ORIGINAL PAPER - PRODUCTION ENGINEERING

Effect of viscosity and interfacial tension of surfactant–polymer flooding on oil recovery in high-temperature and high-salinity reservoirs

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Abstract This study aims to analyze the influence of viscosity and interfacial tension (IFT) on oil displacement efficiency in heterogeneous reservoirs. Measurement of changes in polymer viscosity and IFT indicates that viscosity is influenced by brine salinity and shearing of pore media and that IFT is influenced by salinity and the interaction between the polymer and surfactant. High concentrations (2,500 and 3,000 mg/L) of polymer GLP-85 are utilized to reduce the effect of salinity and maintain high viscosity (24 mPa s) in formation water. After shearing of pore media, polymer viscosity is still high (17 mPa·s). The same polymer viscosity (17 mPa·s) is utilized to displace oil, whose viscosity is 68 mPa·s, at high temperature and high pressure. The IFTs between surfactant DWS of 0.2 % in the reservoir water of different salinities and crude oil droplet are all below 10^{-2} mN/m, with only a slight difference. Surfactant DWS exhibits good salt tolerance. In the surfactant–polymer (SP) system, the polymer solution prolongs the time to reach ultra-low IFT. However, the surfactant only has a slight effect on the viscosity of the SP system. SP slugs are injected after water flooding in the heterogeneous core flooding experiments. Recovery is improved by 4.93–21.02 % of the original oil in place. Furthermore, the core flooding experiments show that the pole of lowering the mobility ratio is more significant than decreasing the IFT of the displacing agent; both of them must be optimized by considering the injectivity of the polymer molecular, emulsification of oil, and the economic cost. This study provides technical support in selecting and optimizing SP systems for chemical flooding.

Keywords Chemical flooding · Viscosity · Interfacial tension · Oil displacement efficiency · Salinity

Abbreviations
IFT	Interfacial tension, mN/m
GLP-85	The polymer, modified polyacrylamides, whose relative molecular mass is 1.75×10^7
OOIP	Original oil in place
EOR	Enhanced oil recovery
SP	Surfactant–polymer
ASP	Alkali–surfactant–polymer
DWS	The surfactant, an anionic sulfate, whose average relative molecular weight is 560 to 600
PV	Injection pore volume
CMC	Critical micelle concentration

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Introduction

Polymer flooding has been employed successfully in Daqing Oilfield in China for decades; it contributed to the oil recovery of more than 10 % of original oil in place (OOIP) after water flooding (Wang et al. 2009).

Alkaline–surfactant–polymer (ASP) flooding can effectively reduce oil residual saturation to reduce interfacial tension (IFT) and the mobility ratio between the water phase and oil phase (Clark et al. 1988; Meyers et al. 1992; Vargo et al. 1999). Alkali is added in ASP flooding to decrease the quantity of the surfactant through competitive adsorption with the surfactant and reaction with petroleum acids in crude oil to generate a new surfactant (Pope 2007; Rivas et al. 1997). However, the use of alkali has introduced problems in the injection of the ASP solution These problems include the deposition of alkali scales in the reservoir and bottom hole (Hou et al. 2005; Batawee and Nasr-El-Din 2011; Jing et al. 2013), difficulty of treating the produced water (Deng et al. 2002), and reduction of the viscosity of the combined ASP slug (Wang et al. 2006; Nasr–El–Din H.A. et al. Nasr-El-Din et al. 1992). Many methods were introduced to solve these problems. Elraies (2012) proposed a new polymeric surfactant and conducted a series of experiments to evaluate this surfactant in the absence and presence of alkali. Some studies (Maolei and Yunhong 2012; Flaaten et al. 2008; Berger and Lee 2006 replaced strong alkalis with weak alkalis, such as sodium carbonate, sodium metaborate, and organic alkaline, to reduce their effect on the viscosity of the ASP slug. Alkali-free SP flooding avoids the drawbacks associated with alkali. Surfactants with concentrations higher than the critical micelle concentration (CMC) can achieve ultra-low IFT. However, such surfactants are expensive. The use of a hydrophilic surfactant mixed with a relatively lipophilic surfactant or a new surfactant was also investigated (Rosen et al. 2005; Aoudia et al. 2006; Cui et al. 2012). However, studies on SP flooding only focused on the screening and evaluation of the polymer and surfactant and their interaction. Reduction in mobility ratio and IFT is influenced by reservoir brine salinity, reservoir temperature, concentration of chemical ingredients and oil components, and others (Gaonkar 1992; Ferdous et al. 2012; Liu et al. 2008; Gong et al. 2009; Cao et al. 2012; Zhang et al. 2012). Displacement performance is affected by the interaction of the physical properties of the reservoir and those of the fluid. The primary influencing factors must be identified. SP flooding can enhance recovery because of its capability to control viscous fingering and reduce IFT. In formulas involving the capillary number, ultra-low IFT between the binary system and oil drop in a homogenous core yields the lowest residual oil saturation and the highest oil recovery. In a heterogeneous core with high permeability, sweep efficiency has a larger influence on oil recovery than displacement efficiency. Highest oil recovery can be achieved under optimum IFT and not under the lowest IFT of the binary system. However, this concept (Wang et al. 2010) is based on light oil reservoir with high permeability and low temperature. Dagang Oilfield is a reservoir with medium–low permeability characterized by high temperature, significant heterogeneity, and high brine salinity. These rough conditions bring about a significant challenge in SP flooding and demand different IFTs and viscosities of the SP system.

