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Effect of Polymer Flooding on Oil Recovery Using Reservoir Simulation, Umm-Faroud Field, Sirt Basin, Libya

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ABSTRACT

This work uses Polymer flooding as an Enhanced Oil Recovery (EOR) technique to increase the injected water viscosity to reduce the mobility ratio and improve sweep efficiency. A reservoir model was constructed using the reservoir-simulating method with Computer Modeling Group software (CMGs IMEX) to predict the oil production and water cut from Umm Foroud field, Sirt Basin, Libya. The models are based on data collected from 17 wells from the Umm Foroud field. Off which, five wells were utilized to build the models, while the other 12 wells were used to validate them. Three scenarios were made; the first was used to predict oil recovery with water injection only, with no polymer, the second model to predict oil recovery with polymer flooding of 10% concentration, and the third with polymer flooding of 20% concentration. The viscosity of water increased by two different concentrations of polymers. Results showed that when water viscosity increased, a significant reduction in mobility ratio occurred and hence, the sweep efficiency was improved. Oil production was improved (increased) in the second and third scenarios where the polymer-flooding scenario (10% and 20% polymer solution concentration) was used. However, the water cut was reduced when compared to water injection.

KEYWORDS: EOR, Polymer flooding, CMG software, water injection.

1. INTRODUCTION

In terms of oil recovery, Oil and gas fields can be divided into three distinct phases. Primary, Secondary, and Tertiary /enhanced oil recovery. In the primary stage, oil production from the reservoir occurs because of natural drive mechanisms. When the reservoir pressure is depleted to support the production from the reservoir, secondary oil recovery is applied. For maintaining reservoir pressure, water flooding is used because of its cost-effectiveness and availability of water. Problems such as reservoir heterogeneity, well siting, well spacing, and unfavorable mobility ratio can cause low oil production rates. [1]

Enhanced Oil Recovery (EOR) techniques are expensive and complex; hence, it is recommended to employ EOR only after the primary and secondary oil recovery has been exhausted. In those cases, residual oil cannot be produced because it is uneconomical to extract the remaining oil. [2]

In the tertiary oil recovery stage, about 30-60% of the reservoir's original oil in place can be produced which is good enough compared to primary and secondary recovery stages.[3]

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There are many types of EOR such as chemical flooding, miscible gas flooding, thermal recovery and Microbial EOR [3].

Polymer flooding, alkaline flooding, and surfactant flooding are chemical flooding processes. Surfactants are injected into the reservoir followed by a polymer solution to recover the oil that remains in the reservoir, by reducing the mobility ratio between oil and water, which increases volumetric sweep efficiency. [4]

Surfactants are used to reduce interfacial tension between oil and water. There are many limitations to using chemical flooding such as chemical cost, adsorption and loss of these chemicals in reservoir rock. Chemicals can be injected into injection wells and oil production occurs in other production wells. [4]

The percentage of oil that can be recovered after reservoir depletion is known as the recovery factor. Thus, the oil recovery depends on the recovery factor. The recovery factor magnitude for an oil field depends on geological, physical and economic elements. Around 70% of the reserves remain in the reservoir [5]. Polymer flooding is a very efficient chemical enhanced oil recovery method and has been used since the 1960s. It is widely recognized for its cost-effectiveness and great success in improving oil production. Polymer solutions are used to increase the viscosity of the displacing water which in turn decreases the water/oil mobility ratio, thus oil displacement efficiency is improved [6]. Polymer

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flooding is also used to recover the residual oil effectively from the formation, about 30% of the oil in the reservoir. injection. Polymers are used with water to decrease its mobility by reducing water permeability and increasing its viscosity. [7]

Polymer flooding will not decrease the residual oil saturation, but it is still an efficient way to reach the remaining oil more quickly or/and more economically. [6]

Interfacial tension force between the displacing water phase and the displaced oil phase can be reduced by using surfactants. Wettability altering of the rock surface is also necessary to enhance oil recovery. Polymers are mixed with water and then continuously injected for a period of time. Once 30% of the pore volume has been treated, polymer injection ceases. This decision is usually based on achieving optimal displacement efficiency and reducing the costs associated with continuous polymer usage [7].

Screening criteria for polymer flooding

Salinity and concentration of divalent ions of injected water and reservoir fluids at reservoir temperatures affect the viscosity and stability of polymer solution. The selection of molecular weight is affected by the reservoir permeability range [7]. Table(1) illustrates some of the most important criteria for successful polymer flooding.

