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Dedy Kristanto*, Hariyadi, Yulius Dedy Hermawan

Abstract

The utilization of chemical flooding to improve oil production in a large scale has many used for the oil field. Some cases have a success, and the others have failed when full scale project implemented. Before chemical flooding implemented, once of the recommended best practice to be done is chemical compatibility based on the reservoir characteristic of the layer as a target in improving oil recovery. Hence, coreflooding test in the laboratory to be an important thing to conduct in other to knows and determine the chemical performance after screening phase. The study of coreflooding test in laboratory, shows that the measurement of surfactant and polymer properties have a good result to be used as an injection fluid in other to improve oil production. Surfactant-polymer injection which has concentrations of 3000 ppm and 1000 ppm with injection mechanism of 0.3 PV surfactant and 0.2 PV polymer gives the result of improving oil production it about 12.89%. Furthermore, based on the qualitative analysis obtained that the used of surfactant SS-B8020 as an injection fluid shown that plugging has not occurred in the reservoir rock pores, it means that the injection fluid was compatible with these reservoir rock.

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Current Issue

A LABORATORY STUDY OF SURFACTANT-POLYMER INJECTION ON THE COREFLOODING TEST FOR ENHANCED OIL RECOVERY

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ABSTRACT

The utilization of chemical flooding to improve oil production in a large scale has many used for the oil field. Some cases have a success, and the others have failed when full scale project implemented. Before chemical flooding implemented, once of the recommended best practice to be done is chemical compatibility based on the reservoir characteristic of the layer as a target in improving oil recovery. Hence, coreflooding test in the laboratory to be an important thing to conduct in other to knows and determine the chemical performance after screening phase. The study of coreflooding test in laboratory, shows that the measurement of surfactant and polymer properties have a good result to be used as an injection fluid in other to improve oil production. Surfactant-polymer injection which has concentrations of 3000 ppm and 1000 ppm with injection mechanism of 0.3 PV surfactant and 0.2 PV polymer gives the result of improving oil production it about 12.89%. Furthermore, based on the qualitative analysis obtained that the used of surfactant SS-B8020 as an injection fluid shown that plugging has not occurred in the reservoir rock pores, it means that the injection fluid was compatible with these reservoir rock.

Keywords: Coreflooding; Chemical flooding; Enhanced oil recovery; Surfactant-polymer.

INTRODUCTION

As the production period of a field increases, its productivity decreases. On the other hand, the required reservoir pressure to flow the oil into the production well decreases as the production rate increases. It is understandable that the increasing amount of oil production will decrease the natural energy of the reservoir. To be able to produce oil after the natural energy of the reservoir decreases, the next stage of oil recovery is required (Rukmana, D. et al., 2018).

Chemical injection is considered one of the most advanced methods for enhanced oil recovery, whereby chemicals are added to the reservoir through injection wells. The primary objective of chemical injection is to alter the physical properties of the reservoir fluids, with a focus on reducing interfacial tension. This is critical because a high interfacial tension can significantly reduce the mobility of oil in the reservoir, leading to a decrease in production rate during both the primary and secondary recovery stages. Numerous successful studies on chemical injection have been conducted by previous researchers, either through feasibility or research studies (Wang, Z. et al. 2001; Ayirala, C.S. 2002; Berger, D. et al. 2002; Goddard, et al. 2004; Anderson, A. G., 2006; Kristanto, D. et al. 2008; Nugroho, S. B., et al. 2012) or laboratory experiments (Buckley, S. J. 1997; Ashayer, R. et al. 2000; Kristanto, D. et al. 2006; and Kristanto, D. 2012).

Generally, chemical injection is classified into three types: alkaline injection, surfactant Injection, and polymer injection. With the development of research, a combination of surfactant and polymer injections has been discovered, known as micellar-polymer flooding. In this case, the micellar-polymer flooding has a higher oil recovery than the other. Chemical injection has a promising outlook for reservoirs that have undergone successful water injection or waterflooding (Abrams, A. 1988), and it also has high economic value (Goddard et al. 2004). However, several factors can influence the success of chemical injection, such as temperature, reservoir type, permeability, and wettability (Abrams, A. 1988; Ashayer, R. et al. 2000; Ayirala, C. S. 2002; Anderson, A. G. 2006).