Based on the reservoir condition of Dagang Oilfield, static experiments were conducted to study the influence of loss parameters of viscosity and IFT on the SP system. Combined with core flooding, the respective effect of viscosity and IFT in the binary system on displacement efficiency was investigated. The results of this study provide insights into chemical screening, slug optimization, and injection methods in the field.

Equipment and materials

Equipment

The main equipment for the experimental flow is shown in Fig. 1. The heterogeneous core holder is 30 cm long. The core flooding model is 30 cm long, 4.5 cm wide, and 4.5 cm thick. Each layer of the model is 1.5 cm thick. Other equipment include a RheoStress 6,000 rheometer from HAAKE, a Brookfield DV-II + viscosimeter, several high-pressure intermediate containers, an automatic measuring cylinder, a thermostat oven, a pressure collection system, and a constant flow pump. Water was pumped into high-pressure intermediate containers at a certain speed, and formation water and crude oil were forced into the core with a certain difference in pressure. A 30 cm long core holder was utilized to hold the core with external pressure that is 1–2 MPa more than the inlet pressure. The pressure was determined by a pressure collection system. An oven was utilized to maintain stable experimental temperature. The product was gathered and measured by a product acquisition system.

Materials

The brine (experimental water) was composed of simulated pure water, formation water, and simulated formation water. The ion concentrations of these components are listed in Table 1. A three-layer artificial heterogeneous sandstone core was created. The core has an average permeability ranging from 55.38×10^{-3} to 106.00×10^{-3} μm^2 and a porosity percentage of 24.2 %. All other parameters of the core are shown in Table 2.

Modified polyacrylamide GLP-85 was utilized as the polymer. This polymer, whose relative molecular mass is 1.75×10^7, has a high tolerance for salinity. The viscosity of the polymer was measured with HAAKE Rotational Rheometer-6000 at 78 °C.
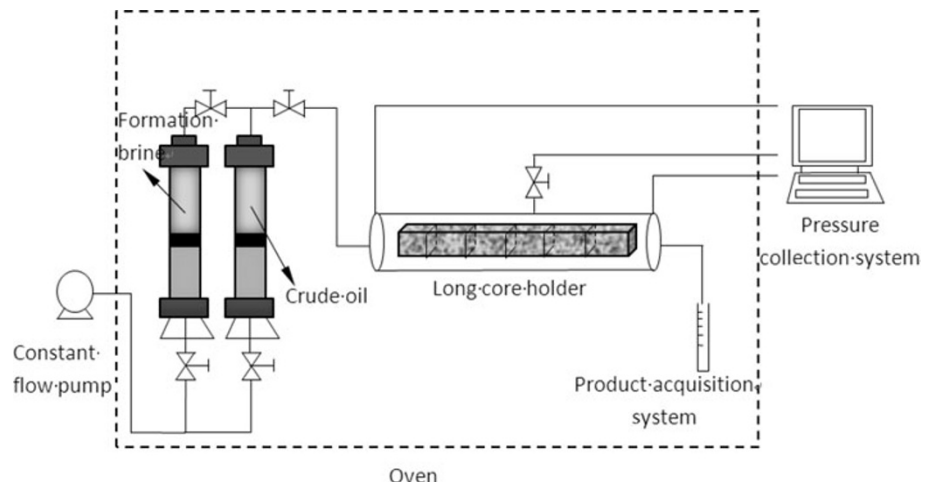
Fig. 1 Main experimental setup