Table 1: Screening criteria for polymer flooding [7].

Reservoir temperature (°F)	**<200.**
Crude oil viscosity (cP)	**<200.**
Mobile oil saturation (%PV)	**>10.**
Water-to-oil ratio (WOR)	**<15 preferred**
Average reservoir permeability (mD)	**>20.Lithology Sandstone preferred.**

The reservoir properties of the field, such as mobility ratio, etc. should be discussed in detail before starting any polymer-flooding project.

Mobility ratio

Based on the study of Needham et al.[8], the mobility ratio can be defined as:

$$M= (K_w/\mu_w)/(K_o/\mu_o)\rightarrow M=(K_w\cdot\mu_o) /(K_o\cdot\mu_w)$$

Where: M is mobility ratio, μ_w is water viscosity, μ_o is oil viscosity, K_w is water-

relative permeability, K_o is oil relative permeability.

According to the equation of mobility ratio, displacement is improved when the ratio is equal to or less than one.

The volumetric sweep efficiency is not good for water flooding and the main problem is the fingering effect. However, during polymer flooding, sweep efficiency improves due to decreasing the effect of fingering when it is compared to water flooding as seen in Figure (1). [8]

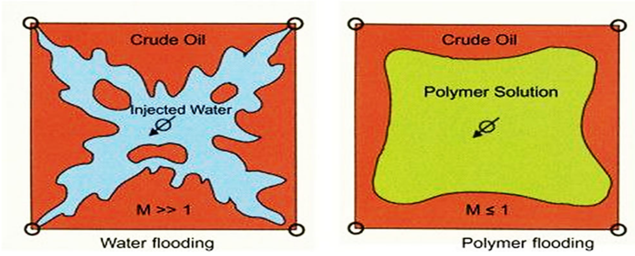

Figure 1: The effect of mobility ratio (The EOR Alliance).

Water Salinity:

According to previous studies, polymer adsorption is directly proportional to water salinity; it is desired to achieve sufficient quantity for adsorption. [9]

Types of polymers

Synthetic and Biopolymers are the two types of polymers that are usually considered in enhanced oil recovery.

Synthetic polymers

PAM (Polyacrylamide): it has a high molecular weight (>1× 106 g/mole). PAM is stable at high temperatures up to 92°C at normal salinity.

Hydrolyzed polyacrylamide is produced by hydrolysis of PAM. HPAM has many advantages. Among these are its cost-effectiveness and its resistance to both bacterial attack and mechanical forces that present during the injection of water. This type can also be used at temperatures up to 99°C. High sensitivity to the water salinity, hardness, and presence of surfactants or other chemicals are considered disadvantages of HPAM [9].

Biopolymers are formed by organisms; and given more hardness causing a good viscosity effect in saline water and a bad viscosity effect in freshwater [9].

Xanthan gum: A polysaccharide polymer produced by different types of bacteria through fermentation of fructose or glucose. This type of polymer is not sensitive to high salinity because it has high molecular weight and rigid chains. In the range of 70°C to 90°C Xanthan gum is considered thermally stable, and highly sensitive to bacterial degradation with low-temperature reservoirs. Furthermore, it may cause plugging. [9]

In this work PAM (Polyacrylamide), polymer flooding recovery method was used to regulate the mobility ratio of the injected fluid for better volumetric sweep efficiency.

2. METHODS

Reservoir simulation is a powerful and inexpensive tool, which can predict what is going on in the reservoir and the amount of production from substitute operations.

The simulator used in this paper is the IMEX black oil simulator in the Computer Model Group (CMG), which includes many options such as polymer flooding and dual porosity.

"CMG offers a reservoir engineering tool CMOST which can make history matching, sensitivity analysis and optimization of reservoir models" [10].

