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The Effect of Surfactant Polymer Concentration on the Distribution of Oil Drainage Area in Heterogeneous Reservoir

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Abstract
The use of chemical injection has been widely used in the oil field on a large scale. One of the enhanced oil recoveries (EOR) methods to increase production from old oil fields is through polymer surfactant injection, which functions to reduce interfacial tension and water-oil mobility ratio. This study focuses on developing a simulation model for chemical injection of polymer surfactant reservoirs by hypothetically making heterogeneous reservoir models in each layer with dimensions of 10x10x4. It consists of one a vertical well which is producer well located at the top of the left corner and one an injection well which is located at the bottom of right corner. This study shows a comparison between surfactant injection, polymer injection and SP injection using the same surfactant and polymer concentration with a concentration of 1000 ppm with 0.3 PV. Oil recovery in polymer injection turned out to be quite high compared to other chemical injections. In polymer injection, the oil recovery was 4.17%. Meanwhile, surfactant injection and SP injection increased by 0.59% and 0.61, respectively.

Keywords: Surfactant, Polymer, Injection, Recovery Factor

INTRODUCTION

The potential for oil reserves remaining in the reservoir after the conventional water injection process is still quite large. The remaining oil is left in the discontinuous phase in the form of oil droplets that are trapped or trapped due to capillary forces. The Enhanced Oil Recovery (EOR) method of surfactant-polymer injection has been proven to be effective in reducing the remaining oil saturation on an experimental scale in the laboratory and on a project scale in the field (Sheng 2014) by reducing the interfacial tension and mobility ratio between the oil and water phases The addition of these chemicals aims to change the physical properties of the reservoir fluid, with the main target being to reduce the interfacial tension, because if the interfacial tension has a large value then the mobility of oil in the reservoir will decrease. So that the oil recovery in the primary and secondary recovery stages will have an impact on the declining production rate.

In general, chemical injections are classified into three types, namely alkaline injection, polymer injection, and surfactant injection. Along with the development of research, a combination of polymer injection and surfactant injection was found which is better known as micellar-polymer flooding. In this case, micellar-polymer flooding has a higher recovery rate than the other three types of chemical injection. This chemical injection has good prospects in reservoirs that have been successfully injected with water or waterflooding (Abrams, A., 1988).

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The purpose of this research is to perform a hyphothetic model of reservoir using selected surfactants and polymers, then determine the injection scenario to obtain an optimal increase in oil recovery, and test the compatibility of surfactants and polymers before being applied in the field.

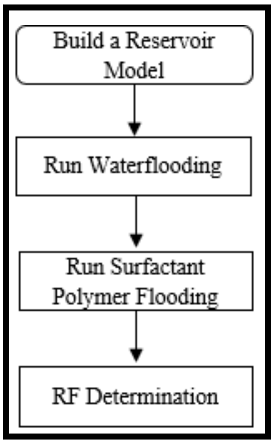

Figure 1. Flowchart

RESEARCH METHOD

The methodology of this research is shown in **Figure 1**. The first step is creating a hypothetical model of CMG STARS 2015. In this case, a reservoir model with heterogeneous layers will be created and followed by the first scenario of running waterflooding. At this stage the reservoir has not added any chemical injection. After that, the second scenario was carried out by doing surfactant flooding and seeing the changes in oil recovery. Furthermore, the third scenario is running where the reservoir is injected with polymer flooding to find out how much the oil RF changes. In the final scenario, SP injection will be carried out which will later be able to see clear differences between other scenarios. The results of this reservoir simulation will be compared between the amount of oil recovery before and after polymer surfactant injection. This experiment was conducted using surfactant-polymer injection after completion of the waterflooding (secondary recovery) stage.

DESCRIPTION OF RESERVOIR MODEL

A compositional reservoir simulator, STARS version 2015, by Computer Modelling Group, is applied to construct a reservoir model and investigate the performance of surfactant-polymer flooding. The reservoir model which represented a generic field with the number of grid is 10 x 10 x 4 (i, j, k). It consists of one a vertical well which is producer well located at the top of left corner dan one an injection well which located at the bottom of right corner.