Table 1 Ion concentration of simulated injection water and formation water (mg/L)

Water type	$Na^+ + K^+$	Ca^{2+}	Mg^{2+}	Cl^-	HCO_3^-	Total salinity
Simulation injection water	38	18	55	53	285	452
Formation water	9,423	40	430	9,485	623	20,001
Simulated formation water	10,993	52	563	17,739	605	29,952

Table 2 Core parameters and oil displacement efficiency of chemical flooding

Core Number	Porosity/ %	Permeability/ 10^{-3} μm^2	0.3 PV chemical system	Reduction in water cut/ %	Water drive/ % OOIP	Increase in recovery/ % OOIP	Total recovery/ % OOIP
DG-F4	18.51	55.38	0.2 % DWS	4.41	47.76	4.93	52.69
DG-F15	27.42	67.77	2,000 mg/L GLP-85 + 0.08 % DWS	29.58	49.63	10.48	60.12
DG-F13	27.26	65.24	2,000 mg/L GLP-85 + 0.2 % DWS	19.67	48.04	18.69	66.72
DG-F14	26.78	81.07	2,000 mg/L GLP-85 + 0.3 % DWS	39.18	54.31	14.71	69.01
DG-F11	25.86	77.25	2,500 mg/L GLP-85 + 0.2 % DWS	58	49.81	21.02	70.83
DG-F16	27.82	96.11	2,500 mg/L GLP-85 + 0.2 % DWS after shearing	4.78	50.21	3.57	53.78

When the water cut was 98 %, water flooding was ceased and the SP system was injected. The increase in recovery was observed in the stage of injecting SP system and subsequent water flooding. Total recovery includes the recovery of water flooding and the increase in recovery

The main active material of surfactant DWS is an anionic sulfonate component, of which 50 wt % is active content, 16.8 wt % is unsulfonated oil, 31.2 wt % is volatile content, and 2.0 wt % is inorganic salt. The average relative molecular weight ranges from 560 to 600.

The polymer (2,000 and 2,500 mg/L) and the surfactant (0.08–0.3 wt %) were mixed with formation water to form the SP system (binary system). Ground dehydration degassed oil and kerosene were mixed at a volume ratio of 5–1 to maintain consistent viscosity between the simulated oil and the crude oil in the reservoir. The viscosity of oil is 68 mPa·s at 78 °C. A constant reservoir temperature of 78 °C was maintained throughout the experiment. Table 3

shows the reservoir condition and the basic characteristics of the pore fluid.

Viscosity and IFT measurement

The viscosities of the SP solutions were determined at a shear rate of 7.34 s^{-1} with HAAKE Rotational Rheometer-6000 at 78 °C. The IFTs between the surfactant solutions and oil were measured at 78 °C with a spinning drop tension meter (Model Texas-500). The spinning oil droplet was stretched in the chemical agent solution until the oil/water phase reached equilibrium at a rotation speed of 6,000 r/min. The images were stored at regular intervals. In

Table 3 Reservoir condition and crude oil properties

Item	Permeability/10^{-3} μm^2	Porosity/ %	Variation coefficient of permeability	Reservoir temperature/ °C
Reservoir condition	55.38–106.00	24.2	0.6	78
Item	Reservoir depth (m)	Formation water type	Crude oil viscosity/(mPa·s)	Crude oil density/(g/cm^3)
Reservoir condition	2,100–2,300	MgCl$_2$	68 (at 78 °C)	0.922–0.968 (on the ground)

the images, the height of the spinning oil drop was measured to calculate the IFT when the ratio of the length to the height of oil drop was more than 4. However, length and height should be measured only when the ratio of the length to the height of the oil drop is between 1 and 4. The IFTs of the different concentrations of the surfactant were obtained with the abovementioned surfactants or their mixtures with a polymer.

Core flooding experiments

1. The heterogeneous core was vacuumized and saturated with formation water. Pore volume was then measured.
2. The model was saturated with crude oil at an injection rate of 0.2 mL/min. Original oil saturation and irreducible water saturation were then calculated.
3. Formation water was injected at a rate of 1.2 mL/min until the water cut reached 98 %. The produced oil and water and pressure change in the inlet were monitored.
4. An SP system solution of 0.3 PV was injected at a rate of 1.2 mL/min. Water flooding was performed at the same rate until the water cut reached 98 %. Ultimate recovery was then calculated.