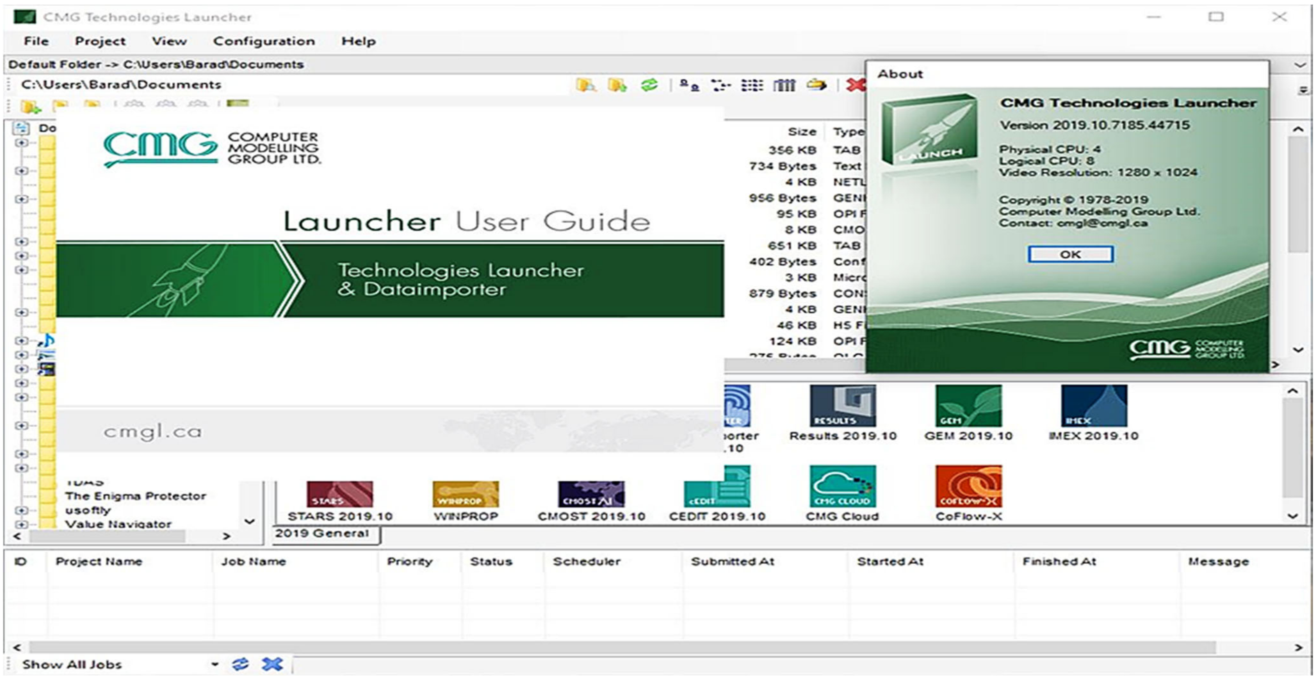

Figure 2: CMG software [10].

The main steps for model construction are as following:

1. Input reservoir data in CMG software,
2. Model building,
3. Estimate the best recovery factor using polymer flooding,
4. Model Verification
5. and Result dissection.

2.1 Case Study

"Umm-Faroud is a Libyan oil field located in Sirte Basin as shown in Figure (3) it was discovered by drilling well A- 1 in 1962.

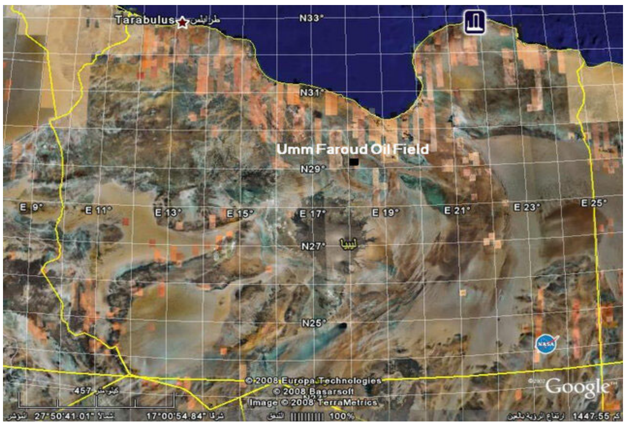

Figure 3: Umm-Faroud Oil Field Location.

17 wells have been drilled in the field until December 1995, (eight oil producers, six water injectors and 3 water sources). Three production formations, namely Bucharma "B1", "B2" and Dahra "B", successively at sub-sea depths of 1850 ft, 1900 ft and 2200 ft. Oil production was from Dahra "B" formation from six oil production wells (A01, A04, A06, A07, A10 and A14) at the rate of 6000 BOPD, reached 14,000 BOPD in early 1966 then declined rapidly due to a drop in reservoir pressure and increasing water cut. According to laboratory data, the field is an under-saturated oil reservoir; the bottom aquifer does not provide adequate pressure support to the reservoir due to formation tightness. The main production mechanism is rock and fluid expansion [11].