The objectives of this study are to conduct coreflooding studies utilizing particular surfactants and polymers, identify the injection scenarios that would result in the best oil recovery, and verify the compatibility of these materials before implementation in the oil field.

THEORY AND METHODS

Previous researchers have conducted extensive studies on surfactants, which have the ability to decrease interfacial tension and improve oil recovery. Among these researchers is Berger, D. et al. (2002), who focused on the surfactant's ability to decrease interfacial tension between the formation water (brine) and residual oil, leading to an increase in the Capillary number. The Capillary number (N_c) is used to represent the release of oil that is still trapped in the porous medium. The Capillary number (N_c) is a function of the Darcy velocity (v), which drives the movement of fluids trapped in rock pores, and the viscosity (μ), which is the resistance of fluids to flow. The effect of Capillary number (N_c) on oil recovery is shown in Figure 1.

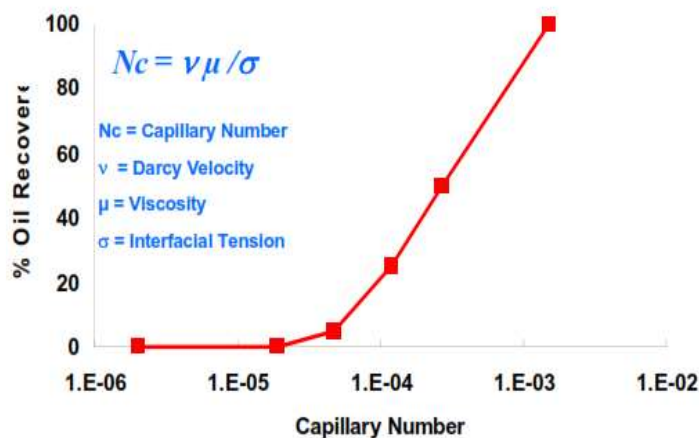


Fig. 1. Relationship between capillary number on oil recovery (Berger, D et al. 2002)

A Capillary Number of around 10^{-6} has been observed in field cases where waterfloods (the use of water for displacement) have been implemented, and this can increase by two to three times to push the oil to the maximum limit (Abrams, A. 1988; Berger, D. et al. 2002). The interfacial tension (IFT) in flood cases ranges from 10^1 to 10^0 mN/m (Abrams, A. 1988). When using surfactants, the surface tension can be reduced to 10^{-2} mN/m or less, which can increase the Capillary Number by two to three times (Abrams, A. 1988; Ashayer, R., et al. 2000; Berger, D., et al. 2002).

Polymer flooding improves the oil recovery from heterogeneous reservoirs by mobility control, combined with disproportionate permeability reduction. Mobility of the injected fluid is represented with respect to the mobility of displaced fluid, in terms of mobility ratio. The mobility ratio is higher during water flooding, signifying that water is more mobile than oil. This leads to early breakthrough of water flood and lower macroscopic sweep efficiency. The injection of polymer solution results in higher oil recovery by reducing the mobility ratio and improving the macroscopic sweep efficiency (Sorbie and Phil, 1991).

High-molecular-weight polyacrylamide has been widely used under mild conditions, but its poor tolerance to high temperature and high salinity impeded the use in severe oil reservoirs (Kamal et al., 2015). Polyacrylamide is non-ionic in nature in the un-hydrolyzed form. Non-ionic polyacrylamide is not used for chemical EOR applications due to its high adsorption on mineral surfaces (Sheng 2010). However, most of the currently used chemical EOR polymers are modified forms of polyacrylamide. Although polyacrylamide does not hydrolyze at room temperature, (Kurenkov et al., 2001), the pendant amide group present in polyacrylamide may undergo hydrolysis at elevated temperature and/or pH. Hydrolysis of polyacrylamide was observed by Muller in 1980. Hydrolyzed polyacrylamides suffer from thermal degradation at harsh reservoir conditions (Hazarika and Gogoi, 2020).



