STUDY OF ENHANCED OIL RECOVERY WITH ALKALINE SURFACTANT POLYMER INJECTION METHOD BY USING LABORATORY TEST

STUDI PENINGKATAN PEROLEHAN MINYAK DENGAN METODE INJEKSI ALKALI SURFAKTAN POLIMER (ASP) MENGGUNAKAN UJI LABORATORIUM

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ABSTRAK

Salah satu upaya untuk dapat meningkatkan perolehan minyak pada reservoir minyak setelah periode pengurasan primer dan sekunder adalah dengan menerapkan metode *Enhanced Oil Recovery* (EOR). Evaluasi dan pemilihan (*screening*) metode EOR terhadap karakteristik fluida dan batuan reservoir 'N' menunjukkan bahwa metoda yang cocok adalah injeksi larutan alkali surfaktan polimer (ASP). Tulisan ini menyajikan hasil uji laboratorium dalam upaya untuk dapat meningkatkan perolehan minyak pada reservoar 'N' dengan injeksi ASP. Tujuan uji laboratorium tersebut adalah untuk mengetahui penambahan perolehan minyak dengan menginjeksikan larutan ASP pada batuan reservoir 'N'. Berdasarkan hasil uji *compatibility,* tegangan antar muka, reologi, stabilitas panas, filtrasi dan adsorpsi statik pada larutan ASP, maka diperoleh formulasi konsentrasi optimum dari larutan tersebut. Mengacu pada konsentrasi optimum larutan ASP tersebut, kemudian dilakukan uji *core flooding* berdasarkan rancangan injeksi fluida yang sudah ditentukan. Hasil utama dari uji *core flooding* tersebut menunjukkan adanya peningkatan perolehan minyak sebanyak 21.84% OOIP (*original oil in place*). Bila hasil uji laboratorium tersebut diaplikasikan pada skala lapangan dengan menginjeksikan fluida ASP ke dalam reservoir 'N', maka potensi penambahan produksi minyak sebanyak 11.457 juta *barell.*

Kata kunci : Injeksi alkali surfaktan polimer, peningkatan perolehan minyak

ABSTRACT

One effort to improve oil recovery in oil reservoirs after primary and secondary recovery period is to apply the method of Enhanced Oil Recovery (EOR). Screening of EOR on the characteristics of the reservoir rock and fluid 'N' indicates that the suitable method is the injection of alkali surfactant polymer (ASP). This paper presents the results of laboratory tests to increase the oil recovery in the reservoir 'N' with ASP injection. The purpose of the laboratory testing was to determine the additional oil recovery by injecting a solution of ASP in the reservoir rock 'N'. Based on the results of compatibility, interfacial tension, rheology, thermal stability, filtration and static adsorption test on an ASP fluid injection, the optimum concentration of each of the injection fluid is obtained. Referring to the optimum concentration of the ASP, then the core flooding test design based on a predetermined fluid injection. The main result of the flooding test cores showed an increase in oil recovery as much as 21.84% OOIP. When the results of the laboratory test was applied to the field scale by injecting fluid into the reservoir ASP 'N', then the estimated potential increase in oil production as much as 11.457 million bbl.

Keywords: *alkaline surfactant polymer injection, enhanced oil recovery*

I. INTRODUCTION

Oil is trapped in pore rock (sandstone or carbonate) in the primary recovery periodic pushed from reservoir to a well and is lifted using drive mechanism from its own reservoir; such as solution gas drive, water drive or gravity drainage, In the secondary recovery, external fluids; such as water or gas was injected into reservoir through the injection well. The purpose of fluid injection was to maintain the reservoir pressure and push oil into the hole well. After the secondary recovery production achieves economical limit, about two third from original oil in place (OOIP) is still left in the reservoir. The rest of OOIP is left in the reservoir. The rest of OOIP after secondary recovery can be taken using Enhanced Oil Recovery (EOR).