2.2 Model Description

The model was built using CMG simulator, based on the data collected from the Umm-Faroud field, such as thickness, petrophysical parameters (porosity and permeability), PVT properties, permeability saturation data, capillary pressure saturation data, initial pressure and saturation, well locations, and aquifer model design data. In addition, some experimental report's data such as relative permeability, bubble point pressure and saturations.

Input Data for CMG Software:

Three-dimensional model with five wells field units 35X35X8 Cartesian grid with 9800 grid cells.

The input data are shown in Table (2)

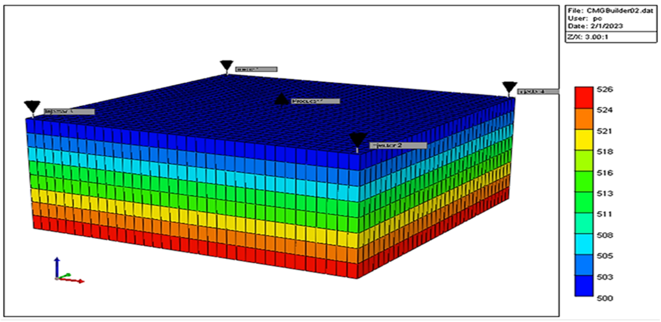

Figure 4: Reservoir grids form CMG software.

Table 2: Reservoir Data for the Model

Property	Value
Original Reservoir Pressure	1003 psi
Datum Depth	2210 ft ss
Saturation Pressure	253 psi
Oil Gravity	47 API@60 F
Reservoir Temperature	136 F
Viscosity Of Crude @ $P_{sat.}$	0.68 CP
Viscosity Of Gas @ $P_{sat.}$	0.0103 cp
Viscosity Of Crude @ $P_{initial}$	0.72cp
Viscosity Of Gas @ $P_{sat.}$	0.0135 cp
Hydrogen Sulfide	Positive
FVF Water @ 1000 p sia.	1.016
Water Viscosity	0.48 cp
Formation Water Salinity	57,000 ppm

Table 3: Represented data in CMG software.

Property	Value
Grid dimension	35*35*8
Water density	62.4 lb./cuft
Gas density	17.3 lb./CF
Water compressibility	3.3*10-6 psi -1
Rock compressibility	5*10-6 psi -1
Water formation volume factor	1
Water viscosity	0.48. cp
Separation condition (flash temperature and pressure)	60F 14.7 psi
Reservoir oil saturation pressure	253psi
Initial water saturation	0.44
Average porosity	19%
Average permeability	55md
Initial oil saturation	0.56
Reservoir rock type	Lime stone
Wellbore radius	0.25 ft.

2.3 Reservoir Fluid Properties

This section deals with fluids filling the reservoir rocks. Oil, gas and formation water properties are covered under pressure- volume -temperature section PVT, the black oil model is the most common where the oil properties, such as formation volume factor Bo, solution gas oil ratio R_s and oil viscosity.

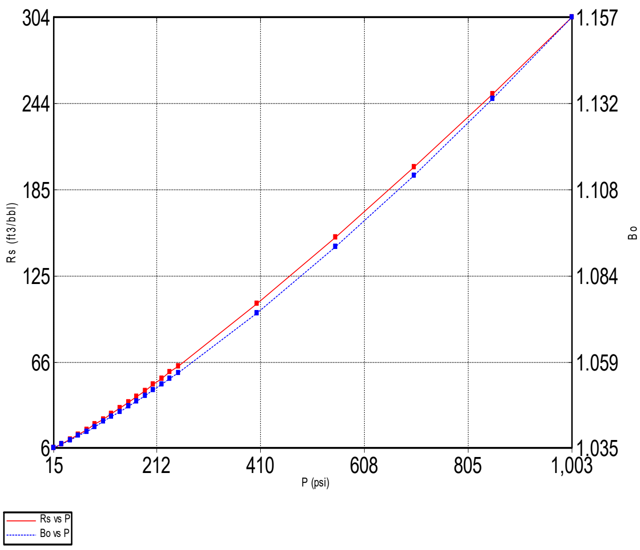

Figure 5: Bo and Rs with pressure.

