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Investigation of Polymer Flood Performance in Light Oil Reservoir: Laboratory Case Study

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ABSTRACT - The use of polymer solutions in the application of chemical EOR injection technology has a role in increasing oil recovery efforts by improving oil mobility in porous media. The addition of the polymer solution is expected to increase the viscosity value of the displacement fluid so that it can form a “piston-like” effect to increase the volumetric sweep efficiency of the light oil reservoir. The polymer used in this study was HPAM using 3 concentrations, namely 500 ppm, 1000 ppm, and 1500 ppm conducted at a temperature of 70 °C. The rheology test of the polymer included concentration vs temperature and shear rate vs viscosity. Thermal stability testing of polymer for 7, 14, 30, 60, and 90 days at 70 °C was done to determine the stability of the polymer solution. Filtration testing was conducted with the criteria of FR <1.2. The static adsorption test has been done with the standard limit of adsorption value <400 μg / gr. Polymer injectivity test using 3 variations of injection rates and coreflooding test were conducted to determine the reduction of Sor in reservoirs due to polymer displacement. From the polymer testing stage, it was found that HPAM polymers at 3 concentrations were compatible with the injection. This is indicated with the clear solution for 3 concentrations at room temperature and 70 °C. The rheology test results showed that the polymer solution with 3 concentrations was decreased in viscosity with the addition of the shear rate value. In the thermal stability test, the viscosity value of the HPAM with 500 ppm was relatively constant. The value of the FR for HPAM 500 ppm is 1.1, HPAM 1000 ppm is 1.07 and HPAM 1500 ppm is 1.03. The results of the static adsorption test showed the lowest HPAM value of 500 ppm was 156 μg/gr. In the injectivity test results, the resistance residual factor (RRF) values at injection rates of 0.3, 0.6, and 1 cc/min were 0.8, 1.04, and 1.12. The RRF value was close to 1, indicating that after injection of 500 ppm of HPAM tended to not experience plugging. Polymer flooding shows the oil recovery factor (RF) of water injection is 39% OOIP, and RF after polymer injection with 0.35 PV with flush water is 13.5% OOIP or 22% Sor. Knowing the behavior of HPAM polymer with various concentrations to be used for chemical EOR injection, it could provide advantages for future implementation in the light oil reservoir in Indonesia.

Keywords: filtration, injectivity, light oil, polymer flooding, rheology.

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INTRODUCTION

The use of polymer solutions in the application of chemical EOR injection technology has a role in increasing oil recovery efforts by improving oil mobility in porous media. The addition of the polymer solution is expected to increase the viscosity value of the displacement fluid so that it can form a “piston-like” effect to increase the volumetric sweep efficiency of the light oil reservoir. (Sheng, 2010; Seright et al, 2008; Shah and Schechter, 1977; Jamaloei et al, 2011).

The polymer screening and performance testing must be done before pilot scale implementation in the oil fields. The partially hydrolyzed polyacrylamide (HPAM) polymer was used in this study. Several tests have to be passed to make sure the HPAM polymer performance in reservoir conditions meets the criteria which will improve the oil recovery of the mature fields. Several tests which must be done were screening tests or rheology evaluations such as compatibility tests, viscosity vs. shear rate tests, thermal stability tests, filtration tests, and static adsorption tests. The injectivity tests and coreflooding tests were also carried out to know the performance of the polymer injection into the native and/or synthetic core. The purpose of this study is to investigate the performance of the HPAM polymer injection in increasing oil recovery in the light oil reservoir.

METHODOLOGY

This research study begins to understand the rheological properties of the polymeric material and provides more insight into the adequacy of polymer HPAM from its behavior through porous media (reservoirs). HPAM concentrations of 500, 1000, and 1500 ppm were tested in this study.

The material of HPAM was mixed in brine water that has a designated salinity of roughly 2800 ppm (see Table 1 for brine water composition). The experiment consists of several tests, starting with testing compatibility, shear test, filtration, adsorption, thermal degradation, injectivity, and coreflooding (Poettman and Hause, 1978; Lemigas, 2008; Veerabhadrappa et al, 2011). All the tests were carried out at 70°C as the light oil reservoir temperature.

Table 1
Brine water composition

Parameter	Value	Unit
ANION		
Chloride	709.06	mg/L
Bicarbonate	1037.31	mg/L
Sulfate	0.07	mg/L
Carbonate	120.02	mg/L
Hydroxide	0.00	mg/L
KATION		
Sodium	891.1	mg/L
Calcium	20.04	mg/L
Magnesium	15.19	mg/L
Iron	0.00	mg/L
Barium	0.00	mg/L
Total Dissolve Solid	2792.81	mg/L
pH	8.71	

- Compatibility test

  The solubility of HPAM with various concentrations was visually observed at both room and 70 °C temperature to investigate the phase solution, color changing, and precipitation.

