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Parameter Analysis of Polymer on Sandstone Reservoir in Indonesia: An Experimental Laboratory Study

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ABSTRACT - Polymers are often used to increase oil recovery by improving sweeping efficiency. The screening was carried out as a first step in evaluating the test parameters of several polymers of the Hydrolyzed Polyacrylamide (HPAM) type in fluid and sandstone reservoir rocks. The test was carried out using a reservoir fluid classified as light oil (35°API) and at a reservoir temperature (60°C). The HPAM polymers used are A1, F1, F2, F3, and P1 polymers. The test parameters carried out on these 5 types of polymer (A1, F1, F2, F3 dan P1) include a compatibility test for formation water. The rheology polymer test includes concentration vs Tres, and shear rate vs viscosity which aims to determine the type of polymer solution being tested is a non-Newtonian or pseudoplastic fluid group. Thermal stability test of polymer for 60 days to determine the stability of the polymer solution and whether it is degraded or stable. Filtration testing with criteria FR value < 1.2, screen factor test, and adsorption testing using the static method with a standard limit of adsorption value < 400 µg/gr and polymer injectivity test. From these tests, scoring (range 0-100) was carried out to determine polymer candidates in polymer flooding testing. The F1 polymer candidate for the sandstone reservoir was obtained with a score of 82.25. From the scoring results, the selected F1 polymer candidate has a concentration value of 2000 ppm. For thermal degradation, the polymer F1 2000 ppm experienced degradation of 15.5%. The results of the F1 2000 ppm polymer static adsorption test were 54.8 µg/gr. With the RRF = 1 value indicating rock permeability after injection of polymer F1 2000 ppm, it tends not to experience plugging due to injection of polymer solution.

Keywords: Polymer, sandstone, rheology, injectivity.

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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). The polymer screening and performance testing must be done before pilot scale implementation in the oil fields. The partially hydrolyzed polyacrylamide (HPAM) polymers were 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 core flooding 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 light oil reservoirs.

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 that were tested were at 500 – 3000 ppm. The material of HPAM was mixed in injection water (see Table 1 for injection water composition). The experiment consists of several tests conducted experimentally, starting by testing compatibility, shear test, screen factor, filtration, adsorption, thermal degradation, scoring, and injectivity (Poettman and Hause, 1978; Lemigas, 2008). All the tests were carried out at 60°C as the reservoir temperature.

Table 1
Brine/water injection composition

Parameter	Value	Unit
ANION		
Chloride	8748	mg/L
Bicarbonate	1970	mg/L
Sulfate	0.16	mg/L
Carbonate	98	mg/L
Hydroxide	0	mg/L
CATION		
Sodium	6150	mg/L
Calcium	80.2	mg/L
Magnesium	134.2	mg/L
Ferum	0	mg/L
Barium	0	mg/L
Total Dissolve Solid	17550	mg/L

- Compatibility test

  The solubility of HPAM with various concentrations was visually observed at both room and 60°C temperature to investigate the phase solution, color changing, and precipitation.
- Shear test

  All the rheological experiments were performed on Brookfield DVIII with a 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 – 3000 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.
- Screen Factor

  Tests were carried out to determine the qualitative size of the polymer and to determine the viscoelastic behavior of the polymer solution (Sorbie, 1991). Viscoelastic is a characteristic that is viscous and elastic when it is deformed (Jouenne, S and Heurteux, 2017).
- 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 ressure of 2 bars.
- Adsorption test

  The polymer solutions were prepared to conduct a static adsorption test according to Recommended Practice (RP 63) using native core
- Thermal degradation test

  Tests were performed for 3 months at 60°C temperature under anaerobic conditions in sealed glass ampoules.
- TInjectivity test

  HPAM injectivity test was run at the selected concentration (based on the compatibility test parameter, $M < 1$, adsorption value < 400 μg/g) temperature of 60°C, and slow injection rates of 0.3 cc/min, 0.6 cc/min, and 1 cc/min.

RESULTS AND DISCUSSION

Polymer screening on a laboratory scale is carried out to determine the characteristics of polymers in a 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). In this study, the investigation of polymer flood has been performed using a sandstone reservoir. The polymer compatibility test for injection water was carried out at room temperature and reservoir temperature of 60°C. The result of that test is shown in Table 2 which shows the good polymer solutions with clear, no sediment for each of the polymer concentrations.

