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Hydrolyzed Polyacrylamide Screening for EOR in an Indonesia Mature Oil Field

Tomi Erfando[1,*], Gerry Siregar[1], Yani Faozani Alli[2] and Yohanes B. D. Wangge[2]

[1]*Department of Petroleum Engineering, Universitas Islam Riau, Jalan Kaharuddin Nasution 113 Pekanbaru, Riau, Indonesia*
[2]*R&D Centre for Oil and Gas Technology "LEMIGAS", Kota Jakarta Selatan, Daerah Khusus Ibukota Jakarta, Indonesia*

([*]Corresponding author's e-mail: tomierfando@eng.uir.ac.id)

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Abstract

Most of Indonesia's oil field has been producing the oil for long period of time. For this reason, enhanced oil recovery (EOR) method become the most promising method to improve oil production for the country. Chemical flooding, especially polymer flooding is the simplest and the most commonly applied chemical enhanced oil recovery technique, since it can be used after water flooding process. Screening is considered the first step in evaluating and selecting potential polymers for reservoirs. Therefore, this paper aims to select partially Hydrolyzed Polyacrylamide (HPAM) base polymers to find suitable polymer for a targeted mature reservoir in Indonesia. A polymer screening study was carried out on 3 HPAM polymers to identify a potential candidate which can withstand reservoir conditions. These are Kerui, Zekindo, and FP 3630S. Initially, a comprehensive rheological (viscosity, shear rate) study was conducted at various polymer concentrations (500 - 2500 ppm) and brine to investigate the polymers. Then, filtration and screen factor test was conducted at various concentrations (1000 - 2000 ppm). Then thermal stability test was conducted at anaerobic condition and 140 °F for 2 months. Finally, for oil recovery used core flooding test. Based on the result of the test, FP 3630S with a concentration of 2000 ppm was chosen for the core flooding test. The test was designed in 3 steps: At first, water injected into the sample, followed by polymer-solvent at 2000 ppm concentrated of 1 PV, the finally injected by water. The results of core flooding showed oil recovery of 28.93 % OOIP. Finally, this study was performed to develop screening criteria and to correlate oil recovery prediction.

Keywords: Enhanced oil recovery, Polymer injection, Screening, Core flooding, Mature oil field

Introduction

Polymer flooding is the most commonly applied enhanced oil recovery method. It's application gains an interest especially in current oil prices [1]. The objective of polymer flooding is to improve mobility ratio between oil and water as well as to reduce viscous fingering by viscosifying the injected water, and thus resulting to better sweep efficiency [2,3]. Based on the field experiences, reports have shown that up to 20 % additional oil may be recovered by polymer flooding [2].

Generally, 2 categories of polymers are used in EOR applications. These are biopolymers such as xanthan and synthetic polymers such as hydrolyzed polyacrylamide (HPAM) [2,3].HPAM polymers are main focus in this study. Polymer flooding by HPAM shows success in different oil applications both onshore and offshore at different reservoir formations e.g., sandstone and carbonates [5].

HPAM is the most often preferred for polymer flooding because the polyacrylamide in the neutral pH environment is slightly positively charged , resulting in a tendency to absorb onto reservoir pore rocks, mainly sand and sandstone as well as absorbs strongly on mineral surfaces [6]. HPAM has a disadvantage, there is easy to hydrolysis. The recommended hydrolysis degree usually ranges from 25 - 35 % to improve the specific properties of polymer solutions. However, the polymer properties are excessively sensitive to salinity and hardness, if the degree of hydrolysis is too large, and will not be water soluble if the degree of hydrolysis is too small [6]. This is because the quality of the polymer is quite adequate, resistant to mechanical degradation, (such as flow rate), and is considered economical compared to natural polymers (xanthan gum) [2]. The type of synthetic polymer selected is a hydrolyzed polyacrylamide (HPAM) polymer, namely Kerui, Zekindo, and FP 3630S. These 3 polymers were selected based on considerations of rheology, solubility, stability, and polymer degradation [7]. According to Delamaide [9] polymer type FP 3630S with a concentration of 1500 ppm was successfully applied to the Pelican Lake field. Surfactant injection was successfully applied in the Shengli field, China on a pilot scale. Surfactant injection of 0.5 PV can increase the recovery value by 10.3 % [8].