2.1. Materials

The coreflooding experiments that involved chemical injection necessitated the utilization of a combination of surfactant and polymer materials, along with samples of formation water, oil, and reservoir rock from the Khrisna Field. These components comprise as follows:

- The SS-B8020 type surfactant is water-soluble with a pH range of 5-8 and contains 50% active contents.
- The Polymer used was HBX 4785.
- The water used was taken from Tank-02.
- The water used was formation water from KH-217 well.
- The reservoir rock was taken from a core sample of well KH-217 at a depth of 1562.88 - 1563.70 m, which is composed of sandstone.

The surfactant used in the experiment is from the super surfactant (SS) series. This type of surfactant was chosen for its various advantages, including low concentration, salt tolerance, and emulsion, corrosion and scale reduction.

2.1.1. Low concentration

The application of Surfactant-Polymer Flooding to sandstone layers requires a high concentration of surfactants for effective results. However, this approach requires additional alkali to achieve extra Interfacial Tension (IFT). Whereas, high surfactant concentrations lead to a higher adsorption process. The use of a super surfactant presents a more economical alternative, as it only requires low concentrations to produce IFT as low as 10^{-2} mN/m, based on laboratory screening tests (Abrams, A, 1988; Ashayer, R *et al.* 2000; Berger, D *et al.* 2002).

When applied in limestone formations, adding sodium carbonate is recommended to reduce rock adsorption, but this does not affect the IFT change. The use of the Super Surfactant series is considered an economical option, as it only requires low concentrations ranging from 1000-3000 ppm. This concentration level is adequate to produce low enough IFT without the excessive use of alkali, which can cause corrosion and rock pore plugging (Ashayer, R *et al.* 2000; Berger, D *et al.* 2002; Kristanto, D *et al.* 2008; Kristanto, D, 2012).

2.1.2. Salt tolerance (Formation salt content)

The SS series of surfactants has been found to have high tolerance for salt content in formation water. Previous studies conducted by Berger, D *et al.* (2002) using this type of surfactant with ~110.000 ppm total dissolved solids (TDS) and around ~2500 ppm divalent cations demonstrated a significant reduction in interfacial tension (IFT), even at a low surfactant concentration of only 0.05%. Furthermore, the surfactant solution can be mixed with water without any prior treatment or softening, thereby resulting in a substantial reduction in costs (Wang, Z *et al.* 2001; Goddard, *et al.* 2004).

2.1.3. Emulsion, corrosion, and scale reduction

Emulsion, corrosion, and scale problems in formations can be prevented during treatment by using low concentrations of the treatment solution, without the need for alkali to generate additional ultra interfacial tension. (Wang, Z *et al.* 2001; Berger, D *et al.* 2002; Kristanto, D *et al.* 2008).

2.2. Coreflooding Test Stages

The coreflooding experiment involves injecting surfactant-polymer after the completion of the waterflooding stage (secondary recovery), as illustrated in Figure 2. The detailed chronological sequence of Surfactant-Polymer injection is as follows (Lemigas, 2012):

- Firstly, the core is re-saturated with formation water ($S_w = 100\%$).
- Oil is then injected into the core until no more water comes out (obtaining the initial oil saturation parameter - S_{oi} and connate water saturation - S_{wc}).
- Next, water is injected into the core and the resulting oil production is calculated (waterflooding stage).
- The water injection process is stopped once no more oil comes out of the core, and the residual oil saturation (S_{or}) and water saturation (S_w) parameters are obtained.

- Finally, Surfactant and Polymer are injected according to the established scenario, and the additional oil production is determined.