Table 2
Aqueous stability polymer

Polymer	Aqueous Stability
F1	Clear, no sediment
F2	Clear, no sediment
F3	Clear, no sediment
A1	Clear, no sediment
P1	Clear, no sediment

The rheological properties of the HPAM polymer 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 1 demonstrates variation shear rate from 7 rpm to 330 rpm was conducted on the viscosity of 1 concentration of each polymer at 60 °C temperature. This result presents that 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.

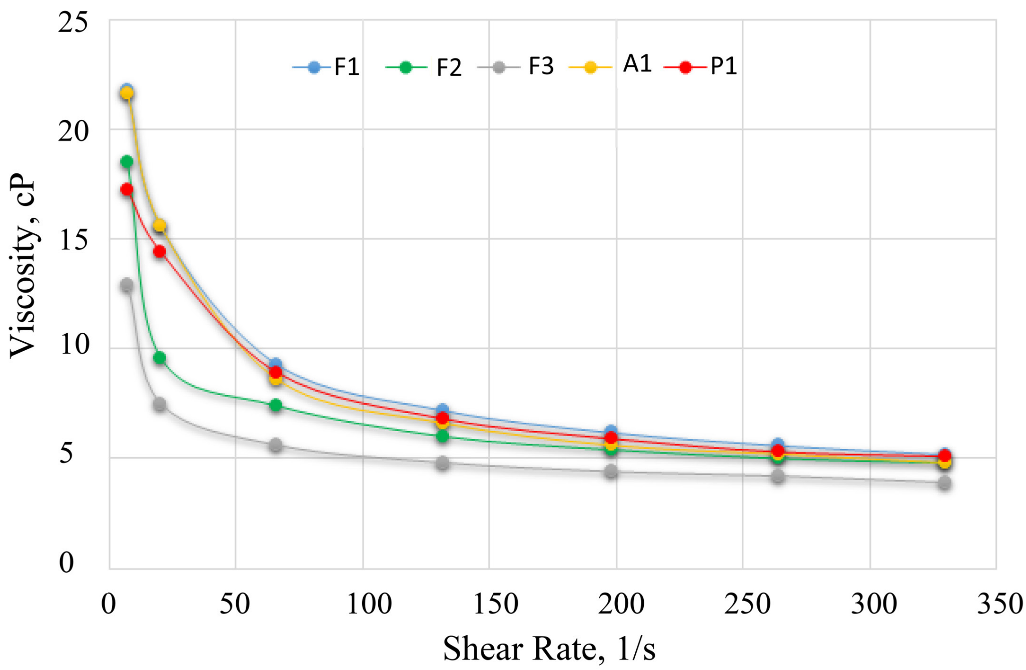

Figure 1
Effect of polymer on shear rate test results

The experiment result of viscosity vs concentration demonstrated the viscosity increasing steadily with increasing polymer concentration at 60 °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. A screen factor test was carried out to determine the quality of the polymer solution. Based on the results of the screen factor test shown in Figure 2 concluded that a higher polymer concentration indicates the polymer solution was long to flow. The equation used to determine the screen factor (Sorbie, 1991) is:

$$SF = \frac{t(\text{solution})\ (\text{second})}{t(\text{solvent})\ (\text{second})}$$

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 through the filter paper. Each concentration solution ensured that polymer hydration had been achieved. The value of the FR for F1 2000 ppm is 1, F2 2000 ppm is 1.2, F3 2500 ppm is 1.1, A1 1500 ppm is 1.02, and P1 2000 ppm is 1.29.