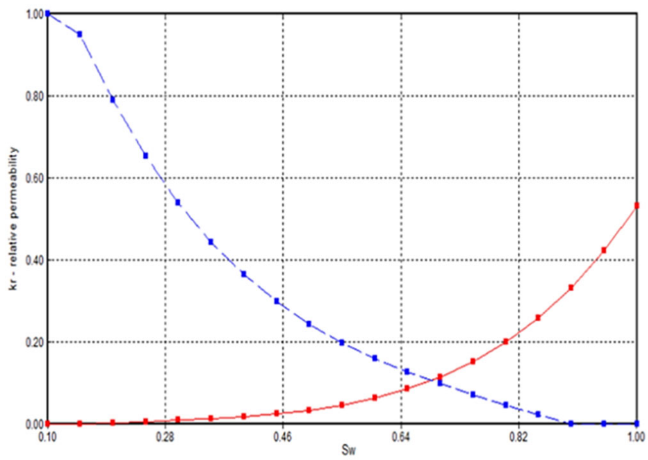

Figure 6: Relative permeability curves.

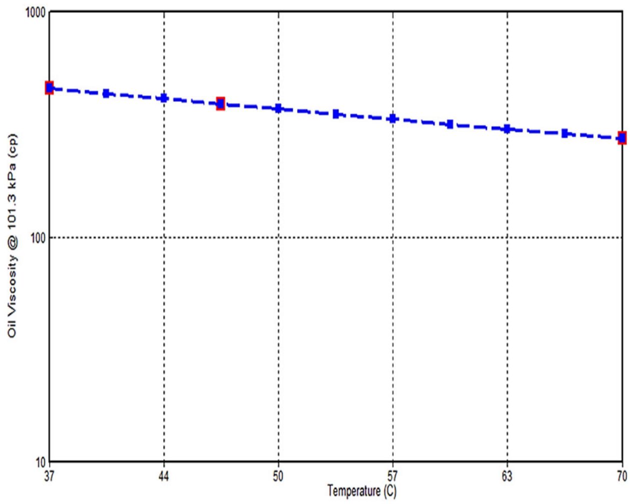

Figure 7: Oil viscosity with temperature curve.

2.4 Sensitivity Analysis:

The sensitivity analysis was run using different parameters to predict the best scenario of economic water injection and polymer flooding to achieve the highest oil recovery factor.

2.5 Well Specifications:

In this part, the constrain of the wells can be controlled and apply the design character of the water injection, Bottom hole pressure, and Surface water rate. The production period remained constant for all the scenarios for almost 5 years (2003-2008).

3. RESULTS AND DISCUSSION

In the first case, water injection was supposed without using a polymer solution. The result shows a reduction in the oil rate and an increase in water cut, the main reason is the difference in viscosity of injected water and remaining oil and its effect on mobility ratio.

There was an improvement in the oil rate and a reduction in water production after using 10% of the polymer solution (second scenario) with the injected water.

The third scenario, (with 20% of polymer) shows a higher oil rate and the recovery factor reaches 7.8%.

When 20% of the polymer solution was used there was a slight improvement in the oil production rate because of the low viscosity of the oil.

It is recommended to use a polymer flooding process to increase sweep efficiency in the water injection method and achieve high recovery factor in oil reservoirs.

3.1 Case (1) water injection without polymer.

In this scenario, water injection without using polymer was supposed; Figure (8) illustrates the oil production rate. Water cut was high as seen in Figure (9) Figure (10) illustrates the cumulative oil production for water injection without polymer.

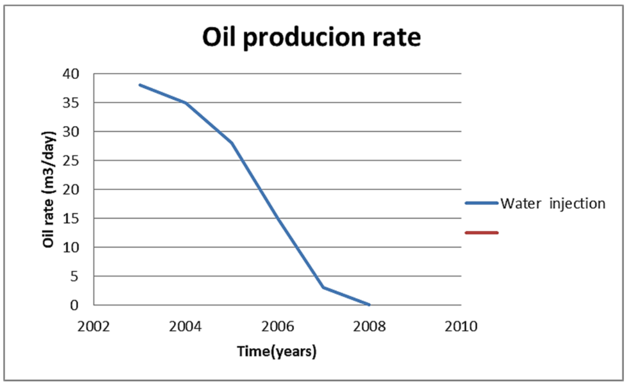

Figure 8: oil rate curve for case (1).