Two third from OOIP left in the reservoir was caused by two main factors namely; microscopic and macroscopic. Microscopic factor covers interfacial tension (IFT) between water and oil phase, and also interaction rocks and fluids (wettability) which caused oil trapped in the pore rock so that the oil cannot loose through was pushed by great pressure (Aladasani et al. 2010). As the size of reservoir pore hole is generally smaller than 0.1 um, it is not surprised if IFT will affect oil mobility. The left oil after driven period was called residual oil saturation (S_{or}). Macroscopic factor took place in reservoir layers with a different permeability value, if the drive through the layer with higher permeability value so oil will be left in the layer which has low permeability value or in not wiped layer. Another reason why all oil cannot be wiped because there is a capillary force in the formation which likes oil, so this force will inhibit water inhibitions into the pore of reservoir rock. This case often happened in the reservoir rock carbonate, because more than 80% from carbonate rock likes oil. Other factors, such as; areal heterogeneity, anisotropy permeability, the lay out of well will also affect to oil wiped by water.

Oil recovery from a driven process is multiplication between displacement efficiency (ED) and sweep efficiency (ES). The application of EOR method focuses on displacement efficiency increment by reducing left oil saturation in the sweep area and increase sweep efficiency by fostering the remain oil in non sweep area. Left oil saturation is the function from capillary number (Nc) which is comparison between viscos force to capillary force. In general capillary number for water injection 10^{-6} to 10^{-7}. In the application of EOR, capillary number increases 10^{-3} to 10^{-4}. Capillary number can be added significantly by reducing interfacial tension or change wettability rock to become like water. Through capillary number can be added by increasing viscos force, but the application is limited. Oil in the non-sweep area can be forced by increasing driven fluid viscosity, modification or changing wettability rock.

One of the EOR methods which has been successfully applied and provides significant contribution in increasing oil recovery is the injection of alkaline surfactant polymer (ASP) as in Daqing oil field, China. From several applied reported pilot tests (Zerpa & Queipo 2004) showed that cumulative oil recovery achieved more than 60% OOIP. In ASP injection method, there are mechanisms and process (Kon et al. 2002) alkaline has three functions, namely: (1) increasing pH (2) decreasing surfactant adsorption which has anionic in nature into reservoir rock and (3) reservoir rock which likes water wet. Surfactant roles for decreasing IFT between oil phase and water so it can increase trapped oil mobility. Whereas polymer role is to increase drive fluid viscosity and decrease mobility ratio between drive fluids and be driven so it will improve sweep efficiency.

South Sumatra basin has several oil fields among other is 'P' field which consists several productive oil reservoirs. In this research (study), the targeted reservoir can applied EOR method, ASP injection is 'N' reservoir. Based on volumetric method, it is assumed OOIP from this reservoir is 52.46 million barrel (bbl), and cumulative production until year 2013, after having applied secondary recovery technology with water injection is 17.99 million barrel (34.31% OOIP). So the remaining oil in the reservoir was 34.46 million, this will become the target to be produced with the application of EOR method of ASP injection.

Fluids and oil reservoir have unique characteristics, therefore interaction between fluids, reservoir rocks and ASP injection fluids also provide unique result. Logical consequence in the lab scale must be conducted before EOR method of ASP injection was applied in 'N' reservoir. The purpose of lab study was to test whether feasible or not to apply EOR method of ASP injection in 'N' reservoir and how much the increase oil recovery will be obtained. The objective of this study to find out the increasing of oil recovery by laboratory test that consist of: (1) screening test of EOR method (2) reservoir fluids test by using ASP solution and certain core (3) core flooding test.

II. METHODOLOGY

A. Method of Screening Test of EOR Method

Before the lab test was carried out in this study, first screening was carried in 'N' reservoir to obtain one or more EOR methods suitable to be applied. Screening method carried out by comparing fluids characteristics data and 'N' reservoir rock to the selection criteria of EOR method (Taber et al. 1997). The lab test was carried out into fluid injection which was used consists of alkaline solution, surfactant, and polymer. Chosen alkali is NA_2CO_3, 'A' surfactant anionic type from petroleum sulfonate. Whereas 'B' chosen polymer included polyacrylamide type.

