery for each case and set of circumstances. The investigation involves around the improvement on mobility ratio by increasing the viscosity of displacing fluid, i.e. water, by addition of polymers, at an amount that are to be determined, type of polymers that will be used is Xanthan.

The main advantage of Xanthan polymer in EOR is that it is less sensitive to brine salinity and hardness in comparison to HPAM. Also it have greater effect to reduce the heterogeneity of reservoir due to the adsorption of the molecules on the surface (8).

In addition, the injection rate of these polymers will also be determined to give the highest recovery of oil.

Economically, Economic analysis shows the effectiveness of polymer flooding the price of Xanthan is about 4 USD per Kilogram (include transportation) as long as we are injecting concentration of 10 lb/bbl

So: $10 \text{ lb} = 4.5 \text{ Kg}$

$4.5 \times 4 \text{ USD} = 18 \text{ USD}$ for each barrel of water injected.
Adding 10 USD for the cost of oil processing = 28 USD

Based on oil price 50 USD then the revenue=50-28=22 USD Positive profit even with voidage replacement equal to (1) the project is economically viable.

2. Conclusions

This project addresses two main questions for polymer flooding. First, what polymer solution concentration should be injected? A base-case reservoir-engineering method is present for making that decision, which focuses on polymer concentration that bring the ultimate oil recovery and found to be 10 lb/bbl and the viscosity contrast of the solution with different type of polymers.

The second question is: when should polymer injection be stopped or reduced? For existing polymer floods, this question is particularly relevant in the current low oil-price environment. Should these projects be switched to water injection immediately? Logic given to support the choice from injectivity rate sensitivity the optimum rate is 1500 STB/d for the injector well and to start the polymer flooding after two years from field production first oil production.

3. Abbreviations and nomenclatures

| Abbreviation | Definition |
|--------------|------------|
| Bblw/D       | barrel water/day |
| Bbl          | barrel       |
| BHP          | Bottom hole pressure |
| Lb           | Pound        |
| EOR          | Enhanced Oil Recovery. |
| HPAM         | hydrolyzed Polyacrylamide |
| OIIP         | Oil Initially In Place. |
| IFT          | Interfacial Tension. |
| M_w          | molecular weight |
| RF           | Recovery Factor. |
| USD          | United states Dollars |
| STB/d        | Stock tank barrel/ day |
| (µ)          | Polymer solution Viscosity. |

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