However, choosing the right polymers is not easy. The candidate polymers for application should meet the following tests, such as polymer rheology test [9]; compatibility test [10]; filtration test [11]; thermal stability test [12]; and core flood test [13]. This screening was conducted on 3 HPAM polymers at same temperature and salinity, and various concentrations through rheological measurements. Thermal stability test at anaerobic condition was then conducted on the polymers to evaluate the possibility of polymer degradation after long period of ageing. Based on the tests, a core flooding test through synthetic core was carried out to determine the oil recovery.

The key to the success of this study is determined by the following tests. The polymers which have good requirements are suitable for the application. The study aim was to determine the suitable polymer to increase oil recovery and to develop screening criteria for polymer flooding.

Materials and methods

Materials

Material used in this study include synthetic formation water, 3 HPAM polymers and sandstone synthetic core sample. Formation water was prepared based on the composition of the target reservoir. The composition presented in **Table 1**.

Table 1 Compositions of formation water.

Compounds	Formation water (gr/L)
$CaCl_2$	0.1660
$MgCl_2$ 6 H_2O	0.6605
$NaHCO_3$	2.688
Na_2SO_4 10 H_2O	0.00037
Na_2CO_3 10 H_2O	1.44996
NaCl	14.62344

HPAM polymer in powder form with their properties such as Kerui 0.02 (106 gr/mol); Zekindo 400 - 800 (106 gr/mol); FP 3630S 18 (106 gr/mol). A sandstone synthetic core was used for conducting core flooding test at reservoir conditions.

Brine and polymer solution preparation

Brines solution was prepared based on the compositions listed in **Table 1**. Before usage, the brines were initially filtered with 0.45 µm filter paper. Then, polymers solutions were prepared based on API standard for preparation of polymer [14].

All polymers solution were prepared in a glove box so as to maintain minimum oxygen level in solutions, as it may have impact on the polymer viscosity [3]. Initially, the brines were stirred on a magnetic stirrer at a high speed for a few minutes. The, the polymer powder was poured gently on the shoulder of the vortex to avoid agglomeration of polymer. The speed of stirrer was then reduced to after 10 min to avoid shear degradation. Then, the polymers were left overnight to have a homogeneous solutions [14].

Polymers used for this study was provided by PPTMBG LEMIGAS, Indonesia as their commitment to support Indonesia's energy sustainability. The use of the polymers based on PPTMBG LEMIGAS experience to screen the probability of potential polymer for Indonesia's oil field.

Rheology measurements

For multi-faceted systems ranging from pure liquids to colloidal systems and polymer solutions, measured rheological surface properties are relevant. The objective is to measure rheological features of the interfacial layers and any measures of quantitative properties of a material in order to finally pre-determine the choice and optimization of its structure in specific applications.

The rheological properties of the polymer solutions were measured using DV-III Ultra Brookfield. The measurements were conducted at 140 °F to study the rheology of polymers in reservoir temperature. The tests further conducted at reservoir temperature of 140 °F to evaluate the effect of temperature on polymers viscosity. And the tests were carried out at constant shear rate of 7 s-1.

Solubility

There is no direct method to assess solubility parameter in polymer solutions. It just by visualization based on the view of the polymer solutions in beakers. Besides that, polymer solubility can be assessed by: a) low cost visual determination based on visual detection of when the fluid enters a 2 phase region, captured as noticeable cloudiness[15]; b) viscosity measurements based on the difference in viscosity between different solutions; c) differential scanning calorimetry - a method that requires high level of expertise for data interpretation; d) gas liquid chromatography has also been used [16] due its capability of characterize the polymer-solvent system and to investigate the interaction between polymers and non-solvents; and e) the fluorescence probe approach based on an aggregation-induced emission (AIE) is considered as an accurate method for measuring the solubility parameters of a polymer [17].

Filter test

Filter tests is an important test to ensure that polymer solutions are free aggregates and to ensure that proper hydration of polymers have been achieved, filtration tests were performed [18]. The procedure is described in the API RP 63 standard [14]. Levitt [19] presented an overview of the filtration procedures, filter size and material adequate according to the polymer type. It is important to consider that filtration ratio tests are in general not conclusive as screening tests with using associative polymers. Approximately 120 mL of polymer solutions was filter troughed 0.3 micron Millipore cellulose filter under 20 - 25 psi nitrogen pressure, and the time was recorded to calculate the filtration ratio when 20, 40,80, 100 mL. The filtration ratio is calculated according to the following equation.

$$FR=\frac{t100-t80\ \text{(second)}}{\text{t40-t20 (second)}} \qquad (1)$$

Screen factor test

This measurement consists in recording the times for a given volume of polymer solutions (t_p) and water (t_w) to flow through 5 100-mesh screens. The screen factor is defined as the ratio of times between polymer and water SF= t_p/t_w. Measurements were performed at ambient temperature. As described in API RP 63 [14].