B. Method of Fluid test and Core

The planning in ASP injection process must meet three main objectives: dissemination of ASP solution, the amount of enough ASP solution injection, maximum sweep from the targeted area so it will increase oil recovery. In order to achieve the objective which will be affected by determination of concentration and slug size ASP solution injection, and then it can be developed based on several analysis of the result of the lab test. Formulation to obtain optimum ASP solution has been done earlier by series of lab tests namely: by combining each alkaline concentration, surfactant, and polymer concentration of optimum ASP which is obtained consists of 1% alkali 0.3% surfactant 'A' and 3000 ppm polymer 'B'. Analysis into formation water from P-19 well conduced to final out the number of and cationic in it and Total Dissolved Solid (TDS) by applying titration method, and also measurement of acidity centigrade (pH). Oil sample taken from P-19 well in subsurface condition in head well. Two characteristics of oil measured namely: viscosity and density at reservoir temperature condition 224.64^{o}F (107^{o}C). Compatibility test into alkali, surfactant, polymer (ASP) was carried out to confirm whether it will form sediment or not in solution during 7 days with room temperature condition. IFT measurement was conducted by spinning drop tentiometer to ASP solution. And reology test conducted to observe polymer solution performance through measurement of viscosity by viscometer.

The analysis of heat stability was conducted to find out resistant power of ASP solution to reservoir temperature in certain time. ASP solution is enough, when the performance remains stable by heat effect (Hirasaki et al. 2011). Heat stability test was conducted by inserting solution at closed glass tube and then put in the oven at reservoir temperature. The time span 0, 3, 7, 15, 30, 45, and 60 days, IFT parameter was measured and viscosity for ASP solution; and viscosity parameter for polymer solution.

The analysis of filtration test was carried out to find out whether ASP and Polymer was saturated perfectly (forming single phase) if it was saturated in formation water. This test was conducted by passing the amount of solution volume on filter paper size 3 micron and it was given one atmosphere pressure. In certain amount of ASP solution and polymer which pass filter paper, the time was noted. Then the result of observation was plotted, between volume (ml) to the time (second).

Static adsorption test was conducted to find out the lost concentration from alkaline surfactant because it was adsorbed by reservoir rocks. The preparation of the test was conducted by refining reservoir rocks, thon it was filtered with filter size 50-200 mesh. After that 5 grams reservoir rocks were soaked in 45 grams alkali surfactant solution so that the weight comparison between reservoir rock and solution became 1:9. The soaking was conducted in the close container at 107^{o}C in 24 hours and was shaken periodically. Next the separation between rocks and alkali surfactant in the form of filtrate was filtered. Filtrate concentration was measured by anionic and cationic titration method (ASTM D3049-89, reapproved 2003). In this method filtrate which contains anionic surfactant was titration by 0.004mol/L benzhetonium chloride solution ($C_{27}H_{42}CINO_2$) cationic in nature. Filtrate concentration was stated as final alkaline surfactant solution after adsorption. Static adsorption was calculated based on the difference initial and final concentration from alkaline surfactant in weight unit divided by weight unit of reservoir rocks. Whereas static adsorption test of polymer solution was carried out by using spectrophotometer ultra violet, by measuring the length of wave in polymer solution before and after the test, Then static adsorption of polymer solution was counted in the unit of weight of polymer solution divided by the unit of weight reservoir rocks.

C. The Method of Core Flooding Test

Core flooding test was carried out to obtain how much the increase of oil recovery from fluid plan which will be injected. The series of equipment for core flooding test (Tobing & Eni 2013) consisting of: injection pumps, fluid tubes (oil, water and ASP), core holder, back pressure valve, and measurement glass. The used injection pump was piston pump type which can inject fluids with constant flow rate (minimum injection flow was 0.01 cc/minute. The pump can inject fluids (oil, water, ASP and polymer) alternately to core holder. Stacked Core was kept in the core holder equipped with overburden pressure so that driven fluids only pass surface stacked core, not pass side of outside part. While back pressure valve got the pressure from nitrogen gas, functioned to maintain pressure system on the core holder. However, it can flow the fluid to measured glass in room pressure.

III. RESULTS AND DISCUSSIONS

A. Preparation Core and Fluid Reservoir

Core samples, which will be used for core flooding, were obtained from P-9 well in the depth span (1296.01 – 1298.51 meter, it was the result of coring (conventional core) with core diameter 3.5 inch. Based on the analysis result of rock type from the result of coring, 'N' reservoir rock including sand stone. From the conventional core with 2.5 m length, was taken the core plug with the average diameter 3.74 cm and the average length 7.8 cm. From the obtained core plug, 4 core plugs were chosen which have similar porosity value and absolute permeability. After that, the 4 core plugs were composed serially (core plug number 4, 7, 8, and 24) and formed the stacked core with 30.37 cm long. The average porosity value of stacked core 28.08% and the rock characteristics of stacked core that used in the core flooding test shown in Table 1.