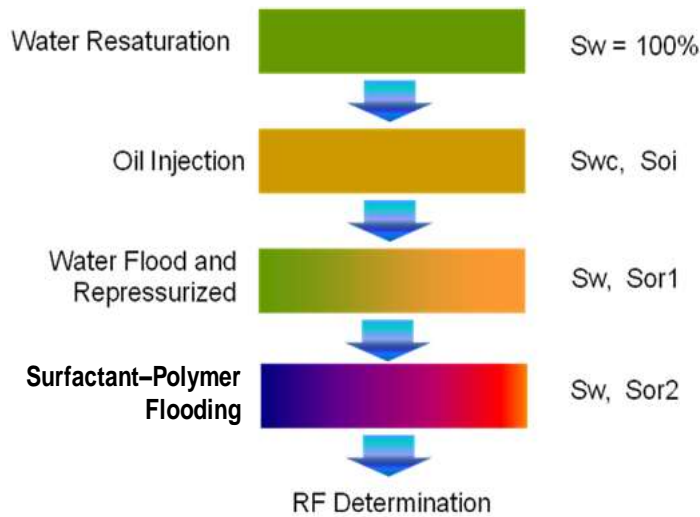


Fig. 2. Mechanism of coreflooding test in the laboratory (Lemigas, 2012)

RESULTS AND DISCUSSION

The laboratory study on surfactant-polymer injection for coreflooding tests involves several measurements, including the measurement of interfacial tension of surfactant solutions at different concentrations and field oils, evaluating polymer rheology, measuring physical properties of reservoir rocks, and conducting coreflooding tests.

3.1. Interfacial Tension Measurement

The Surfactant SS-B8020, it was dissolved in the formation water of KH-217 well at varying concentrations. A temperature resistance test was performed, and the results showed that surfactant was not degraded by the reservoir temperature (104,4 °C). The interfacial tension measurement results are presented in Figure 3 and Table 1.

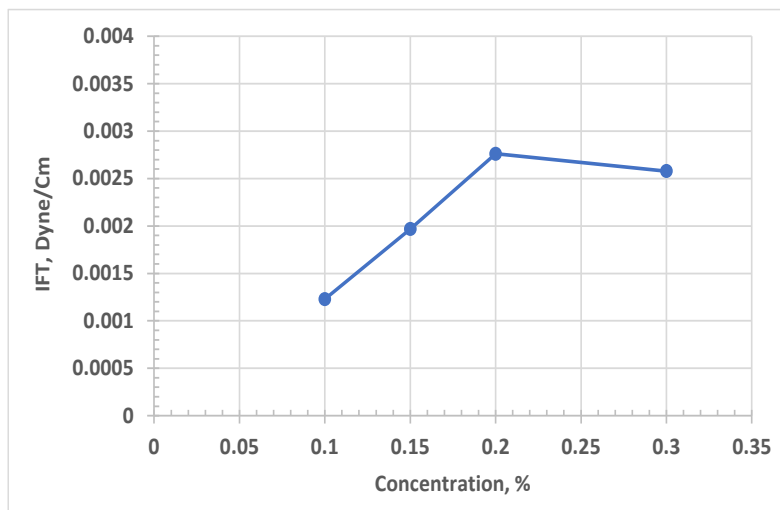


Fig. 3. Graph of interfacial tension measurement results

Table 1. Interfacial tension (IFT) measurement results

Surfactant	Concentration (%)	Diluting Water	Oil Sample	IFT, Dyne/cm
SS-B8020	0.10	KH-217	Tank-02	0.001381
				0.001230
				0.001130
SS-B8020	0.15	KH-217	Tank-02	0.001621
				0.001670
				0.001640
SS-B8020	0.20	KH-217	Tank-02	0.002852
				0.002761
				0.002815
SS-B8020	0.30	KH-217	Tank-02	0.002628
				0.002578
				0.002308

Based on the result in Figure 3 and Table 1, it is shown that with increasing surfactant concentration from 0.1% to 0.2% the interfacial tension was also increase. While, when the surfactant concentration increases to 0.3%, the interfacial tension was decrease, it is mean that the optimum of surfactant concentration is 0.2% and obtaining average interfacial tension is 0.002809 Dyne/cm. Furthermore, these optimum surfactant concentration of 0.2% then used for the laboratory experiments.