Thermal stability test

Stability tests were conducted all 3 polymers at the same brine salinity and ageing temperature in order to study the possibility of polymer degradation over a long period time. [20] described the recommended methodology to assess the thermal degradation. Thermal and chemical degradation results in a significant loss of viscosity, an effect gets worse when divalent ions are present in the brine. Polymers solutions were stored in an oven. Then polymer solutions were stored in an oven set at 140 °F for ageing while viscosity of the solutions were measure at room temperature after specific interval time (2 months).

Core flooding test

The core flooding test used synthetic sandstone core (Benthaimer1). The properties of rock sample are reported in **Table 2**. This test is to study the polymers behaviour in porous media. Core flooding is a test for the injection into a rock sample of a liquid or mixture of fluid. Objectives include permeability measurement, relative permeability, saturation change, fluid injection formation damage, or interactions between rock and fluid. Often from an oil reservoir the core material is used, while some experiments use outcrop rock. At the outset, the fluid is usually a simulated brine, oil, or salt and oil mix (either a crude oil or a refined oil). Crude oil, simulated reservoir salt, refinement of fluids, mud filtrate, acids, foams or other chemical substances utilized in oil field may be included in the injected fluids. The conditions might be at ambient, low confining pressure or high temperature and pressure in the subject reservoir, depending on the aim of the test. Pressure and flow rates are measured at both ends of the core and the core is also examined during test utilizing additional measures such as NMR. A coreflood is normally used to identify the optimal development of an oil reservoir and frequently helps analyze how fluids are injected specifically tailored to increase or increase the regeneration of oil. The core sample should be submitted to a similar saturation history by injecting a similar amount of water (in terms of porous volume (PV)) as done in the field starting from reservoir native saturation conditions [20]. This test was conducted with the aid of Vinci Autoflood Coreflood System (shown in **Figure 1**).

Table 2 Petrophysics properties of core sample.

Rock Properties	
Rock type	Sandstone
Length (cm)	5.80
Diameter (cm)	3.6
Pore Volume (cc)	14.92
Porosity	25.26 %
Average permeability	2345 mD

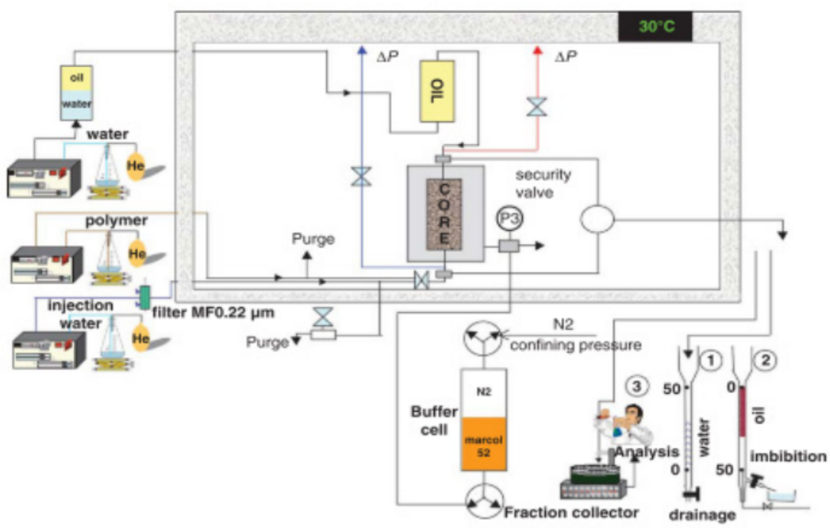

Figure 1 Schematic of Vinci autoflood coreflood machine used for core flooding test [21].

Results and discussion

Solubility test

The prediction of polymer solubility in solvents is one of the most significant applications of solubility parameters. The closer the solvent and solvent solubility parameters, the stronger the solubility of the solvent in a specific solvent.