Results and discussion

Influencing factors of binary system's performance

Polymer

The polymer solutions were generally fabricated with pure water in chemical flooding, thereby reducing the influence of salinity on the polymer mother solution. The solution was diluted with reservoir water to guarantee that the chemical system matched the formation water with high salinity. Polymer viscosity was measured in high salinity under constant temperature because salinity affects the viscosity and IFT of the binary system. The viscosity of the polymer solution must be determined to displace the crude oil with high viscosity. Therefore, the polymer solution with a high concentration was utilized. Polymer solutions of different concentrations were fabricated with a formation brine of different salinities at 78 °C. The results of viscosity changes are shown in Table 4.

As shown in Table 4, the viscosity of the polymer solution decreased sharply with the increase in salinity when the polymer concentration was determined. When the polymer concentration was 1,500 mg/L, the viscosity of the polymer solution decreased from 29 to 8 mPa·s, and the viscosity retention rate was 27.59 %. However, when the polymer concentration was 3,000 mg/L, the viscosity of the polymer solution decreased from 172 to 25 mPa·s, and the viscosity retention rate was 14.53 %. The viscosity retention rate decreased and the loss of polymer solution increased with the increase in polymer concentration. With the increase in salinity, the polymer molecular chain became compressed that it could not interweave with another polymer molecular chain. In addition, a small molecular group was formed. The viscous force among the polymer molecules was reduced after the group was formed, resulting in the loss of viscosity of the polymer solution. However, viscosity increased in each style of formation water with the increase in polymer solution. High concentration of the polymer solution was necessary to maintain high velocity. Thus, 2,500 mg/L was determined based on the polymer's injectivity, economic cost, and the demand of viscosity.

The polymer solution had to flow through pumps, pipes, valves, perforated holes, and so on at a high speed before it was injected. To simulate the effect of mechanical shearing on viscosity, 2,500 and 3,000 mg/L of the polymer solution were dissolved with formation water and simulated formation water and sheared in a Waring device at a speed of 3,000 r/min for 20 s. The viscosities were measured before and after shearing at 78 °C. The results are shown in Table 5.

As shown in Table 5, the viscosity retention rates at 2,500 and 3,000 mg/L of the polymer solution were 70.83 and 66.67 % in formation water, respectively, and 86.67 and 76 % in simulated formation water, respectively, after shearing. Therefore, this type of polymer solution dissolved with high salinity of brine has a strong ability to resist shearing. This finding indicates that the solution can be applied in the reservoir.

Surfactant

The mixture of surfactant and polymer solution injected into the formation is affected by many factors, such as temperature, salinity, shearing, retention, adsorption, and dilution of formation brine. Therefore, surfactant DWS was

Table 4 Viscosity change in polymer GLP-85 with different salinities of water

Polymer concentration (mg/L)	Simulation pure water (salinity of 452 mg/L) Viscosity/(mPa·s)	Formation water (salinity of 20,000 mg/L) Viscosity/(mPa·s)	Simulated formation water (salinity of 29,952 mg/L) Viscosity/(mPa·s)
4,000	–	–	73
3,500	–	–	50
3,000	172	48	25
2,500	79	24	15
2,000	50	17	13
1,500	29	9	8

Table 5 Viscosity change in polymer GLP-85 before and after shearing

Polymer concentration/ (mg/L)	Viscosity/(mPa·s)			
	Formation water (salinity of 20,000 mg/L)		Simulated formation water (salinity of 29,952 mg/L)	
	Before shearing	After shearing	Before shearing	After shearing
2,500	24	17	15	13
3,000	48	32	25	19

Fig. 2 IFTs between DWS of different concentrations and crude oil

utilized to create solutions of different concentrations at reservoir temperature. The IFTs were measured, and the results are shown in Fig. 1.

As shown in Fig. 2, IFT between the oil droplet and the solution decreased gradually when the surfactant concentration increased from 0.05 to 0.4 %. IFT reached an ultra-low level when the concentration was 0.3 %. With the increase in surfactant concentration, the surfactant molecules were adsorbed onto the oil/water interface constantly with the hydrophilic in the water phase and lipophilic in the oil phase. When the concentration was more than 0.3 %, the adsorption on the oil/water interface reached saturation, and IFT remained stable. Thus, the concentration of 0.3 % was the CMC. Surfactant concentration of 0.2–0.3 % should be selected because of its economic cost and loss in the pore media.