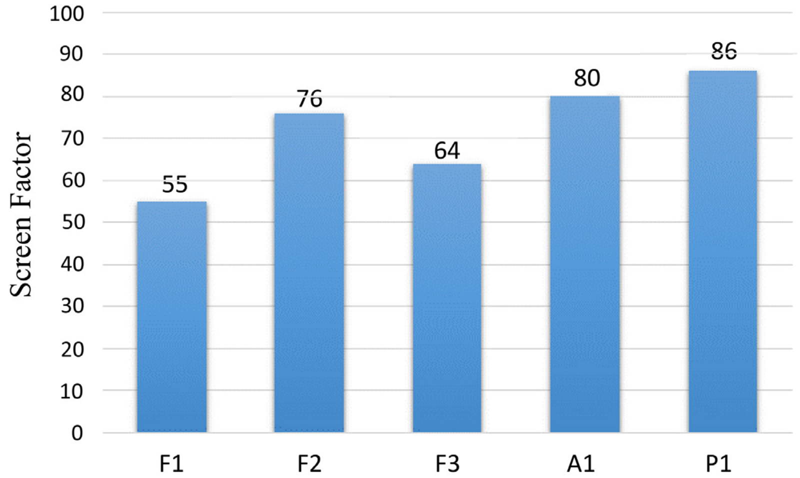

Figure 2
Screen factor test results

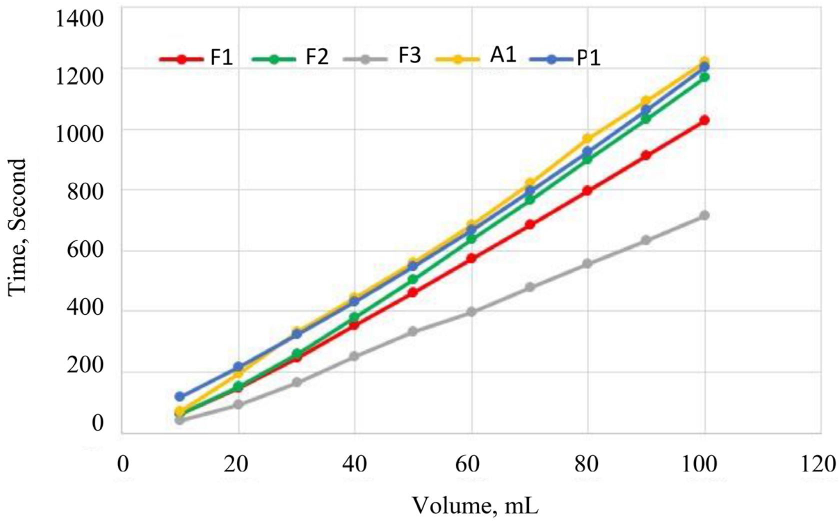

Figure 3
Filter test using 3 µm membrane results

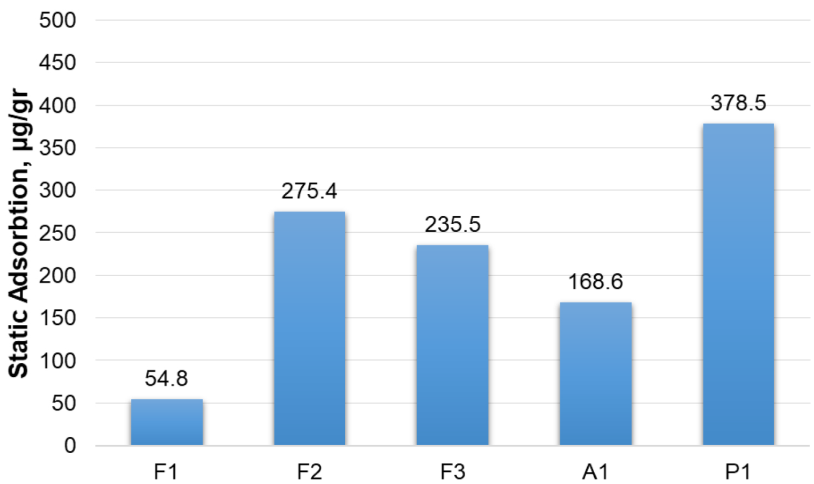

Figure 4
Adsorption static on native core results

This result rapidly indicates that F1, F2, F3, and A1 are 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. If the FR value> 1.2 indicates an indication of polymer causing plugging in rock pores. A static adsorption test is carried out using the native core. Based on each polymer solution, the F1 polymer solution obtained has an adsorption value of 54.8 g/gr and can be seen in the distribution of adsorption on each polymer in Figure 4.