Based on the visualization of the polymer solutions were conducted the degree compatibility between polymer and the brine. Some polymers were conducted perfectly soluble, clearly, and also slightly soluble. The polymer solutions were conducted perfectly soluble, and clearly are dominated by polymers with low concentration (500 - 1000 ppm). However, in concentrations about 1500 - 2500 ppm are slightly soluble but completely dissolved. The results are reported in **Table 3**.

Table 3 Results of compatibility test.

No	Solutions	Conc. (ppm)	Compatibility
1	FP 3630S	500	clearly
		1000	clearly, perfectly soluble
		1500	slightly soluble, perfectly soluble
		2000	slightly soluble, perfectly soluble
		2500	slightly soluble, perfectly soluble
2	Kerui	500	clearly, perfectly soluble
		1000	clearly, perfectly soluble
		1500	clearly, perfectly soluble
		2000	slightly soluble, perfectly soluble
		2500	slightly soluble, perfectly soluble
3	Zekindo	500	clearly, perfectly soluble
		1000	clearly, perfectly soluble
		1500	clearly, perfectly soluble
		2000	clearly, perfectly soluble
		2500	slightly soluble, perfectly soluble

Polymer rheology

The measurements were conducted at reservoir temperature at 140 °F and also set at constant shear rate 7s-1. As expected it was observed (as shown in **Figure 2**) that the viscosity increase with increasing concentrations. The polymer solutions which has viscosity numbers 4 until 5 times than the oil viscosity are good [22].

Viscosity measurements were carried out at a shear rate of 7s-1 and a temperature of 60 °C which is the reservoir temperature. Kerui polymer types at concentrations of 1500 and 2000 ppm were chosen, because their viscosity is 3 to 4 times the viscosity of oil. The higher the concentration, the higher the viscosity [23]. The same is also the basis for the selection of Zekindo polymers at 1000 and 1500 ppm, and FP 3630S at 1500 and 2000 ppm. Concentrations that pass will proceed to the next testing stage.

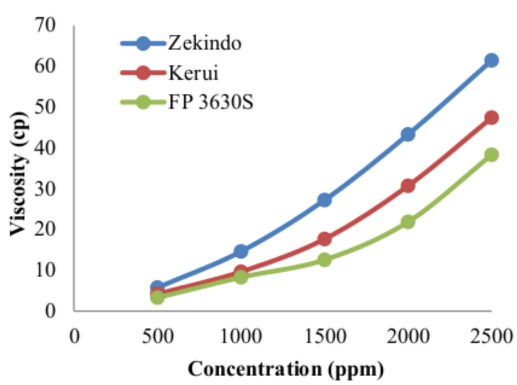

Figure 2 Viscosity test results.

According the results of this graph, it can be seen that the value of Zekindo's viscosity is greater than that of Kerui and FP 3630S. If the terms of viscosity grades Zekindo value is greater, however this can't be the absolute parameter for determining the selection of polymer, it needs more testing to determine the performance of the polymer.

Effect of shear rate

Shear rate test aims to determine the type of polymer solution being tested is a group of non-Newtonian fluid and to determine the ability of the viscosity of the polymer at each of rotational speeds varying from 15, 50, 100, 150, 200, 250 rpm and shear rate of 7s-1. The shear behaviour is necessary so as to avoid high pressure drop during polymer injection in the reservoir. This is because the value of the polymer viscosity will change with changes in rotational speed. This change in value indicates that the polymer is pseudo-plastic (shear thinning). Pseudo-plastic (shear thinning) namely the fluid whose viscosity value is a function of the shear rate [7], but if the viscosity increase as shear stress increases, it called shear thickening [24]. However, understanding the performance of polymer solutions as a function of shear rate is necessary because the velocity in the reservoir is non-uniform. The following graph test results for shows shear rate each polymer type and concentration (shown in **Figures 3 - 5**).

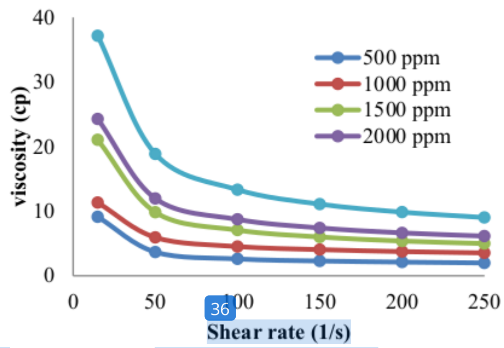

Figure 3 Viscosities of Kerui solutions as a function of shear rate for various concentrations.