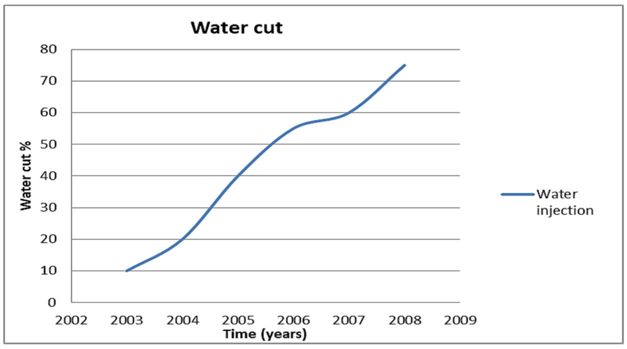

Figure 9: water cut curve for case (1).

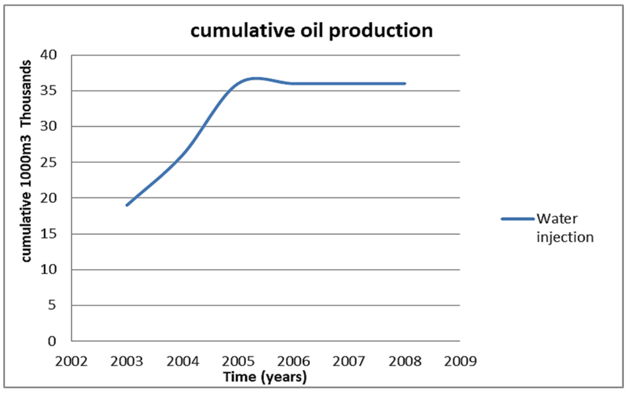

Figure 10: cumulative oil curve for case (1).

3.2 Case (2)

In this case, water injection was supposed with 10% of polymer concentration in Injection wells.

Figure (11) illustrates the oil rate. It indicates that there is an improvement in the oil rate after using 10% polymer concentration, and a reduction in water cut as seen in Figure (12). Figure (13) illustrates the cumulative oil production for polymer flooding with 10% concentration.

When compared to the first case, the improvement is clear, as shown in Figure (14) and Figure (15).

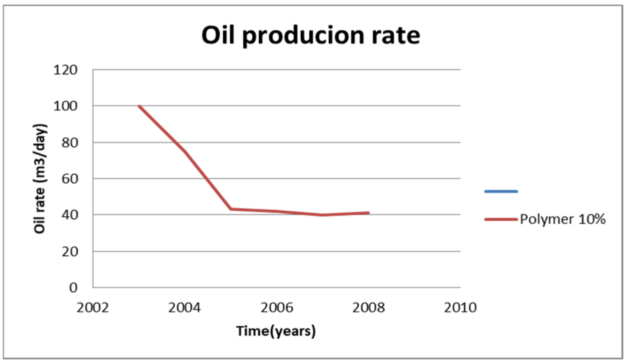

Figure 11: Oil rate curve for case (2), (with 10% of polymer).

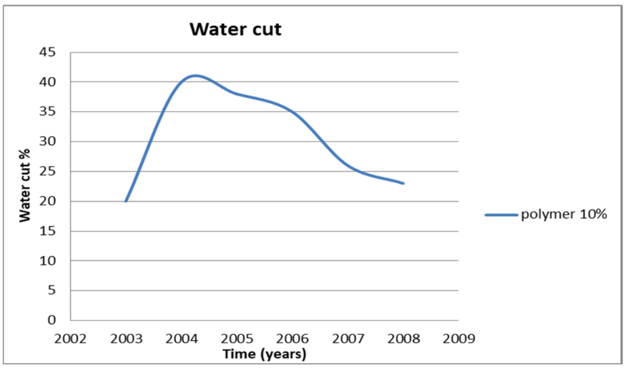

Figure 12: Water cut curve case (2), (with 10% of polymer).

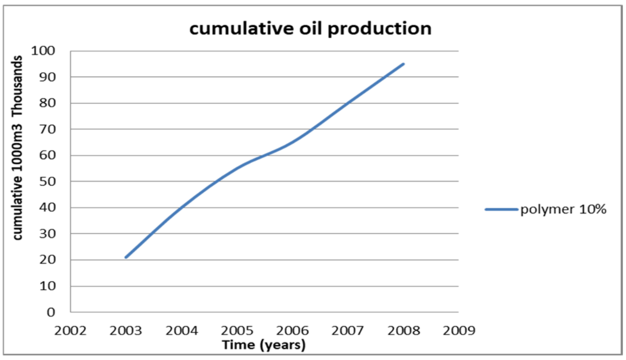

Figure 13: Cumulative Oil rate curve for case (2).