3.2. Result of Polymer Rheology Analysis

The HBX 4785 polymer is specifically designed for temperatures exceeding 100 °C. Along with rheology observations, a temperature resistance test was carried out to measure the polymer viscosity before and after being heated to 220 °F. The measurement results of polymer rheology i.e., viscosity and shear rate at 25 °C, 70 °C, 90 °C, and 104 °C are presented in Table 2. While, the correlation between shear rate and viscosity measurement results for different concentrations of polymer (ppm) are illustrated in Figures 4 through Figure 6.

Table 2. HBX 4785 Polymer Rheology

RPM	Shear Rate	25 °C	70 °C	90 °C	104 °C	PPM
6	7.92	36.5	20.7	18.5	15.78	1000
12	15.8	26.5	14.3	12.4	9.09	
30	39.6	17.9	9.4	8.65	7.06	
60	79.2	14.2	7.15	6.02	4.85	
100	132	11.3	6	4.91	4.10	
120	158	10.3	5.56	4.18	3.58	
6	7.92	39.7	28.7	20.5	14.05	1100
12	15.8	29.4	18.8	14.6	11.24	
30	39.6	21.2	11.7	10.3	8.69	
60	79.2	16	9	6.37	4.74	
100	132	13.5	7.22	5.6	4.13	
120	158	12.2	6.49	4.44	2.60	
6	7.92	41	31	22.5	15.27	1200
12	15.8	31.2	21.3	16	13.03	
30	39.6	22	13.8	11.65	10.54	
60	79.2	17	10.3	7.97	6.82	
100	132	14	8.45	6.56	5.62	
120	158	13	7.31	5.75	5.00	