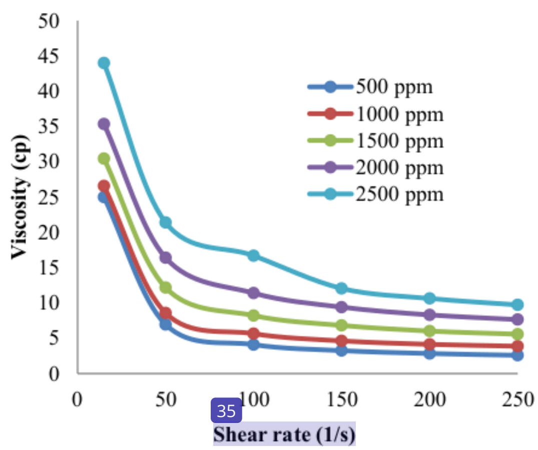

Figure 4 Viscosities of Zekindo solutions as a function of shear rate for various concentrations.

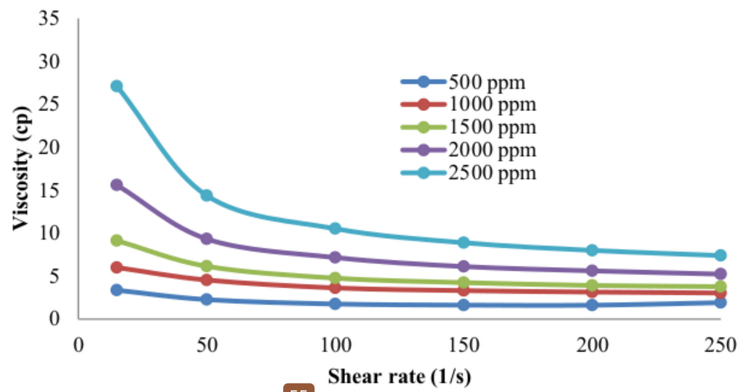

Figure 5 Viscosities of FP 3630S solutions as a function of shear rate for various concentrations.

The shear rates may be transformed into in situ velocities on the basis of rock porosity and permeability knowledge. Some polymer solutions can undergo viscosity hysteresis in terms of shear rate, particularly those with a greater molecular weight. This is because polymer molecules split apart and hence decrease their water viscosity at high shear rate. Such high shears can occur as the polymer solution passes through pumps, chokepoints in piping, through well perforations, and through the reservoir near the wellbore.

Filtration test

Filtration test aims to determine the existence of indications of a solution forming a precipitate (aggregates) at the time of injection [11]. If this happens then the rock pore will be clogged by deposits originating from the injected polymer solution. Polymer solutions carried out by the filtration test include, Kerui 1500 and 2000 ppm polymer solutions, Zekindo 1000 and 1500 ppm polymers, and FP 3630S 1500 and 2000 ppm.

The polymer solution is made as much as 120 mL to be tested for filtration, then filtrated to 100 mL. Then record the flow time at intervals of 10 mL, and stop at 100 mL. The value of the filtration ratio is expected to be < 1.2, if $FR > 1.2$ then there is an indication there is a precipitate in the solution. The equation for calculating the filtration ratio (FR) [18], is;

$$FR=\frac{t100\text{-}t80\ (\text{second})}{t40\text{-}t20\ \ (\text{second})} \tag{1}$$

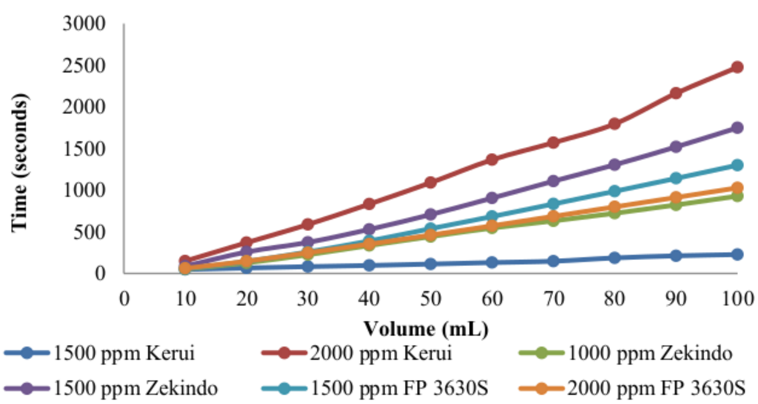

Figure 6 Filtration test results.