Table 3
Scoring parameter of the polymer

PARAMETER	CATEGORY	SCORE	PERCENTAGE	F1		F2		F3		A1		P1	
				Test Result	Score	Test Result	Score	Test Result	Score	Test Result	Score	Test Result	Score
Price, US$/kg	< 3	20	20	3	**15**	3	**15**	3	**15**	4	**10**	4	**10**
	3 - 4		15										
	4 - 5		10										
	> 5		5										
PV Injected, PV	≤0.3	10	10	0.3	**10**	0.3	**10**	0.3	**10**	0.3	**10**	0.3	**10**
	0.3 - 0.5		8										
	0.5 - 0.8		6										
	> 0.8		4										
Concentration, %	< 0.15	15	15	0.20	**12**	0.25	**9**	0.20	**12**	0.15	**15**	0.20	**12**
	0.15 - 2.0		12										
	0.2 - 0.3		9										
	0.3 - 0.5		6										
	> 0.5		3										
Screen Factor	≤50	10	10	55	**7.5**	76	**2.5**	64	**5**	80	**2.5**	86	**2.5**
	50 - 60		7.5										
	60 - 75		5										
	75 - 100		2.5										
Filtration Ratio	< 1	10	10	1.00	**10**	1.20	**5**	1.10	**7.5**	1.02	**7.5**	1.29	**5**
	1.1 - 1.2		7.5										
	1.2 - 1.3		5										
	> 1.3		2.5										
Static Adsorption, µg/g	< 100	10	10	54.8	**10**	275.4	**6**	235.3	**6**	167.0	**8**	378.5	**4**
	100 - 200		8										
	200 - 300		6										
	300 - 400		4										
	> 400		0										
Molecular Weight, million Dalton	< 10	10	10	8	**10**	12	**8**	20	**4**	15	**6**	15	**6**
	10 - 15		8										
	15 - 20		6										
	20 - 25		4										
	> 25		2										
Thermal Degradation (%)	0 - 10	15	15	15.5	**12**	14.05	**12**	16	**12**	38.6	**9**	35.6	**9**
	10 -20		12										
	20 - 40		9										
	40 -50		6										
	> 50		3										
		100			**86.5**		**67.5**		**71.5**		**68.0**		**58.5**

The laboratory thermal degradation test was conducted to investigate the remaining viscosity after aging as the primary criterion for chemical EOR. F1 presented a good polymer candidate as it performed the remarkable viscosity decay during an aging period at 60ºC temperature (see Figure 5). The viscosity of F1 2000 ppm maintains a constant value in the last 30 days, and the rest after 3 months of the aging period, increased slowly from 22 cP to 27 cP in the first 20 days. The viscosity of F2 2000 ppm maintains a constant value in the last 30 days, and the rest after 3 months of the aging period, decreases slowly from 20 cP to 14 cP with a viscosity retention percentage of 20%. Thus, more effective preparations should be developed to improve their thermal degradation. Based on the results of the thermal stability test, scoring is carried out on several test parameters and characteristics of the polymer. Table 3 shows the F1 polymer has a score of 86.5 assuming the F1 polymer price is 3$/kg, the pore volume injected into the reservoir is 0.3. To understand the performance of the polymer on the rocks, injectivity tests were carried out using polymer F1 2000 ppm. 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.