Fluids characteristics data and 'N' reservoir rocks were shown in Table 2, then the data was compared with the parameter criteria of EOR method selection. (Taber et al. 1997). The result of EOR method selection which was conducted into fluids characteristics and reservoir rocks in general, it was obtained from one suitable method. However, the result of EOR method selection into fluids characteristics and 'N' reservoir rocks showed that ASP injection was suitable to be applied with the note, because reservoir temperature was 224.64^{o}F (107^{o}C) more than the limit of temperature criteria (or less than 200^{o}F or 93.3^{o}C), From the screening result of EOR method which was obtained, next in the lab test on ASP solution which was formulated, added organosulfur compounds as stabilizer so it meets the criteria in the stability test.

The results of content analysis of cationic and anion from formation water and water injection were shown in Table 3, indicates that Total Dissolved Solid (TDS) value was 18176.7mg/L. The analysis result showed that formation water including in the soft brine category or it has low hardness of water. This was shown with cationic existence divalent Ca^{++} and Mg^{++} in each formation water was 30.1mg/L and 42.5mg/L respectively. If a grain of polymer was

Table 1
Data of core plug characteristics

No. Core Plug	Length (cm)	Diameter (cm)	Surface Square (cm^2)	Porosity (%)	Absolute Permeability (mD)
4	7.95	3.7	11.34	27.62	2945
7	7.89	3.7	11.34	28.31	2765
8	7.67	3.7	11.34	26.91	3033
24	7.86	3.7	11.34	29.14	3090

Table 2
The screening result of ASP injection method to 'N' Reservoirr

No	Characteristies of Fluida and Reservoir Rock			Screening Criteria Method of ASP Injection		Remark
1	Oil Gravity	ºAPI	24	> 20 ↗	35 ↗	Suitable for ASP Injection
2	Oil Viscosity @ T_{res}	cp	2.02	< 35 ↘	13 ↘	
3	Oil Saturation	%	65.2	> 35 ↗	53 ↗	
4	Types of Rock	SS/C	SS	prefered	SS	
5	Average Permeability	mD	3941	> 10 ↗	450 ↗	
6	The Depth	ft, ss	4265.3	< 9,000 ↘	3250	
7	Reservoir Temperature	ºF	224.64	< 200 ↘	80	
8	Reservoir Pressure	psig	1861	Not Critical		
9	The average Porosity	%	28.7	Not Critical		
10	The average of Water Saturation	%	34.8	Not Critical		

↗ = It was suggested that for the value of reservoir characteristics is higher
↘ = It was suggested that for the value of reservoir characteristics is lower
80 = The average value of reservoir characteristics which is used
SS = Sandstone, C = Carbonat

Table 3
The analysis of formation water

Components		Formation Water meq	Formation Water mg/L
CATION			
Sodium	Na^{2+}	297.23	6835.4
Calcium	Ca^{2+}	1.50	30.1
Magnesium	Mg^{2+}	3.50	42.5
IRON	Fe^{2+}	0.00	0.0
Barium	Ba^{2+}	0.17	11.5
ANION			
Cloride	Cl^{-}	280.00	9928.0
Bicarbonate	HCO_3^{-}	21.19	1293.2
Sulfat	SO_4^{2-}	0.00	0.0
Carbonat	CO_3^{2-}	1.20	36.0
Hydroxida	OH^{-}	0.00	0.0
TDS (mg/L)			**18176.70**

saturated in the formation water (with low hardness of water) in the preparation of making polymer solution, it is expected there will be no viscosity degradation significantly to the polymer solution (Don & Paul 2003) or the viscosity of polymer solution remains the same. In addition, when the polymer was injected into reservoir rocks which contain formation water. When surfactant was saturated in the formation water (with low hardness of water) or the preparation of making surfactant solution, so it is expected it will form saturated compounds perfectly so that it did not cause clog on pore throat of reservoir rocks. The acidity (pH) from formation water was 8.78 showed acid situation so it meets to be applied ASP injection (Han et al. 2006). The result of oil characteristics analysis showed that oil viscosity and oil density at reservoir temperature (107ºC) 2.02cp and 0.8842 gr/cm respectively including light oil category.