The inherent assumption that there are no gas cap and bottom water drive, the heterogeneity by layer, not each by grid. The geo-mechanical effect such as dilation related to pressure and temperature are ignored in this model. Due to limited data, fluid and rock properties are assumed to be homogeneous in the whole reservoir.

The fluid component and rock properties are generated from the STARS default by using builder correlation. STARS generates fluid component data using Builder correlation to modify unwanted data for upscaling with high efficiency of running time. The fluid data include fluid properties in reservoir, endpoint scaling of the relative permeability curve, temperature dependent relative permeability curve and modifying relative permeability curve based on compositional dependence.

The model simulation has a porosity of 0.38, temperature of reservoir is 200 F and the pressure of 2600 psi. For further, Table 1 displays the reservoir model characteristic, and figure 2 shows the 3D model of visualization of the reservoir model.

Table 1. The Result of Measurement IFT of Surfactant

Reservoir Properties	Value
Grid Type	Cartesian
Grid System	Quick Pattern Grid
Grid Configuration (i x j x k)	10 x 10 x 4
Total Grid	400
Reservoir Pressure (psi)	2600
Reservoir Temperature (F)	200
Depth of Top Grid (ft)	2500
Porosity	0.38
Grid Thickness (ft) (Layer 1-4)	20 15 18 17
Permeability i (md) (Layer 1-4)	200 150 185 175
Permeability j (md) (Layer 1-4)	200 150 185 175
Permeability k (md) (Layer 1-4)	20 15 18.5 17.5
Swc	0.2
Sor	0.8
Oil Gravity (API)	20
Gas Gravity (lb/ft3)	0.0604786
Water Density (lb/ft3)	60.5489
Rock Compressibilty (1/psi)	5.7×10^{-7}
Water Factor volume Formation	1.03
Water Compressibility (1/psi)	2.64875E-07
Water Viscosity (cp)	0.319053

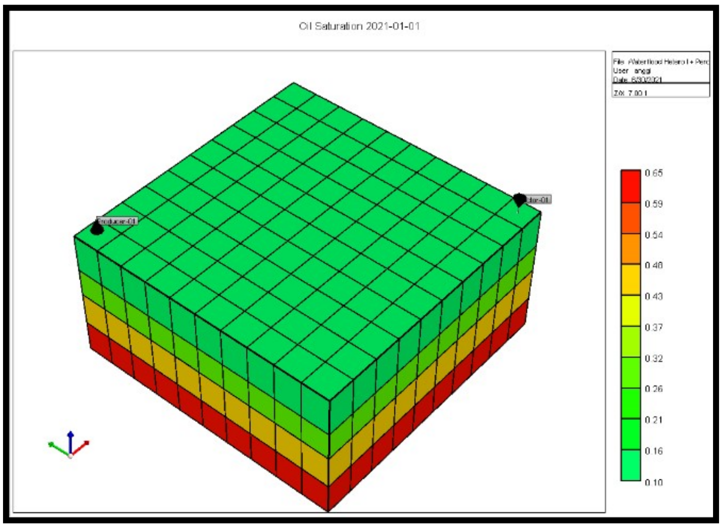

Figure 2. Schematic 3D View of the Model

To study the effect of improving oil recovery with the surfactant polymer flooding requires a simulator program. The model used the Cartesian grid with a quick pattern grid system. In this area, well spacing is about 400 blocks and run simulation for 10 years.

RESULT AND DISCUSSION

In the study of the coreflooding test in the surfactant-polymer injection laboratory that was previously carried out (Kristanto, D., et.al 2018), sample measurements were made of the IFT surfactant SS-B8020 and polymer rheology HYBOMAX 4785. In order to get maximum oil recovery, four scenarios have been employed. These are scenario 1 is waterflooding, scenario 2 is surfactant flooding, scenario 3 is polymer flooding, and scenario 4 is surfactant polymer flooding. Constraint used within the injection site well is the maximum injection rate of 1000 BWPD equivalent and Bottom Hole Pressure of 1800 psi. Simultaneously, the constraint used in production well is the maximum injection rate of 3000 BOPD equivalent.