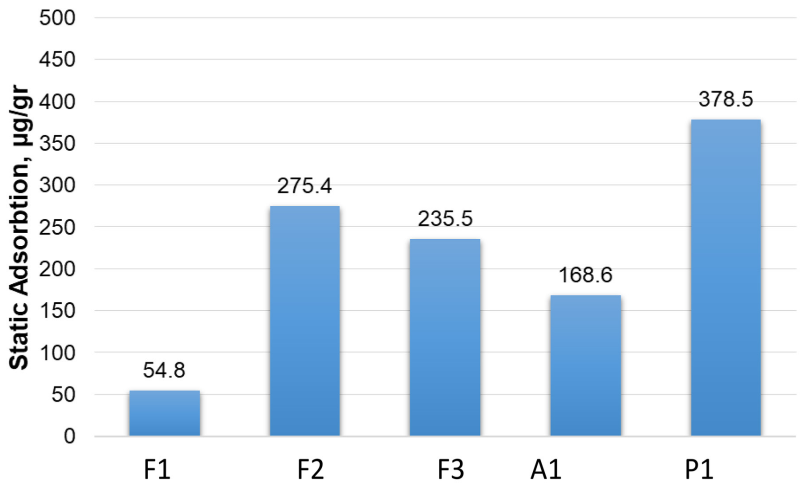

Figure 5
Thermal degradation test results

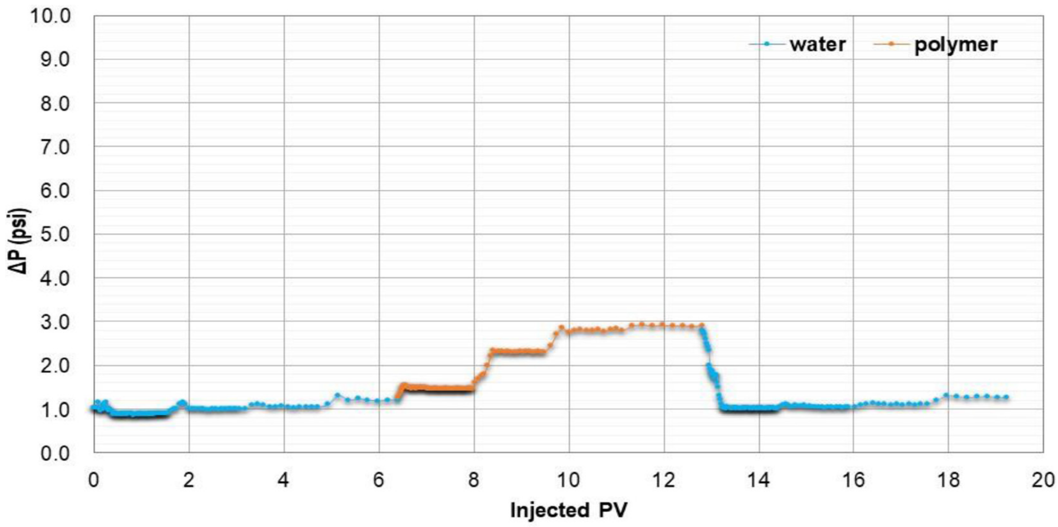

Figure 6
ΔP Distribution vs injected pore volume

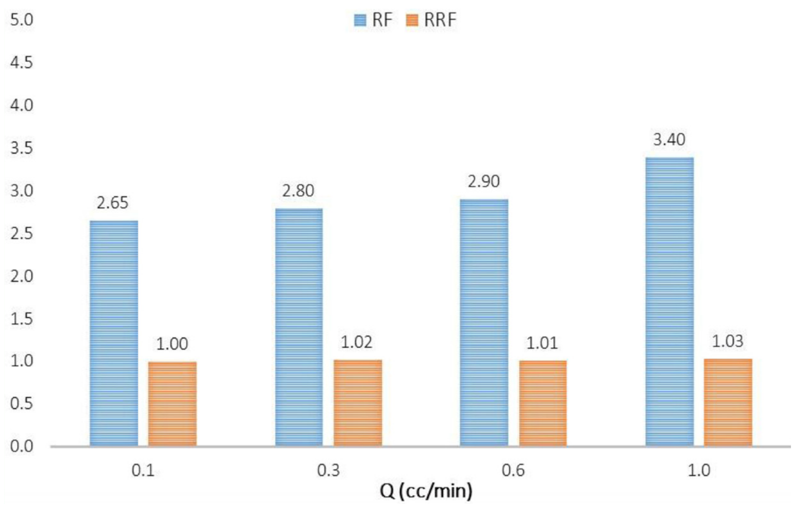

Figure 7
Injectivity test result (RF & RRF)

The injectivity tests were carried out using the step-up rate of 0.1, 0.3, 0.6, and 1 cc/min. The results of the polymer injectivity can be seen in Figure 7. Based on the test results, the polymer has a Residual Resistance Factor (RRF) average value of 1 (one) which means that the permeability of the core plugs after polymer injection were not changing as much after the polymer injection.

Table 4
Native core characteristic

Core	D (inch)	L (inch)	W (gr)	O	Ka (mD)
1	1.5	6.0	316.0	0.28	764.0

CONCLUSIONS

The test results for all of 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, polymer concentration (F1) of 2000 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 22.71 cP. Accordingly, then the conclusion obtained from this study is that F1 2000 ppm was selected. F1 with a concentration of 2000 ppm was resistant in reservoir conditions, it is shown in the thermal stability test (Figure 5). Also, the polymer concentration (F1) had the best score of the scoring parameters shown in Table 3 which gives about 86.5 out of 100. The results of the injectivity test indicated the rate of injectivity affected the RRF value. Based on these results, this polymer has the potential to be implemented on the pilot scale in the light oil reservoir.

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GLOSSARY OF TERMS

Symbol	Definition	Unit
API	American Petroleum Institute	°
cP	Centi Poise	
cSt	Centi Stoke	
EOR	Enhanced Oil Recovery	
FR	Filtration Ratio	
HPAM	Hydrolized Polyacrylaamide	
M	Mobility Ratio	
mD	mili darcy	
ppm	parts per million	
rpm	rotate per minutes	
RP 63	Recommended Practice 63	
RRF	Residual Resistance Factor	
SF	Screen Factor	

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