B. Screening Test of ASP Solution for "N" Reservoir

The compatibility test for three ASP solutions that contain of alkaline (Na_2CO_3) with the concentration of 0.6%, 0.8%, 1.0% respectively, but the concentration of surfactant and polymer for ASP solutions were not varied that is 0.3% and 3000ppm, respectively. The experiment by using ASP solutions indicated that all solutions mixture resulted in yellowish and there were not formed a precipitation. Therefore it can be concluded that the results compatible. Yellow the high color was caused interaction existence between polymer and ions that existed on formation water. Because it was observed from compatibility test, it formed sediment on ASP solution that may block on reservoir rocks, so it happened change of color was not considered as in in compatible condition.

IFT Measurement of ASP solution for IFT alkaline mixture (Na_2CO_3) with of 0.6%, 0.8%, 1.0% respectively and surfactant also each polymer on constant concentration namely: 0.3% and 3000 ppm, has been carried out and as solution was formation water. IFT measurement was conduced after ASP solution experienced 224.64^{o}F temperature which represented real reservoir conditions, and the results can be seen in Table 4. The lowest IFT value (7.14x10^{-4} dyne/cm) of ASP solution was achieved with the concentration of alkaline, surfactant and polymer is 0.1%, 0.3% and 3000ppm, respectively. The results of measurement which was obtained showed that the higher alkali concentration, so IFT value was lower. However, the use of alkaline as fluid injection was not suggested more than 1%, because it can cause of scale formed on the production equipment.

Based on oil recovery plot to capillary number (Berger and Lee 2002), in order to increase the number of oil recovery which significant enough, at least capillary number must increase 10^{-4}, or more. Capillary number which was obtained after water injection was finished about 10^{-6}, whereas IFT value between oil and water during water injection was about 1 to 10 dyne/cm to increase capillary number from the value 10^{-6} to 10^{-4}. IFT value must be decreased to 10^{-2} dyne/cm or more so it can increase oil sweep efficiency. Based on IFT value which was obtained from alkaline mixture 1%, surfactant 0.3%, and polymer 3000 ppm were 7-4 x10^{-4} dyne/cm. Therefore, ASP solution was enough to be used as fluids injection to increase oil recovery (Berger and Lee 2002).

The viscosity of polymer solution was measured using Brookfield viscometer. Because 'B' polymer includes polyacrylamide which is classified non-newtonian fluid, so viscosity value is not linear function from shear rate value. The measurement of polymer viscosity based on shear rate value 7.0 seconds-1, because shear rate value was analogy with injection fluids flow from injection well to production well with 1.0 feet/day rate. The measurement of polymer viscosity must be conducted at reservoir temperature 224.64^{o}F. However, due to viscosity measurements on open system, so it was impossible to do measurement at reservoir temperature. Because at reservoir temperature it must have happened evaporation from the soluble fluids namely formation water (water evaporated point was 85^{o}C). Therefore, the measurement was carried out on three observation points namely 30^{o}C, 50^{o}C and 80^{o}C temperature. Then, from three observation points viscosity value were conducted extrapolation so it achieved 224.64^{o}F temperature. The results of value measurements of polymer solution viscosity for each concentration 2500, 2700 and 3000 ppm showed in Table 5. From the result of measurement which was obtained showed that the higher polymer concentration, polymer viscosity value will increase. The objective of adding polymer on injection fluids in order to be higher from oil viscosity and this was conducted to avoid fingering effects (Wei and Yongan, 2005). Considering oil viscosity at 224.64^{o}F temperature was 2.02 cp, so injection fluid viscosity must be higher than the oil viscosity. The result of measurement of polymer solution viscosity with concentration 3000

Table 4
The result of IFT measurement of alkali surfactant and polymer

Solution of Alkali Surfactant - Polymer	IFT, dyne/cm
0,6% Alkali, 0,3% Surfactant, 3000ppm Polymer	9.67E-03
0,8% Alkali, 0,3% Surfactant, 3000ppm Polymer	2.73E-03
1.0% Alkali, 0,3% Surfactant, 3000ppm Polymer	7.14E-04