The process of dissolving the surfactant with pure water and diluting it with formation water would seriously influence the activity of the surfactant. Given that the salinity of the injected water was lower than that of the original formation water, the salinity of the areas washed for long-term water flooding was reduced, whereas that of the unwashed areas remained high. In SP system flooding, the mobility control of the polymer solution causes the chemical system to flow toward the area unwashed with water. As a result,
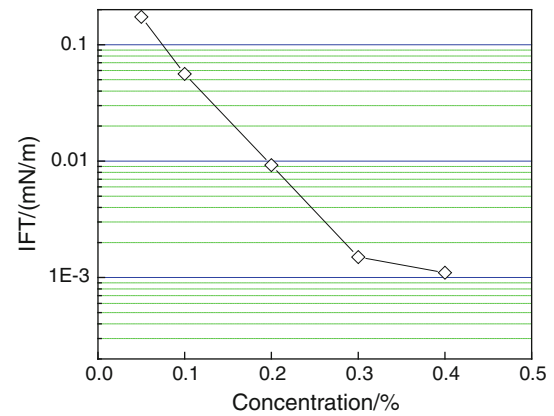
the chemicals are placed in contact with the original formation water and are affected by salinity. Therefore, studying the influence of salinity on IFT is essential. Figure 3 shows the influence of different salinities on IFT between the DWS of 0.2 % and the crude oil droplet. With increasing salinity, the IFTs of all types of brine can reach an ultra-low level. However, the prolonged time of reaching ultra-low IFT would affect the time of chemical flooding in the marine oilfield. With constant time, the increase in salinity can increase IFT. The reason for such is that the surfactant molecules adsorbed on the oil/water interface desorbed constantly and entered into the oil phase with the increase in salinity, especially from several hundred to 30,000 mg/L. However, ultra-low IFTs were reached with different salinities, indicating that 0.2 % surfactant can adapt to the reservoir with different salinities.

The compatibility between the polymer and surfactant in the SP system had an interaction problem. We analyzed the interaction by studying how the addition of surfactant DWS influences the viscosity of polymer and how the addition of a polymer solution affects the IFT of the surfactant. Table 6 shows the effect of the addition of surfactant on polymer viscosity. Table 7 shows the effect of the addition of polymer solution on the IFT of the surfactant. Tables 6 and 7 show that ultra-low IFT can be reached by 0.2 % DWS surfactant with the increase in the concentration of the polymer solution. However, longer time was required. The velocity of the surfactant molecules to the oil/water phase decreased because of the long organic chains of polymer molecules. Therefore, more migration time was required. The SP system can reach ultra-low IFT with longer interfacial contacting time, which matches the SP system flooding. The flowing velocity of the SP system in the reservoir was much slower because the mobility of the SP system was smaller than that of a single surfactant solution. Therefore, contact time with crude oil was longer, thereby reducing oil–water IFT and enhancing oil displacement efficiency. However, the surfactant did not
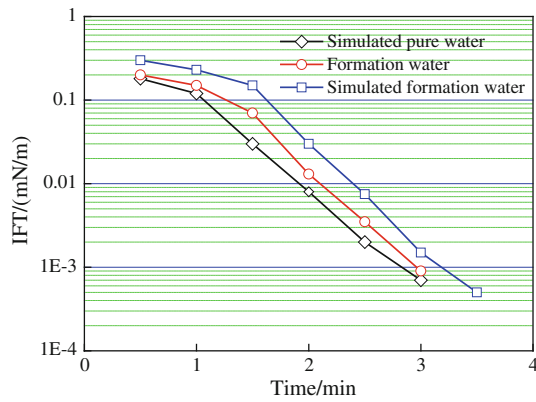
Fig. 3 IFTs between water-prepared DWS solution of different salinities and crude oil

significantly affect the viscosity of the SP system; it merely affected dilution. Therefore, the SP solution has the same tackifying property as that of the polymer solution at the same concentration. It also allowed for the reduction of IFT with prolonged contact time. Surfactant concentration should be increased and polymer concentration should be decreased to reduce IFT instantly and achieve instant emulsification, given that a certain relationship exists between emulsification and IFT reduction. However, such procedures are expensive and lead to less activity of tackifying and poor ability of the SP system to control mobility ratio. The surfactant and polymer can be mixed to prolong contact time with the crude oil; such would be a significant contribution to the study of injection patterns in chemical flooding after water flooding.