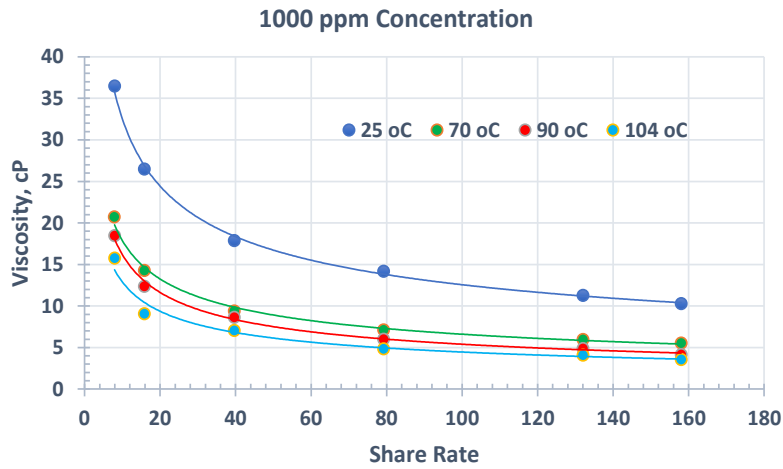


Fig. 4. Viscosity of HBX 4785 polymer at a concentration of 1000 ppm

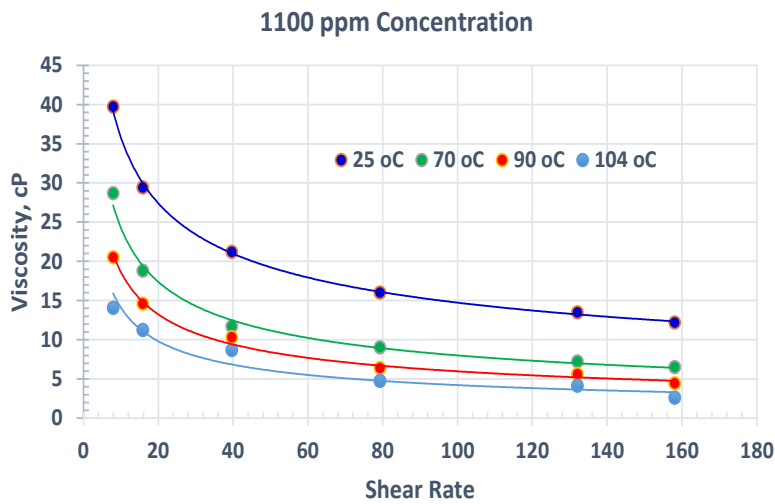


Fig. 5. Viscosity of HBX 4785 polymer at a concentration of 1100 ppm

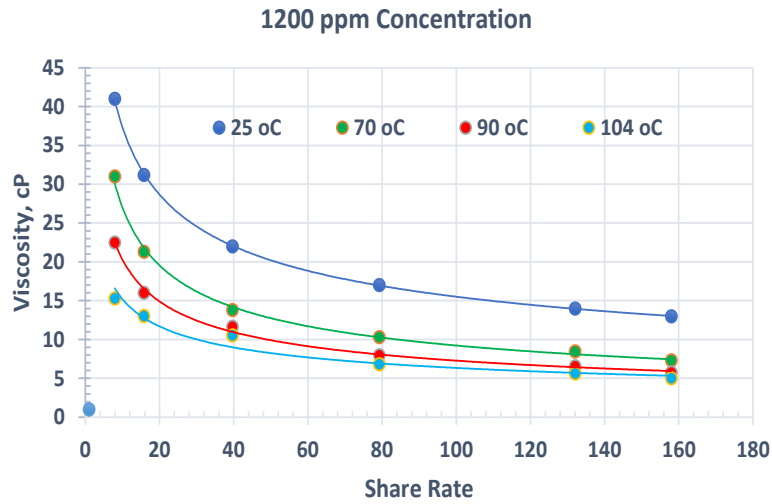


Fig. 6. Viscosity of HBX 4785 polymer at a concentration of 1200 ppm

3.3. Result of Oil Sample Analysis

The oil samples were measured for viscosity and torque at various temperatures, including the reservoir temperature i.e. from 70 °C through 104.4 °C. The measurement results of oil samples are presented in Table 3 and Figure 7.

Table 3. Results of oil viscosity and torque measurement

RPM	Shear Rate	70 °C		90 °C		104 °C	
		Visc. (cp)	Torque (%)	Visc. (cp)	Torque (%)	Visc. (cp)	Torque (%)
6	7.92	9.3	1.9	2.8	0.5	3.75	0.8
12	15.8	7.4	2.8	3.2	1.2	2.4	1.8
30	39.6	6.6	6.6	3.7	3.7	3.15	3.2
60	79.2	6.1	12.1	3.65	7.4	3.08	6.1
100	132	6.09	20.4	3.82	12.7	3.30	11
120	158	6.09	24.3	3.84	15.3	3.24	13

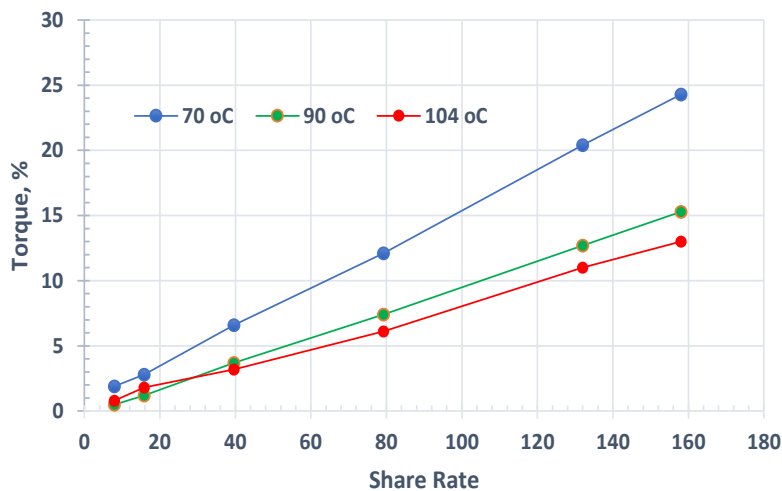


Fig. 7. Relationship between share rate versus torque at a various temperature

3.4. Measurement of Physical Properties of Core Plug

The core samples were drilled to produce core plugs with a length of approximately 3 inches and a diameter of 1.5 inches. Two samples core plugs were used in the experiment, and the petrophysical properties of the core data is presented in Table 4.