Table 5
The result of polymer viscosity measurement

Polymer Concentration,ppm	Viscosity,cp
2500	12.78
2700	15.23
3000	24.60

Table 6
The result of thermal stability test at 224 °F temperature

Solution	0 day IFT, dyne/cm	3 days IFT, dyne/cm	7 days IFT, dyne/cm	15 days IFT, dyne/cm	30 days IFT, dyne/cm	45 days IFT, dyne/cm	60 days IFT, dyne/cm
1 % A, 0.3 % S, 2500 ppm P	0.0000401	0.0009127	0.0001281	0.0001012	0.0040308	0.0009956	0.000612
1 % A, 0.3 % S, 2700 ppm P	0.0007143	0.0009127	0.0000784	0.0001678	0.0009127	0.0005282	0.000314
1 % A, 0.3 % S, 3000 ppm P	0.0011762	0.0016797	0.0013424	0.0006063	0.0002587	0.0003775	0.000149

A = Alkaline, S = Surfactant, P = Polymer

ppm at 224.64oF temperature was 24.6 cp or more than 10 times oil viscosity value. So it will increase drive fluid viscosity and improve sweep efficiency or it will decrease the comparison between mobility and drive fluid which was driven. Or in other words, it can increase oil sweeping in macro and in the case it was applied on polymer injection slug plan.

As ‘N’ reservoir temperature as higher enough namely: 224.64°F (107°C), so at the temperature is generally ASP solution (IFT parameter and viscosity) and polymer (viscosity parameter) will experience heat degradation. In order to find out, there is phenomenon, it has been tested heat stability test to both parameters. As ASP solution and polymers which will be injected into reservoir that has resistant to the reservoir temperature, both solution were added as organosulfur compounds as chemical resistant at or each heat stabilizer was 0.04%. The result of stability test for IFT parameter to ASP solution (1% alkali Na_2CO_3 + 0.3% surfactant) with each polymer concentration 2500, 2700 and 3000 ppm for a time period 0,3, 7, 15, 30, 45 and 60 days showed in Table 6. IFT value from the third ASP solution, for the test for until 60 day showed IFT value was stable namely, it is about order 10^{-3} and 10^{-4} dyne/cm. The result of heat stability test for viscosity parameter into ASP solution for the period 30 days, it can be seen in Figure 1. Viscosity value for polymer 2500, 2700, and 3000 ppm showed the value was stable after 15 days test, although there was viscosity value change which was not significant on the test day 3, and day 7. Whereas the result of heat stability test for viscosity parameter into polymer solution 2500, 2700 and 3000 ppm there showed in Figure 2. The stability of IFT value and viscosity in ASP solution didn’t experience heat degradation phenomenon, or it can be said it passed in heat stability test.

The result of filtration test in the form volume plot to the time for ASP solution (1% alkaline Na_2CO_3 + 0.3% surfactant + 3000 ppm polymer) and polymer solution 3000ppm, It can be seen in Figure 3. Filtration test was met, if the plot between solution volume passed filter paper into time in form of straight. Time, it meant, it was not in the form of precipitation. Beside filtration ratio (FR) value which was met smaller from 1.2 (Don & Paul 2003). Filtration ratio for ASP and each polymer 1.01 and 1.14. Both FR value for ASP and polymer was still