A. Interfacial Tension Measurement Result

Surfactant SS-B8020 was dissolved in well formation water L5A-217 Block Q-22 with several variations of concentration. In addition, a temperature resistance test was also carried out and the results showed that the surfactant was not damaged at the reservoir temperature (104.4 ^{0}C). Figure 3 displays the graphic of IFT Surfactant, and Table 3 displays the result of measurement IFT of surfactant.

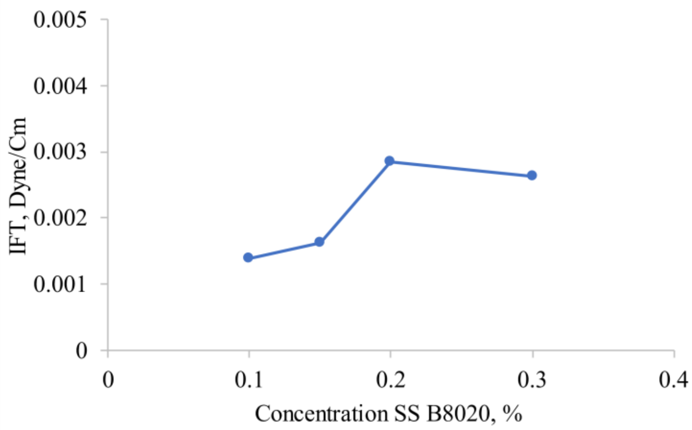

Figure 3. The result of measurement IFT of surfactant

Table 2. Interfacial Tension Measurement Result

Surfactant	Consentration (%)	Dilluting Water Block	Oil Sample	IFT (dyne/cm2)
SB-B8020	0.1	Q22/L 5A-217	TANK 02 SP VII	0.001381
				0.00123
				0.00113
SB-B8020	0.15			0.001621
				0.00167
				0.00164
SB-B8020	0.2			0.002852
				0.002761
				0.002815
SB-B8020	0.3			0.002628
				0.002578
				0.002308

B. Polymer Rheological Analysis Result

Figure 4 displays the graphic of rheological polymer result from 1000 ppm, 1100, ppm, 1200 ppm in 90°C and Table 4 displays the result of rheological polymer.

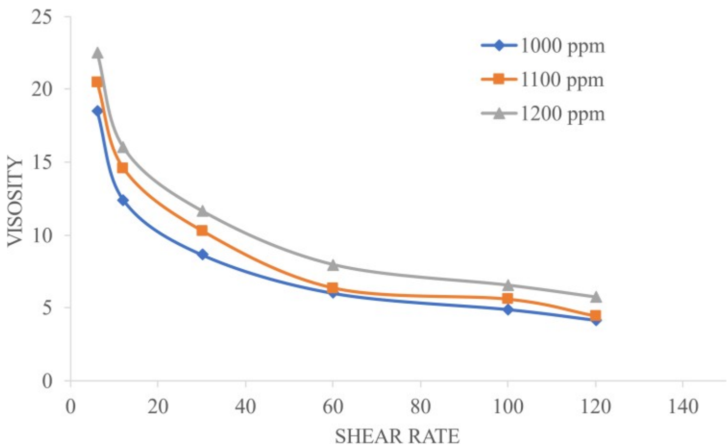

Figure 4. Polymer viscosity HYBOMAX 4785

Table 3. Polymer Rheology of HYBOMAX of 4785

RPM	Shear Rate (1/sec)	Temperature 90 °C	ppm
6	7.92	18.5	1000
12	15.8	12.4	
30	39.6	8.65	
60	79.2	6.02	
100	132	4.91	
120	158	4.18	
6	7.92	20.5	1100
12	15.8	14.6	
30	39.6	10.3	
60	79.2	6.37	
100	132	5.6	
120	158	4.44	
6	7.92	22.5	1200
12	15.8	16	
30	39.6	11.65	
60	79.2	7.97	
100	132	6.56	
120	158	5.75	

C. Result of Waterflooding

Scenario 1 is running the waterflooding stage. The waterflooding process is running in production well and injection well. Polymer surfactant injection has not been carried out. In this scenario, the waterflooding process is carried out for 10 years from 2021 to 2030. Figure 5 shows the initial conditions of the production flow rate, water cut and residual oil production. During the waterflooding period, chemical injection has not been added to the injection well. The purpose of waterflooding is to carry out preliminary flooding on the reservoir. The results obtained from scenario 1 are cumulative residual oil production (recovery factor) of 30.98%.