Effect of viscosity on oil displacement

Table 2 shows the results of core displacement of various chemical systems. Compared with the oil displacement

results of DG-F4, DG-F13, and DG-F11, the viscosity of the SP system increased gradually and the recovery of flooding was enhanced on the condition of similar oil recovery of water flooding at a certain surfactant concentration and with increasing polymer concentration. Based on the change in pressure curve and water cut curve, the increase in the system's viscosity increased the flowing resistance of the water phase in the high-permeable layer. As a result, the pressure on the entry side increased gradually. The SP system flowed into the middle- and low-permeable layers where residual oil was abundant, and the water cut significantly decreased. When the system viscosity increased from 1 to 15 mPa·s, oil recovery increased by 13.76 %. When the viscosity increased from 15 to 22.5 mPa·s, enhanced recovery increased only by 2.33 %. However, the pressure gradient on the entry side increased from 11.05 to 15.23 MPa/m, indicating that viscosity contributed 73.62 % to the increase in oil recovery and that the proportion declined with the increase in viscosity. Thus, oil recovery did not increase when viscosity increased (Fig. 4).

The SP system (2,500 mg/L GLP-85 + 0.2 % DWS) was sheared in the Waring device and then utilized to displace residual oil in heterogeneous cores. Figure 5 shows the dynamic change in recovery before and after shearing. The displacement results of core DG-F11 and DG-F16 showed that viscosity changed greatly after shearing and that recovery declined sharply correspondingly. Recovery after shearing was 53.78 % OOIP and only increased by 3.57 % OOIP after water flooding. The water cut was reduced only by 4.78 %. However, recovery before shearing was 70.83 % OOIP and increased by 21.02 % OOIP after water flooding. The water cut was reduced by 58 % before shearing. The pole of lowering the mobility ratio was obvious in the heterogeneous cores.

Table 6 Changes in SP system viscosity with surfactant concentration

Polymer concentration/(mg/L)	Viscosity/(mPa·s)			
	0 %DWS + GLP-85	0.1 %DWS + GLP-85	0.2 %DWS + GLP-85	0.3 %DWS + GLP-85
2,000	17	16.5	15	14
2,500	24	23	22.5	21

Table 7 IFT of the SP system changes with polymer concentration

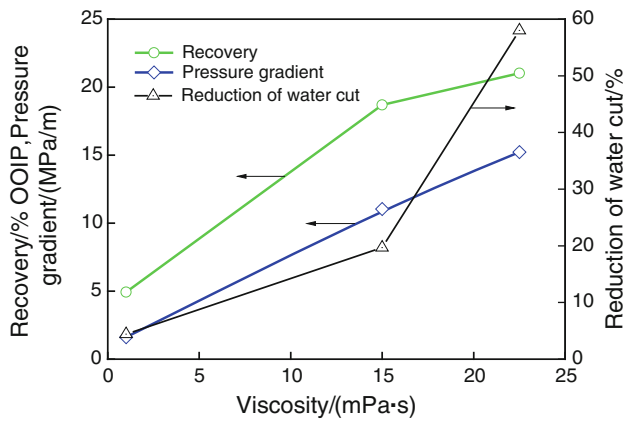| Surfactant concentration/ %	DWS		2,000 mg/L GLP-85 + DWS		2,500 mg/L GLP-85 + DWS	
	t/min	$\sigma/(10^{-3}\text{mN/m})$	t/min	$\sigma/(10^{-3}\text{mN/m})$	t/min	$\sigma/(10^{-3}\text{mN/m})$
0.2	3	5.31	6.5	9.23	12	12.15

Fig. 4 Relationship among enhanced recovery, maximum pressure gradient, reduction of water cut, and viscosity
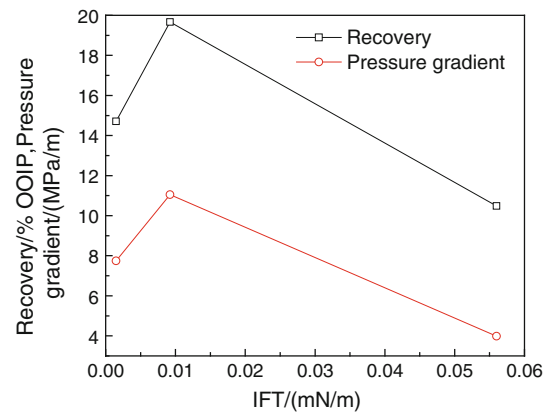