Table 4. Petrophysical core properties

Core No.	Length (cm)	Diameter (cm)	Bulk Volume (cc)	Grain Volume (cc)	Pore Volume (cc)	Porosity (%)	Gas Permeability (mD)
1	8.052	3.834	92.960	72.196	20.764	22.34	2405.00
2	7.385	3.828	85.027	63.6	21.427	25.20	1653.17

3.5. Results of Coreflooding Test-1

In this study, a chemical injection scenario was designed to inject 1000 ppm Surfactant at 0.3 pore volume, followed by 1200 ppm Polymer at 0.3 pore volume. The process was repeated with 1500 ppm Surfactant at 0.3 pore volume and 1200 ppm Polymer at 0.3 pore volume. However, the results of the repeated injection on Core No. 1 showed poor performance. The reason behind this was the insufficient concentration of surfactant used, which was not optimal for inducing the desired changes in the physical properties of the rock and reservoir fluid, as well as the recovery factor. The injection results of Coreflooding test-1 have been presented in chronological order in Figure 8, while complete experimental data and results are shown in Table 5 and Table 6.

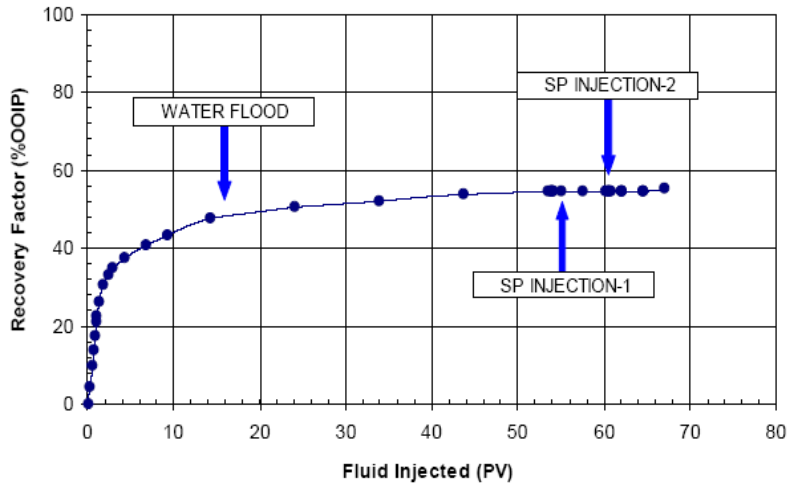


Fig. 8. Coreflooding test-1 results

Table 5. Changes of rock properties coreflooding-1

Core No.	Ka (mD)	Kw (mD)	Ko@Swc (mD)	Kw@Sor1 (mD)	Kw@Sor2 (mD)
1	2405.00	614.35	325.68	62.64	30.29

Table 6. Coreflooding test-1 results

Core No.	OOIP (cc)	RF Waterflood		RF Chemical Flood-1		RF Chemical Flood-2	
		(cc)	(%)	(cc)	(%)	(cc)	(%)
1	10.85	5.90	54.39	0.00	0.00	0.09	0.80

3.6. Results of Coreflooding Test-2

To improve the injection results, modifications were made by increasing the surfactant concentration to 3000 ppm at 0.3 pore volume, followed by injection of Polymer at 1000 ppm and 0.2 pore volume. This injection process resulted in an increase of 12.89% OOIP in the recovery factor. The injection and water cut results are shown in Figure 9, while the complete data and result of coreflooding test-2 are presented in Table 7 and Table 8.