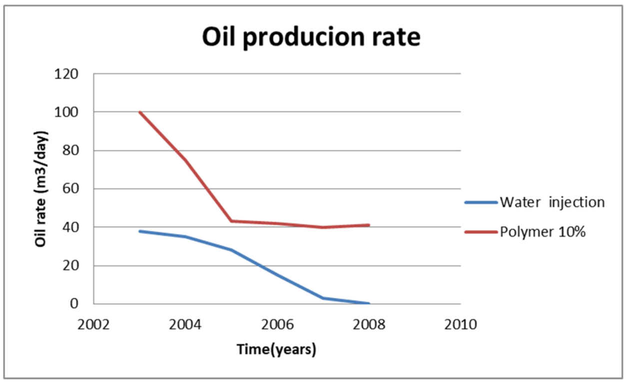

Figure 14: Oil rate curve for case (1) and (2).

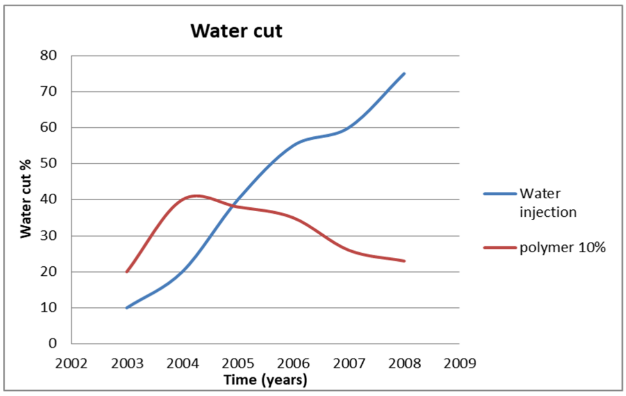

Figure 15: water cut curve case (1) and case (2).

Case (3)

In this case, 20% polymer concentration was supposed instead of 10% concentration.

Figure (16) illustrates the oil rate; there is more improvement in the oil rate after using 20% of polymer concentration, also water cut was slightly reduced, and the cumulative oil was increased as shown in Figure (17) and Figure (18) respectively.

Figure (19) illustrates the difference in oil rate between the second case and third case.

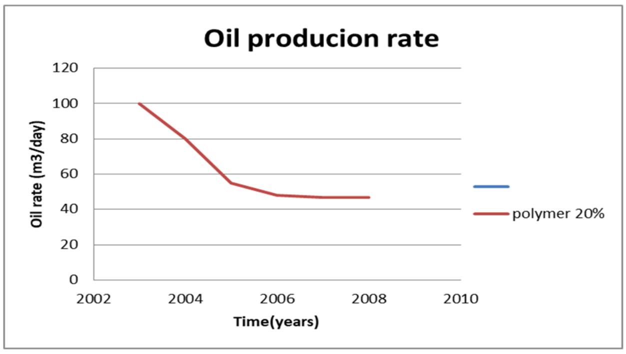

Figure 16: oil rate curve for case (3), with 20% of polymer.

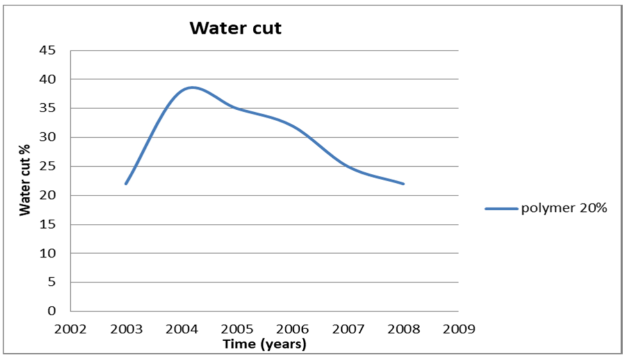

Figure 17: Water cut curve from case (3), with 20% of polymer.

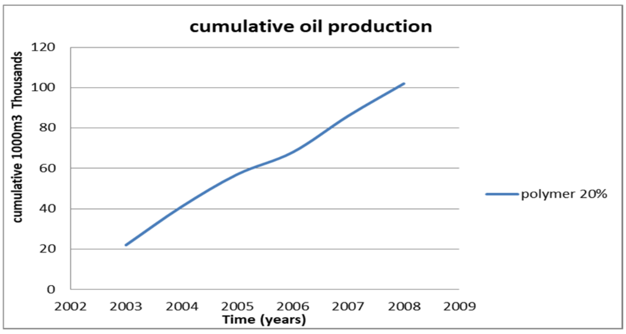

Figure 18: Cumulative Oil curve for case (3).