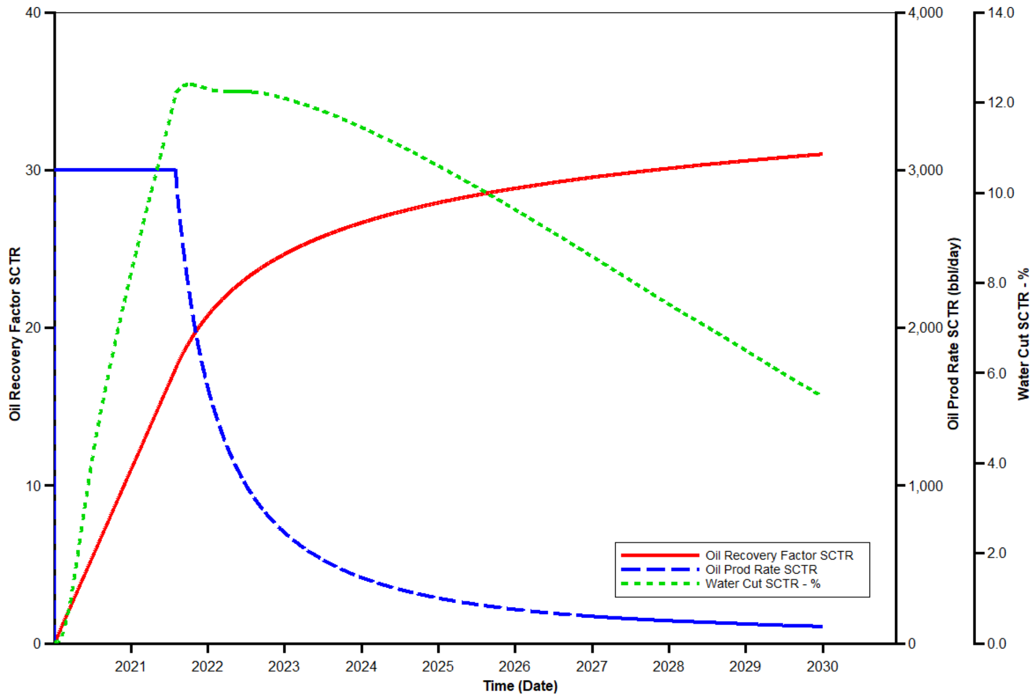

FIGURE 5. Production rate of waterflooding

Result of Surfactant Flooding

Result of Polymer Flooding

Scenario 3 is polymer flooding. Polymer injection was also carried out in the same year as the scenario 2. The sequence in this polymer injection stage is slug water injection, then polymer slug injection with a concentration of 0.3, second chase water injection, polymer slug injection with a concentration of 0.3, and slug water injection return. The polymer injection process is carried out in early 2023 until the end of 2023 and in early 2025 until the end of 2025 with a polymer concentration of 0.3% with 0.3 pore volume. When compared with the waterflooding stage, the addition of oil recovery occurred by 6.07% and when compared with surfactant injection there was an increase of 4.99%. The results from the addition of polymer injection have a fairly high increase compared to surfactant injection and waterflooding. It can be considered that the rock sweeping efficiency is efficient enough to reduce the residual oil in the rock and increase the oil recovery. The addition of a sufficiently low polymer concentration will reduce the clogging of the rock pores thereby improving the volumetric sweeping efficiency. The results obtained from scenario 3 are cumulative residual oil production (recovery factor) of 37.05%.