Based on the **Figure 6** of filtration test results above, it can be seen that the value of FR < 1.2 seen in the type of polymer 1000 ppm Zekindo, 1500 ppm FP 3630S and 2000 ppm FP 3630S each value 1.0, 1.28 and 1.1. FR value of this solution is considered good and there are no deposits on membrane paper. But this is inversely proportional to the FR value of the 1500 ppm Zekindo solution, which is 1.6. These results indicate the potential for deposition to be quite large and not suitable for injection. Based on the results as shown in **Figure 6**. can be seen in the 2000 ppm polymer solution Kerui forming curved lines, this indicates a blockage in the membrane paper. This also happened to Zekindo's 1500 ppm solution. For 1500 and 2000 ppm Kerui solutions, each with a value of 1.33 and 1.47, it is still worth considering even though the FR value > 1.2. This consideration is taken if the value of rock permeability is large enough and porosity is good. Therefore a Polymer solution having a FR value of 1.2 passes the test [25].

Based on the results shown in **Figure 6** can be seen that the increasing concentration of each polymer, the greater the filtration ratio. However, this is inversely proportional to Polymer FP 3630S (HPAM). This happens because of the hydration process [19]. This process occurs when mixing a polymer solution. Because in the case of the polymer FP 3630S (HPAM) the difference in stirring speed (magnetic stirrer) will result in the process of hydration. Stirring for the polymer FP 3630S (HPAM) with the same speed, but at a concentration of 1500 ppm hydration occurs which causes the polymer solution to become more viscous and difficult to pass through the paper membrane.

Screen factor test

This test has a similar principle to the filtration test, but what distinguishes it is no value ratios such as filtration test and the value obtained without unit or dimensionless. Testing is done to determine the qualitative size of the polymer solution and determine the viscoelastic behaviour of the polymer solution [23,27]. Viscoelastic is a viscous and elastic characteristic when deforming [26]. In this test only looks at the flow time of each solution. The results shown in **Table 4** below.

Table 4 Screen factor test results.

Types of polymer	Concentration (ppm)		
	1000	1500	2000
Kerui	-	34.5	76
Zekindo	35	65	-
FP 3630S	-	64	100

The value of the screen factor test results is obtained from the distribution of synthetic water flow rates of 2 s. From these results it can be seen that the higher the concentration the longer the solution to flow. The equation to get the value of the screen factor [22], namely:

$$SF=\frac{\text{solution flow rates (seconds)}}{\text{solvent flow rates (seconds)}} \tag{2}$$

Thermal stability of HPAM

This test is necessary to know the durability of the reservoir temperature of the polymer solution facing the particular time period. The Kerui 1500 and 2000 ppm polymers, Zekindo 1000 and 1500 ppm, FP 3630S 1500 and 2000 ppm thermal tests were conducted. The findings of the polymer rheology test are based on that. The examination was conducted 60 days with 0, 3, 7, 14, 30, 60 days of observations. This testing temperature is carried out at a temperature of 60 °C. The following graph **Figure 7** is the thermal results test:

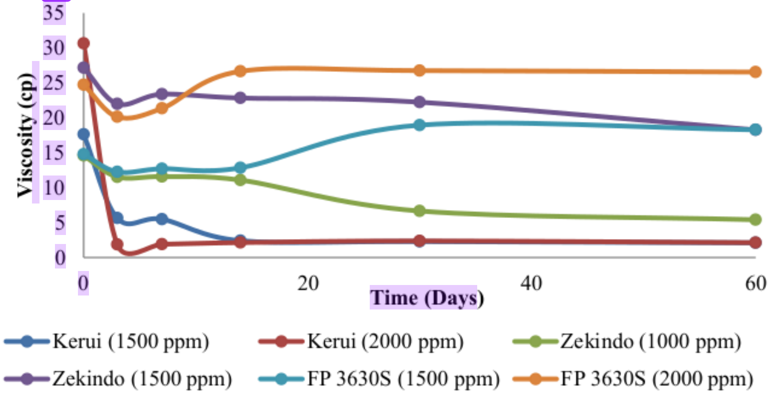

Figure 7 Thermal stability results test.