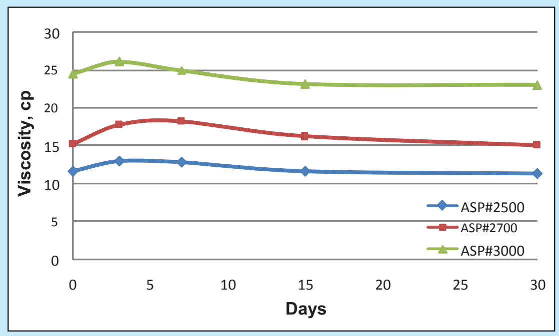

Figure 1
The result of thermal stability test of polymer solution

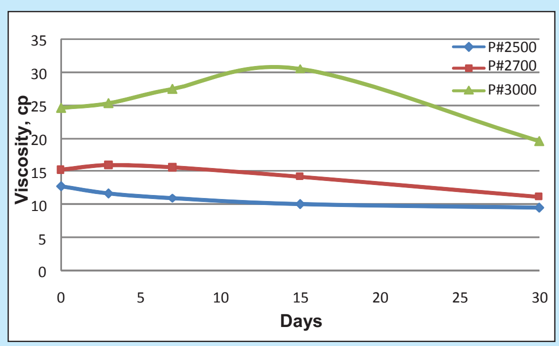

Figure 2
The result of thermal stability test of polymer solution

smaller 1.2, and also formed straight line. This mean that both solution met fluids injection.

The result of static of adsorption of ASP solution (1% alkali Na_2 CO_3 + 0.3% surfactant + 3000ppm polymer) was 170.0μg/g. Where as static adsorption of polymer solution cannot be measured because it has very small value or in the form of trace only. Adsorption test was an important step because from test result, it was found out chemical loss due to interaction with the rocks. The greater chemical loss will cause the effort of increasing oil recovery became non-effective, because the decrease of concentration from alkaline, surfactant or polymer it will also decrease the function of each solution. Therefore, it must be certain that chemical absorbed by the rocks as minimal as possible. The result of static adsorption which has been tested to ASP solution or polymer not more than 400 μg/g. This showed that chemical loss ASP and polymer were relatively small (Han et al. 2006), so in was expected, that it will be effective as fluid injection.

C. The injection of ASP solution into 'N' The ASP Solution Core Rocks.

In order to meet initial conditions fluid saturation in stacked core two steps were conducted as follows (Tobing & Eni 2013): (1) Saturation of formation water to achieved 100% (2) oil Injection to achieve Soi (initial oil Saturation) and Swc (connate water Saturation). From Step 1, it was obtained pore volume (PV) 93.0cc, and absolute permeability value 1674.04 mD. On the second step, it was obtained connate water saturation (Swc) 37.73% (35.09cc) and initial oil saturation (Soi) is 62.27% or 57.91cc.

Based on the results of several laboratory test carried out, so it has been planned the composition of fluid injection based on the fluids characteristics data and reservoir rocks. By applying counting method which was developed by Don and Paul, so the plan fluids injection on stacked core continually with the sequence as follows (1) first step, to inject water-1 slug 0.88 PV (2) Second to inject slug ASP solution 0.30 PV (1% alkali Na2CO3, 0.3% surfactant and 3000 ppm polymer) (3) Third step to inject polymer slug 3000ppm, 0.3 PV (4) Fourth step, to inject water-2 slug 0.82 PV. The plot of oil recovery to volume injection from 2 steps initial condition and 4 steps injection was presented in Figure 4. Oil recovery due to water-1 injection was 0.88 PV it was obtained 46,55% OOIP. Based on the