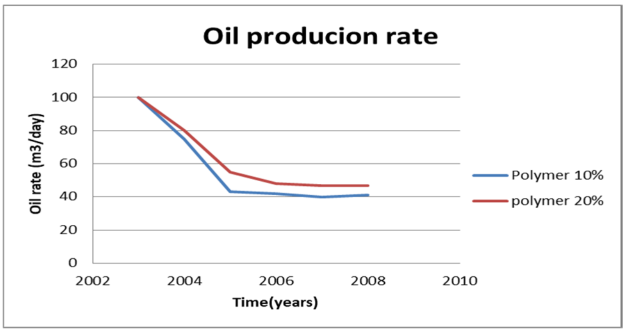

Figure 19: Oil rate curve for case (2) and case (3), from CMG software.

COMPARESION of RESULTS

After comparing the first scenario with the second and third scenarios, polymer with 20% concentration shows a better oil rate than using 10% of polymer concentration. However, no significant decrease in water cut as shown in Figure (20) and Figure (21).

In addition, the cumulative oil production was increased when the polymer was used (in 10% and 20% concentration) with increasing displacement efficiency and sweep efficiency, as seen in Figure (22)

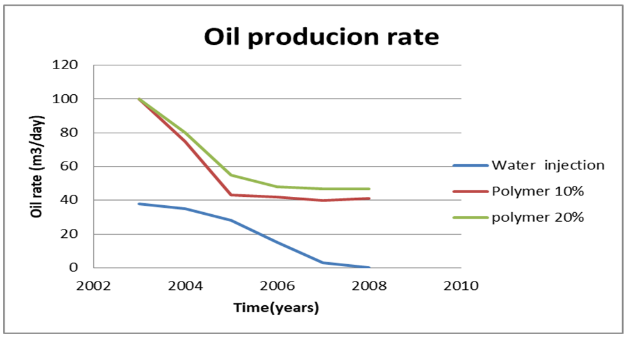

Figure 20: Oil rate curves for all cases.

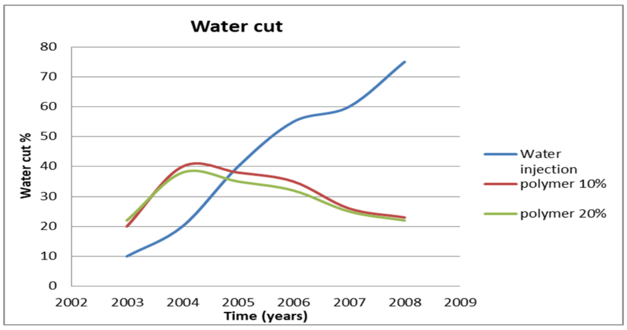

Figure 21: Water cut curves for all cases.

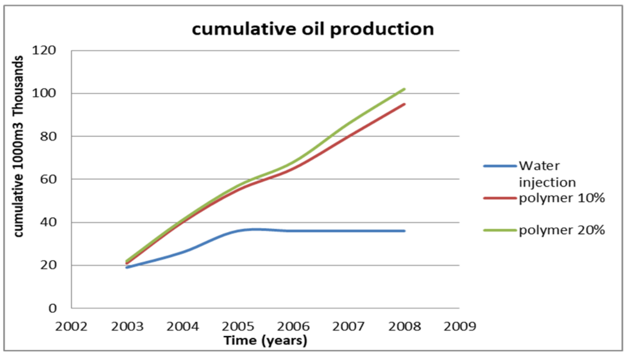

Figure 22: cumulative oil curves for all cases.

4. CONCLUSION

- This study has shown how polymer flooding is effective in oil recovery compared with water flooding.
- In the first scenario, where water injection without polymer was used in the injection wells. the liquid rate was low and there was no stability in the oil rate, gas oil ratio, and water cut was also high at the end of the water injection technique.
- In the second and third scenarios, polymer with 20% concentration shows a better oil rate than using 10% of polymer concentration. Good sweep efficiency can be achieved with a regular pattern with an optimal polymer concentration.

- There is many software available in companies and petroleum fields for use in sensitivity analysis techniques and drawing the required graphs such as OFM, Pipe Sim. and CMG. However, the most suitable software to be used for sensitivity analysis optimization is, (CMG) computer modeling group because it is very easy to use and highly useful reservoir simulation software.

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