- Shear test

  All the rheological experiments were performed on Brookfield DVIII with UL adaptor. For each test (viscosity vs concentration and viscosity vs shear rate), the polymer solutions were prepared with varying concentrations. Concentrations ranged from 500 ppm to 1500 ppm of polymeric material in brine. The viscosity vs concentration of HPAM was measured using a shear rate of 7 rpm and the viscosity vs shear rate was measured using a shear rate from 50 rpm to 250 rpm.

- Filtration test

  A filtration test was conducted to evaluate whether the polymer solution has free of aggregates which could lead to formation plugging. The measurement of the filter test is pumped through a 3 µm membrane with a differential pressure of 2 bars.

- Adsorption test

  The polymer solutions were prepared to conduct a static adsorption test according to Recommended Practice (RP 63).

- Thermal degradation test

  Tests were performed for 3 months at 70 °C temperature under anaerobic conditions in sealed glass ampoules.

- Injectivity test

  HPAM injectivity test was run at a concentration of 500 ppm, the temperature of 70 °C, and slow injection rates of 0.3 cc/min, 0.6 cc/min, and 1 cc/min.

- Coreflooding test

  During the flooding experiment, the injection rate of the displacing fluids was controlled at 0.3 cc/min with polymer injection of 0.35 PV.

RESULTS AND DISCUSSION

Polymer flooding is intentionally conducted to reduce the relative permeability of water in the reservoir, therefore can improve the production of oil, as well as enlarge the swept volume of the reservoir. Recent popular material of polymer that is assured to accommodate oil fields is HPAM. HPAM has most often been used to achieve a more favorable mobility ratio and improve macroscopic sweep in chemical EOR by increasing the viscosity of the water. When dissolved in fluid, the polymer solutions have a viscosity that depends on many aspects: concentration, molecular weight, temperature, and salinity (LEMIGAS, 2008; Levitt and Pope, 2008).

In this study, the investigation of polymer flood has been performed using light crude oil. The characteristic of light crude oil has been shown in Table 2. Based on the result, the °API of crude oil was approaching 28 and this has to do with designing the compatible HPAM type. Besides, the water analysis demonstrates roughly 2800 ppm salinity brine.

Table 2
Characteristic of light crude oil

Determination	Method	Result	Unit
Density at 15◦C	ASTM D. 5002	0.8792	g/cm3
◦API Gravity	ASTM D. 5002	27.5588	-
Kin. Viscosity at 70◦C	ASTM D. 445	6.9884	cSt
Pour Point	ASTM S. 5853	45	◦C
Asphaltene	IP. 143	0.374	%wt
Total Acid Number	ASTM D. 664	0.0156	mg KOH
Saturated	Column Chromatography	52.20	%wt
Aromatic	Column Chromatography	16.04	%wt

The compatibility of the polymer solution was first conducted at both room and 70 °C temperatures. This presents in Figure 1, with the good result of the clear phase solution, the color of the solution was not changing, and no precipitation, which is essential to obtain distinctly sufficient chemicals.

The rheological properties of the HPAM polymer

Figure 1
Compatibility polymer solution at room temperature (a) and 70°C (b)

solution were evaluated by measuring the apparent viscosity vs concentration and viscosity vs shear rate. This experiment is one of the most prominent screenings of an injected chasing fluid during the chemical flooding process. Figure 2 demonstrates variation shear rate from 50 rpm to 250 rpm was conducted on the viscosity of 3 concentrations of the polymer at 70 °C temperature. This result presents HPAM is generally classified as a non-Newtonian fluid because the viscosity changes when the shear rate was applied. Thus, the type of fluid rheology is pseudo-plastic fluid. In this desired condition, pseudo-plastic fluid was known as shear thinning, in which viscosity decreases as the shear rate increases. The experiment result of viscosity vs concentration demonstrated the viscosity increasing steadily with increasing polymer concentration at 70 °C temperature. This behavior greatly contributes to the shear thickening of the HPAM solution when the polymer flows at a high shear rate in porous media.