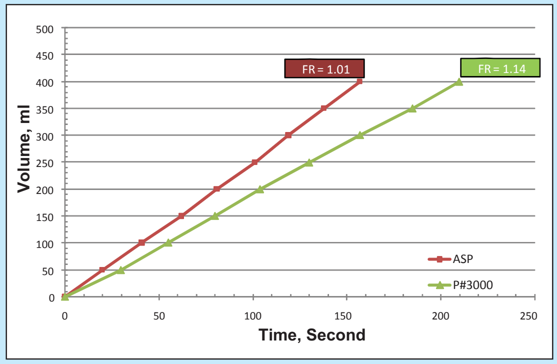

Figure 3
The result of ASP filtration and polymer test

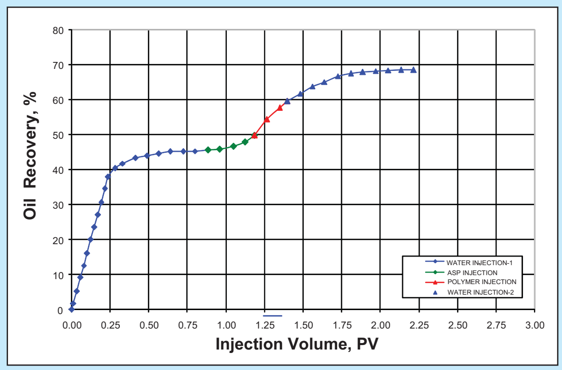

Figure 4
The plot of oil recovery to injection volume

figure showed that water injection from 0.72 PV to 0.88 PV provided additional oil recovery only 1.04% OOIP. This was because oil recovery has approached residual oil saturation. Due to ASP solution injection 0.30 PV at stacked core, it added oil recovery 3.2% OOIP, and the effect at polymer solution injection (3000 ppm) 0.2 PV added oil recovery 9.76% OOIP. Oil recovery, due to polymer injection was still possible to be increased by adding the amount of PV polymer solution injection, because at last part from oil recovery plot to volume injection still showed the tendency to increase. The role alkaline solution at ASP slug (Han et al. 2006), beside it can decrease interface pressure between oil phase and water, it can also change wettability rocks from oil wet to water wet so it can release residual oil from rock. While the role of surfactants can also decrease interfacial tension between oil phase and water (1.18

x 10^{-03}dyne/cm), so it can increase oil mobility which has been loosen from the process role by alkaline before. And the role of polymer was to increase sweep fluids viscosity (26.07cp) which will decrease the ratio mobility between drive fluids and driven fluids so it will improve volumetric sweep efficiency (9.76% OOIP). Then additional oil recovery due to water-2 injection 0.82 PV after polymer solution injection 8.89% OOIP, so that cumulative oil recovery which can be obtained from fluid injection plan was 68.39% OOIP. Therefore, the additional oil recovery at stacked core flooding test due to chemical injection with the sequence ASP slug 0.30 PV 1% alkaline Na2CO3, 0.3% surfactants and 3000 ppm polymer, slug 0.20 PV (Polymer 3000 ppm) and slug 0.82 PV (water) was 21.84% OOIP.

When core flooding plan mentioned above was applied at field scale in 'N' reservoir through well injection and certain injection rate from ASP solution also meets engineering practice requirements, so potential oil recovery addition, if it was considered which effects sweep efficiency only was 11.457 million barrel (bbl). In addition, a feasible test or it was not applied ASP injection method on 'N' reservoir depended on the result of economic study and the criteria of success which was decided.

IV. CONCLUSIONS

From the screening result and the laboratory test Alkaline Surfactant Polymer injection for increasing oil recovery at 'N' reservoir, so it was obtained several conclusions as follows:

EOR method screening to fluid characteristics and 'N' reservoir rocks showed that EOR method which was suitable to be applied was with Alkaline Surfactant Polymer injection. All fluids characteristics and reservoirs rocks which were tested have passed screening, except reservoir temperature.

From the results of compatibility test of Alkaline Surfactant Polymer solution with brine was shown there was no precipitation, so mixed solution can be stated compatible. The existence of color change was caused interaction between polymer and ions that exist water formation, so that this didn't change the condition became in compatible.

By adding organosulfur compound as thermal stabilizer on Alkaline Surfactant Polymer solution and based on the result of thermal stability test which has been conducted at reservoir temperature on Alkaline Surfactant Polymer solution can be overcome.

Based on the results of rheology, thermal stability, filtration, and also static adsorption to Alkaline Surfactant Polymer solution, so optimum formulation of Alkaline Surfactant Polymer solution which was obtained consist of: 1% alkaline Na_2CO_3, 0.3% surfactant and 3000 ppm polymer, so Alkaline Surfactant Polymer solution met to be used on core flooding test.

From the result of core flooding test by injecting water slug (0.88 PV), ASP (0.30 PV) and Polymer resulted cumulative oil recovery 68.39% OOIP. The increase of oil recovery because ASP injection and polymer was conducted the number of 21.84% OOIP and if it was applied at field scale in 'N', reservoir so potential oil production addition was estimated 11.457 million barrel (bbl).

LIST OF SYMBOLS

FR = $(T_{300\ ml} - T_{200\ ml}) / (T_{200\ ml} - T_{100\ ml})$

IFT = Interfacial tension

N_c = $\frac{v\mu}{\sigma}$, Capillary number

$T_{300\ ml}$ = The time that is needed of solution is 300 ml to pass filter paper.

v = Darcy velocity, m/second

μ = Viscosity, cp

σ = Interfacial tension, dyne/cm

OOIP = Original Oil In Place, bbl

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