Based on the results of **Figure 7** shows the effect of heat on the polymer solution. The value of polymer viscosity tends to decrease with the length of heating time. From the observations and measurements made the polymer has degraded. This degradation occurs because of the breaking of the polymer chain during the thermal test process [7]. This degradation will reduce the molecular weight of the polymer and the viscosity will also drop significantly. Range value of degradation that can still be tolerated, which is 20 - 30 % [27]. Based on the graph showed, the decrease in the viscosity value of FP 3630S 2000 ppm polymer type tends to be stable.

The viscosity value of the FP 3630S polymer (HPAM) on the 60th day is larger than the initial viscosity if seen from the table the results of the thermal stability test can be observed. This occurs because the polymer FP 3630S (HPAM) undergoes a hydrolysis process. This process causes the viscosity value to increase from the initial viscosity. However, there is no hard-limit on the upper temperature since it depends on in situ residence time, polymer chemistry, reservoir chemistry, and the degree to which reduced polymer performance is acceptable. Thermal degradation can be greatly accelerated by the presence of dissolved oxygen and iron in the brine. Thermal degradation tests are typically initiated fairly early in laboratory work since long hold-times are required for analysis - often 1 year or more. Thermal degradation can be partially reduced by additives, especially oxygen scavengers [27].

Based on the results of the activity test screening on each polymer, a polymer 2000 ppm FP 3630S was chosen to proceed in the process core flooding. This is because the quality and value of the polymer 2000 ppm FP 3630S is better than other types of polymers. The following table is a screening polymer ranking. It shown in **Table 5**.

Table 5 Summaries of polymers screening in ranking.

Types of polymer	Solubility test	Viscosity test	Shear rate test	Filtration test	Screen factor test	Thermal test	Total
1000 ppm Zekindo	5	5	5	5	3	2	25
1500 ppm Zekindo	5	5	5	1	3	3	22
1500 ppm Kerui	4	5	5	3	3	1	21
2000 ppm Kerui	4	5	5	3	2	1	20
1500 ppm FP 3630S	4	5	5	3	3	4	24
2000 ppm FP 3630S	4	5	5	5	2	5	26

Note: 1 = Very Poor; 2 = Poor; 3 = Fair; 4 = Good; 5 = Very good

Core flooding

Corefloods are important elements of this study. Corefloods are used to know the progress of chemical (FP 3630S) for increasing the oil recovery (RF) [28]. Core flooding test was conducted through core flood experiment mainly to study the polymer behaviour in porous media under reservoir conditions. The polymers solution was conducted FP 3630S with concentration 2000 ppm. The tests were conducted by injecting a slug of water (pre-flush), ahead of polymer, with specific characteristics. The results of rheological tests (shear rate and viscosity) that have been carried out on the 3 types of polymers show that the viscosity value of the polymer decreases with increasing rotation per minute (rpm). Polymer viscosity values tend to decrease faster than below 60 rpm (15 - 50 rpm), and tend to be smaller above 60 rpm (tend to be stable). But what needs to be seen is the value of viscosity = 6 rpm and shear rate = 7 s^{-1}, which represents the flow rate of the polymer in the reservoir from the injection well to the production well [29]. Meanwhile, the high shear rate represents the flow rate around the injection well.

The results of the thermal stability test of Kerui polymer solution concentrations of 1000, 1500 ppm, Zekindo 1500, 2000 ppm, and FP 3630S 1500, 2000 ppm. In this test there were several polymer solutions which experienced a significant decrease in viscosity or degradation after being heated to a reservoir temperature of 140 °F for 60 days [7]. This degradation will affect the flow rate of the polymer at the time of injection, so that the oil sweeping results by the polymer is not good. Because the polymer trip time from injection well to production well is approximately 3 months [27]. Polymer solutions that experienced significant degradation were Kerui 1000, and 1500 ppm polymer solutions, 1500 ppm Zekindo polymer solutions. While the polymer solutions which are quite stable are Zekindo 2000, and 1500 ppm, and 2000 ppm FP 3630S. This is estimated because the FR value > 1.2, so that the indication of blockage and sediment formation is quite large [18].