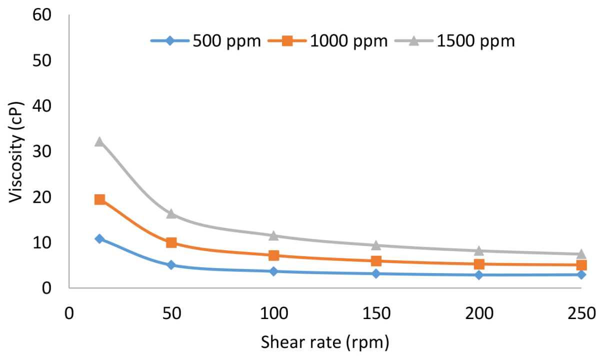

Figure 2
Effect of polymer on shear rate test results

The filtration test was performed to determine whether the polymer can flow through the rock pores and to evaluate the effect of debris. Figure 3 informs a volume plot graph against the time of the polymer with 3 concentrations. Each concentration solution ensured that polymer hydration had been achieved.

The value of the FR for HPAM 500 ppm is 1.1, HPAM 1000 ppm is 1.07, and HPAM 1500 ppm is 1.03. This result rapidly indicates HPAM is acceptable as it does not tend to plug porous media in the reservoir because the requirement of the filtration ratio (FR) value was below 1.2.

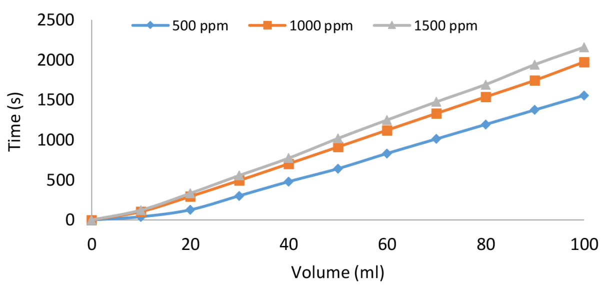

Figure 3
Filter test using 3 μm membrane results

Table 3
Core characteristic

Core	D (inch)	L (inch)	W (gr)	*Φ*	Ka (mD)
a	1.5	1.9	100.0	0.30	1302.1
b	1.5	1.8	98.3	0.27	1539.7
c	1.5	1.7	93.9	0.26	1493.4

The thermal degradation test was conducted for 3 months at 70 °C temperature to investigate the remaining viscosity of HPAM. The result is presented in Figure 4. The viscosity of 500 ppm maintains a constant value in the last 30 days, and the rest after 3 months of the aging period, decreases slowly from 10 cP to 7 cP with a viscosity retention percentage of 30%. Comparatively, the remaining viscosity of the two concentrations left was demonstrated at 1000 ppm and 1500 ppm with increasing the number viscosity due to the changing of the colloidal system solution, likely through a hydrolysis reaction. Thus, more effective preparations should be developed to improve their thermal degradation.

To understand the performance of the polymer to the rocks, injectivity and coreflooding tests were carried out. The characteristic of the rocks that were used is sandstone native core plugs with a permeability range of 1500 to 2500 mD and an average porosity of 0.26.