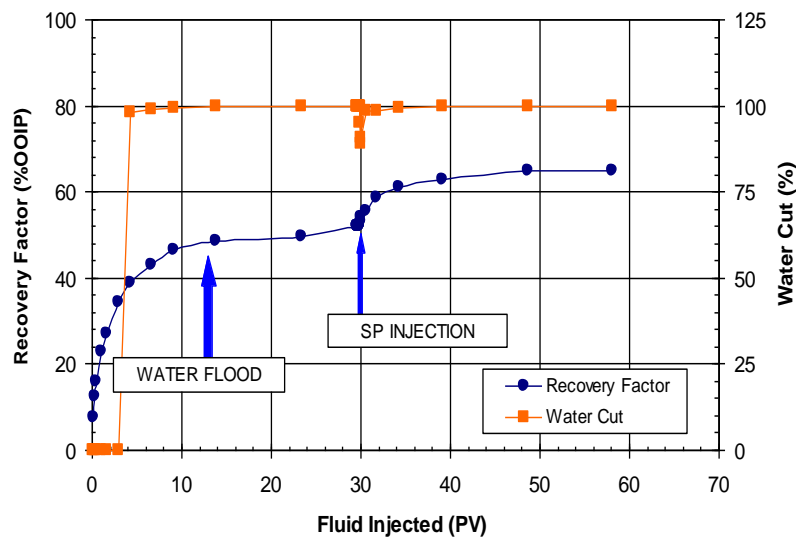


Fig. 9. Recovery factor and water cut of coreflooding test-2 results

Table 7. Changes of rock properties coreflooding-2

Core No.	Ka (mD)	Kw (mD)	Ko@Swc (mD)	Kw@Sor1 (mD)	Kw@Sor2 (mD)
2	1653.17	276.77	198.08	61.51	27.68

Table 8. Coreflooding test-2 results

Core No.	OOIP (cc)	RF Waterflood		RF Chemical Flood	
		(cc)	(%)	(cc)	(%)
2	11.63	6.44	56.38	1.50	12.89

3.7. Surfactant Condition After Coreflooding Test

After being used for coreflooding tests at various concentrations (0.1-0.3%), the Surfactant SS B8020 solution was collected back into a glass beaker and left undisturbed for 7 (seven) days at reservoir temperature conditions to observe any changes in its physical condition. From the observations, it was found that the Surfactant SS B8020 solution did not change colour (remained clear) and remained relatively the same as before being injected into the core plug. No particle precipitation occurred, as shown in Figures 10 and Figure 11. This indicates that Surfactant SS B8020 is compatible and did not cause plugging in the pore spaces of the core plug (reservoir rock).

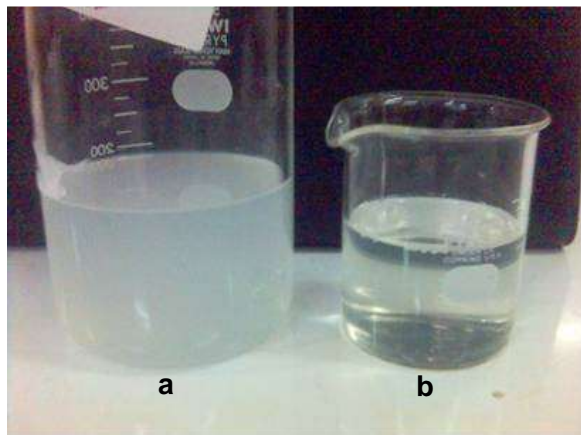


Fig. 10. Comparison of Surfactant SS B8020 at 0.3% concentration (b) with other types of surfactants (a)



Fig. 11. Surfactant SS B8020 at concentrations of 0.1-0.2% after coreflooding test-2

CONCLUSIONS

The following conclusions are drawn from the comprehensive analysis and discussion:

1. The Surfactant SS-B8020 when dissolved in the formation water has optimum concentration is 0.2% and obtaining average interfacial tension is 0.002809 Dyne/cm.
2. The measurement results of surfactant and polymer properties showed good outcomes as injection materials for enhanced oil recovery.
3. Injecting surfactant-polymer at concentrations of 3000 ppm and 1000 ppm, respectively, with a 0.3 pore volume and 0.2 pore volume, resulted in an enhancement of oil recovery by 12.89%.
4. The utilization of surfactant SS B8020 as an injection fluid did not result in any pore plugging in the reservoir rock, it means that the injection fluid was compatible with the reservoir rock and could be avoided a reservoir problem.
5. The findings of this study can serve as a valuable reference for practical application in the field, using either the huff and puff (soaking) method or through pilot project and full-scale approaches.

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DECLARATION OF COMPETING INTEREST

The authors have no conflict of interest to declare.

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