From the whole series of tests that have been carried out on a polymer solution that has been tested. Polymer solutions are passed and selected for the test core flooding. This is based on the value of viscosity after test thermal 60 days of 26.55 cp, this value is 4 - 5 viscosity of oil. Fluid injection carried out continuously or continuously in the order: injection water, 1 PV polymer, injection water. The acquisition value of oil from the water injection stage (1) is 17.36 % OOIP. This value is actually not in accordance with the value of the acquisition of oil in the stage secondary recovery in general. This is because the samples core used have gone through repeated uses. Supposed to phase core flooding should use new sample (fresh core). Because in this case, the core synthetic used in wettability the sample core is oil-wet. Washing core synthetic can change the wettability of samples core [30].

For cases core with nature oil-wet the acquisition value of oil in the stage secondary tends to be small [31]. Values at the stage are secondary recovery (waterflood) generally 40 - 60 % OOIP [32]. However, because the sample used has oil-wet wettability, the oil is more likely to stick to the rocks, so the value of oil acquisition is small [33]. The effect of 2000 ppm FP 3630S injection of 1 PV adds to oil acquisition of 9.91 % OOIP.

The acquisition value of this oil can still be increased by increasing the volume of injection of polymer solution (PV). This is because at the end of the oil acquisition plot the injection volume still tends to increase. In the final step, the addition of oil recovery from water injection -1 after polymer injection was 1.66 % OOIP. Finally, the maximum acquisition obtained from the core flooding results test was 28.93 % OOIP (as shown in **Figure 8**).

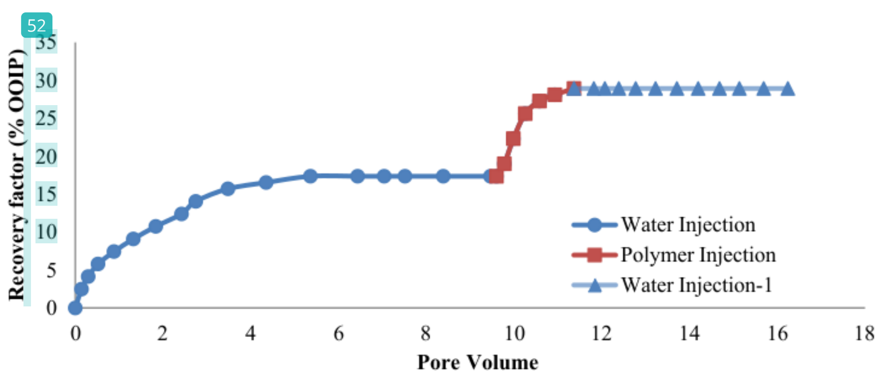

Figure 8 Oil recovery factor from core flooding.

Conclusions

This study helps to understand the best polymer chosen for mature oil field in Indonesia. The study from various methods such as: Filtration test, screen factor test, thermal stability test, and core flooding test for the 3 prequalified HPAM polymers (Kerui, Zekindo, FP 3630S) in order to find a suitable candidate for an Indonesia mature oil filed. The reservoir conditions include temperature and salinity of 140 °F and 20,000 ppm.

Based on laboratory observation, the results of rheology experiments on the 3 kinds of polymers (shear rate and viscosity) indicate that the viscosity of the polymer reduces as revolutions per minute (rpm) increases. Thermal stability test results for the 1000, 1500 ppm, Zekindo 1500, 2000 ppm and FP 3630S 1500, 2000 ppm polymers of the solution Kerui polymers. In this test, various polymer solutions suffered considerable viscosity or degradation when heated for 60 days at 140 °F reservoir temperature.

The solution for the core flood test was passed and chosen. The result of the 2000 ppm FP 3630S injection as much as 1 PV boosted the oil recovery by 9.91 % OOIP. By increasing the volume of polymer solution injection (PV) the recovery value of the oil may be further boosted.

This is because oil recovery still tends to grow near the conclusion of the plot. In the latter phase, oil recovery from water-2 injection was added to 1.66 % OOIP following polymer injection. Finally, the greatest profit achieved by the core flood test findings is 28.93 % OOIP.

Accordingly, then the conclusion obtained from this study is FP 3630S with 2000 ppm was selected. FP 3630S with concentration 2000 ppm was resistant in reservoir condition, it shown in thermal stability test. And also, according in the core flood test, FP 3630S with 2000 ppm was obtained 28.93 % OOIP.

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