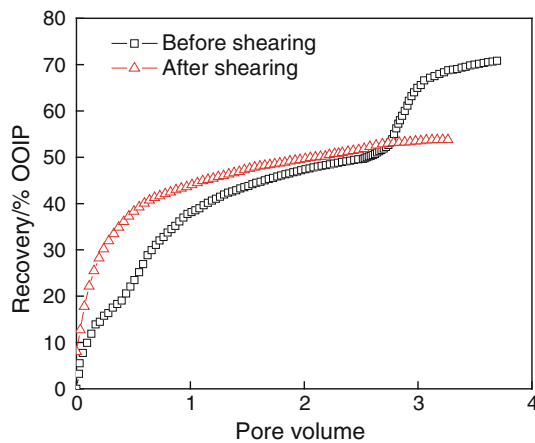Fig. 6 Relationship between IFT and recovery and between IFT and pressure gradient

Fig. 5 Flooding performance of different viscosities of binary systems

Influence of IFT on oil recovery

Surfactants of different concentrations were added to the polymer with a concentration of 2,000 mg/L. Core displacement experiments were conducted with the mixtures. Compared with core DG-F13, DG-F14, and DG-F15, IFT decreased from 5.6×10^{-2} to 1.5×10^{-3} mN/m when the surfactant concentration increased from 0.08 to 0.3 % under constant system viscosity (Table 2). Recovery increased from 10.4 to 14.71 % OOIP after water flooding. Errors in the oil displacement experiment of core DG-F14 might have caused the different results. However, we can still consider the contribution of IFT to the recovery of heterogeneous cores, ranging from 4 to 8 % OOIP, which only accounts for approximately 30 %; this percentage is less than the pole of lowering the mobility ratio, which is nearly 70 %. Therefore, control of mobility between oil and water in the heterogeneous cores and increase in the displacement resistance of high-permeable layers should be

considered first. The increase in the recovery of reducing IFT was much less than that of increasing viscosity. Figure 6 shows the relationship between IFT and recovery as well as that between IFT and the pressure gradient. With the decrease in IFT, recovery initially increased and then decreased. Therefore, other principles could have increased recovery other than the decrease in IFT. By changing pressure, oil–water emulsification was strengthened because of the decrease in IFT from 5.6×10^{-2} to 9.23×10^{-3} mN/m. Moreover, the emulsified oil exhibited coalescence, which increased the displacement resistance, formed an oil block, and significantly increased the pressure gradient. The low IFT of 1.5×10^{-3} mN/m made oil-in-water emulsion stable. Thus, the oil block was not formed easily.

Conclusions

Polymer viscosity was seriously affected by salinity. The effect of shearing on polymer viscosity and oil recovery was significant. Thus, high concentration of polymer was utilized to maintain high viscosity. The CMC of DWS was 0.3 %; this CMC value was employed to maintain low IFT. The IFTs with the brine at all salinity levels could be ultra low, indicating that salinity only had a slight effect on the activity of 0.2 % DWS. The time of reaching ultra-low IFT between the oil droplet and SP system was longer than that of a single surfactant because of the polymer's existence. The injection pattern of the surfactant and polymer mixture was used to maintain low IFT in the binary system. In the core whose permeability contrast was 4 and average permeability ranged from 55.38×10^{-3} to 106.00×10^{-3} μm^2, viscosity and IFT contributed approximately 70 and 30 % to the increase in oil recovery, respectively. In the heterogeneous, heavy oil reservoirs whose permeability contrast was 4 and temperature was 78 °C, increasing

displacement resistance in the high-permeable layers and displacing the residual oil caused by microheterogeneity are important to improve oil recovery. When screening the properties of agents in chemical flooding, viscoelasticity is the first thing that should be considered. The second is how to reach ultra-low IFT between oil and water. Viscosity and IFT must be optimized to maximize oil recovery in the heterogeneous cores on the condition that the injectivity and emulsification of the SP system are considered. When viscosity is high, injectivity becomes a problem. When IFT reaches an ultra-low level, oil-in-water emulsion remains stable, and the coalescence of emulsified oil droplet would not easily occur. Finally, an oil block would be formed.

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