Result of Surfactant-Polymer Flooding

Scenario 4 is surfactant-polymer flooding. Polymer surfactant injection was also carried out in the same year as the previous scenario. In this scenario, surfactants and polymers will be injected into the reservoir rock in various stages. The first stage is preflush (water slug injection) in early 2020-2023. Furthermore, injection of surfactant slug with a concentration of 1000 ppm in early January 2024 until the end of December 2024. Then, the water was injected again as second chase water in early 2025 until the end of 2025. Then polymer injection was carried out with a concentration of 0.3% and 0.3 pore volume at the beginning of 2026 until the end of 2026. Then at the beginning of 2027 until the end of the scenario, it will be continued with water injection. The results of oil recovery at this stage have a significant increase of 10.25% from waterflooding. This increase occurs because the addition of the surfactant concentration injected into the reservoir will reduce the IFT between the oil and water phases so that it will increase the capillary number and increase the mobility of the trapped fluid and the addition of polymer with a low concentration makes the polymer molecules smaller so that it clogs the pores of the rock can be avoided. And the role of the polymer also acts as a pressure fluid which will reduce the mobility ratio (oil-water) so that it will improve the volumetric sweeping efficiency. The results obtained from scenario 3 are cumulative residual oil production (recovery factor) of 41.23%. Table 4 and Figure 4 show the results of the increase in oil recovery in each scenario.

Table 4.

Scenario	**OOIP**	**Additional**
	(%)	OOIP (%)
Waterflooding	30.98	-
WF + Surfactant Flooding	32.06	1.08
WF + Polymer Flooding	37.05	6.07
WF + SP Flooding	**41.23**	**10.25**

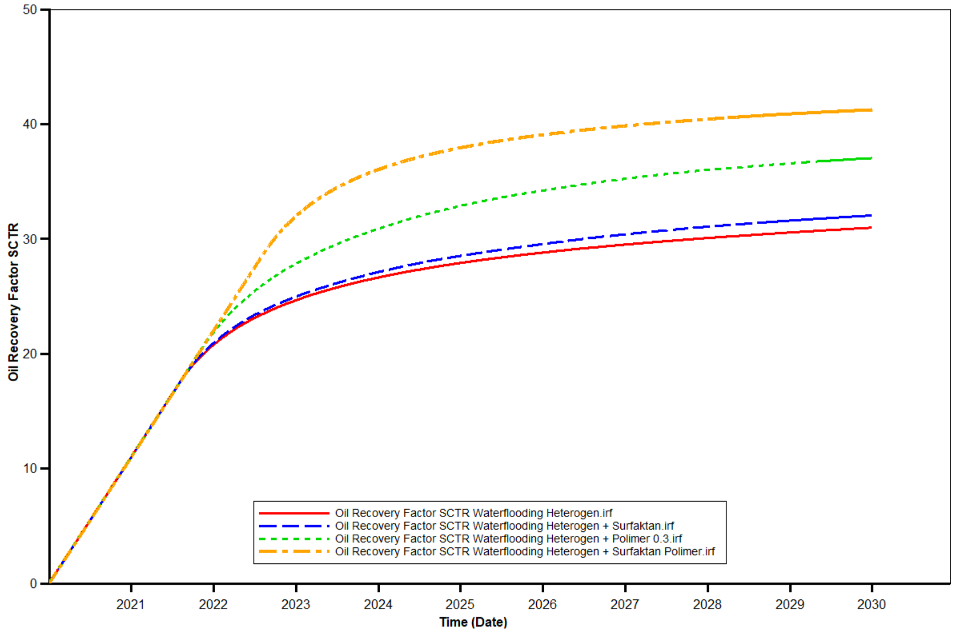

Figure 6. Recovery vs Time of Each Scenarios

CONCLUSION

In the present study a series of flooding experiments have been conducted to observe the additional oil recovery after water flooding using surfactant, polymer and surfactant-polymer slug. Based on the experimental results the following conclusion may be drawn such as first, surfactant-polymer flooding increased oil recovery by 10.25% OOIP compared to the surfactant flooding and polymer flooding by injecting same concentration SP slug. Second, the use of low polymer concentrations and high surfactant concentrations will result in substantial oil recovery. Third, the use of surfactant SS B8020 as a fluid injection does not cause blockage (plugging) in the pores of the reservoir rock.

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