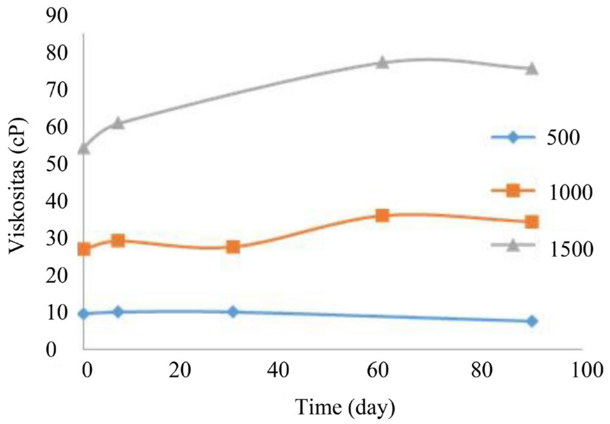

Figure 4
Thermal degradation test results

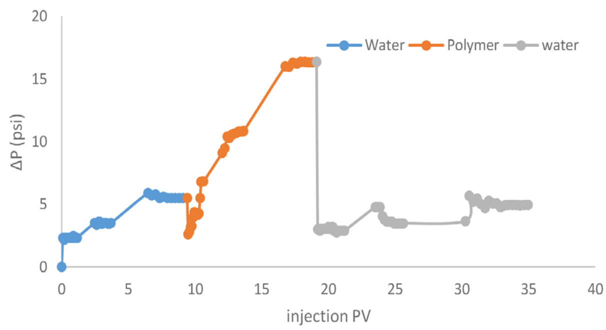

Figure 5
Injectivity test results

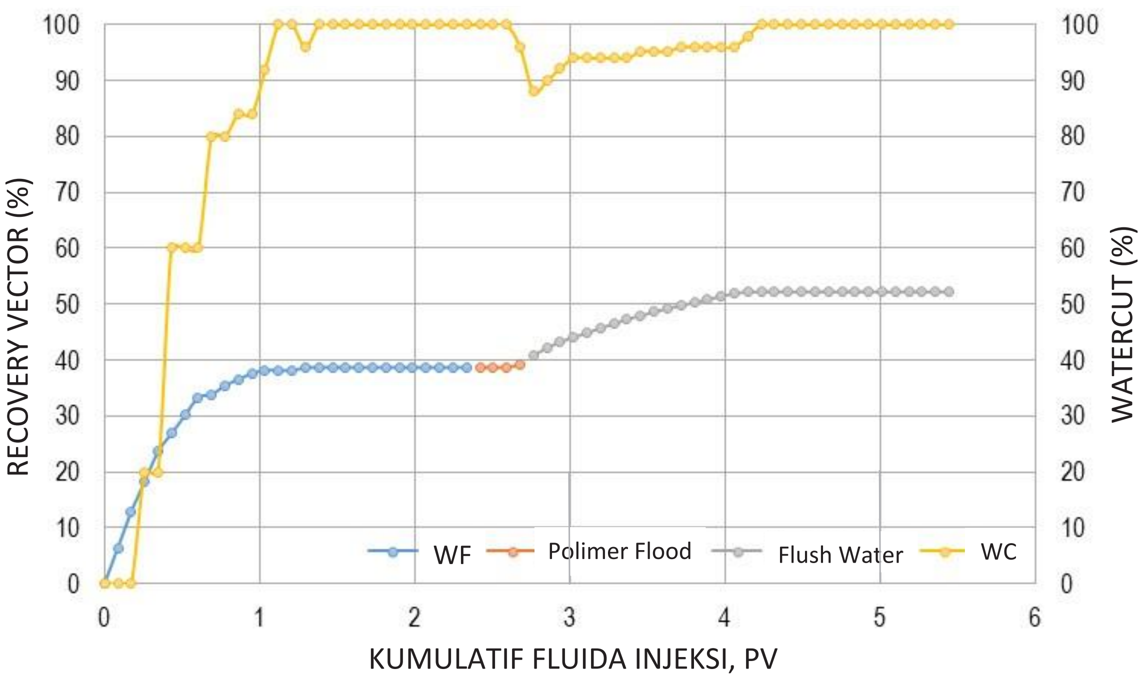

Figure 6
Coreflooding test results

The injectivity tests were carried out using a step-up rate of 0.3, 0.6, and 1 cc/min for every concentration of polymer solution. The core used in the injectivity and coreflood test could be seen in Table 3. The results of the polymer injectivity can be seen in Figure 5. From the test results, the polymer has a Residual Resistance Factor (RRF) value near 1 (one) which means that the permeability of the core plugs after polymer injection were not changing as much and also indicates plugging did not happen after the polymer injection.

From coreflooding test result, recovery factor (RF) after waterflood is at 7.2 cc or 38.7 % (OOIP), and Sor after waterflood is at 11.4 cc (61.3% OOIP). With injecting 0.35 PV polymer, recovery of oil is at 2.4 cc or 13% OOIP. This result shows that by injecting polymer after waterflood, additional oil recovery can be gained at about 13.5% OOIP or about 22% ROIP (see Figure 6).

CONCLUSIONS

The test results for all the parameters already meet the criteria for polymer screening as chemical EOR. Based on the polymer screening test and polymer performance test that have been done, a polymer concentration of 1000 ppm is suitable for polymer injection with a rule of thumb that polymer viscosity should be four times higher than oil viscosity (6.988 cSt) which gives about 26 cP and from coreflood result which gives about 22% ROIP. From these results, this polymer has the potential to be implemented on the pilot scale in a light oil reservoir.

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GLOSSARY OF TERMS

Symbol	Definiton	Unit
API	: American Petroleum Institute	
EOR	: Enhanced Oil Recovery	
FR	: Filtration ratio	
HPAM	: Hydrolyzed Poliacrilamide	
OOIP	: Original Oil in Place	
RF	: Recovery factor (%)	
RF	: Resistance Factor	
RRF	: Residual Resistance Factor	
mD	: mili Darcy	
RPM	: Revolutions per minute	
PV	: Pore Volume	
ROIP	: Residual Oil in Place	
PPM	: part per million	
cSt	: centi Stoke	
cP	: centi Poise	

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