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Research Article

Main Controlling Factor of Polymer-Surfactant Flooding to Improve Recovery in Heterogeneous Reservoir

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This study aims to analyze the influence of viscosity and interfacial tension (IFT) on the recovery in heterogeneous reservoir and determines the main controlling factors of the polymer-surfactant (SP) flooding. The influence of the salinity and shearing action on the polymer viscosity and effects of the surfactant concentration on the IFT and emulsion behavior between chemical agent and oil were studied through the static and flooding experiments. The results show that increasing the concentration of polymer GF-11 (HPAM) can reduce the influence of the salinity and GF-11 has high shear-resistance property. In the condition of the Jilin Oilfield, the oil/water IFT can reach 10^{-3} mN/m when the surfactant concentration is 0.3 wt%. The lower the IFT is, the easier the emulsion of SP and oil is formed. Seven flooding experiments are conducted with the SP system. The results show that the recovery can be improved for 5.02%–15.98% under the synergistic effect of the polymer and surfactant. In the heterogeneous reservoir, the contribution of oil recovery is less than that of the sweep volume.

1. Introduction

Polymer can increase the viscosity of injected fluid, decrease the mobility ratio of water and oil, and then expand the sweep coefficient [1, 2]. Meanwhile, as the polymer is viscoelastic, it can also improve the oil displacement efficiency [3, 4]. However, the IFT between the oil and the polymer solution is quite high; it possesses no oil solubility and emulsifiability [5]. And the recovery just can be increased by 10%, so polymer flooding is limited. The alkali-surfactant-polymer (ASP) system can reduce both the mobility ratio and the IFT, so it can effectively reduce the remaining oil saturation [6–8]. The alkali in ASP system can react with the organic acid in the oil to generate surfactant [9]. As a result, the IFT can be reduced to a larger extent due to the synergy between surfactant added and generated. What is more, the alkali can also reduce the surfactant absorption in the reservoir. However, the alkali will react with the clay mineral in the reservoir and produce the precipitate. It will result in the reservoir damage, difficulty demulsification, and the reduction of the ASP system viscosity [10]. As a new flooding method, the SP system without alkali can solve the above problems [11]. As the system is free of alkali, it can play the viscoelasticity of polymers to the maximum degree and erase the corrosion and scaling caused by alkali. While reaching an ultralow IFT, the oil displacement efficiency of SP system can be closed to the ASP system. Meanwhile, the SP system can decrease environment pollution [12].

SP flooding could enhance oil recovery because polymer can increase sweep efficiency and surfactant can improve the oil displacement efficiency. The polymer viscosity influences the sweep efficiency and the displacement efficiency depends on the IFT. The viscosity is influenced by the salinity, temperature, absorption, and shearing action [13]. And the IFT is influenced by the reservoir temperature, the composition of crude oil, and the concentration change caused by the action between the injection fluid and the rock [14]. Main controlling factor of polymer-surfactant

Table 1: Composition of injected water.

Ions	$K^+ + Na^+$	Mg^{2+}	Ca^{2+}	Cl^-	SO_4^{2-}	HCO^{3-}	CO_3^{2-}	TDS
Content mg/L	2043	36	39	1347	24	3126	135	6750

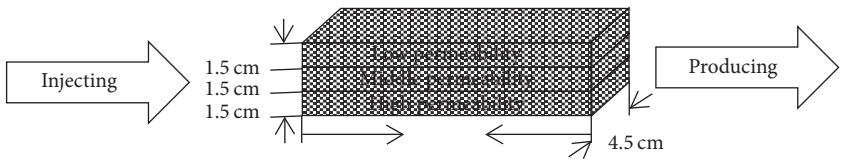


Figure 1: The two-dimensional vertical heterogeneous model.

flooding to improve recovery is different in different reservoir condition. According to the capillary number equation, if the injection can reduce the IFT to 10^{-3} mN/m, the highest recovery can be reached in homogeneous reservoirs [15–17], while, in the heterogeneous reservoir, the mobility ratio plays an important role in spreading to the middle-low permeability layer. The surfactant can activate the residual oil and form emulsion, the emulsion expands the swept volume. According to the different characteristics of the reservoir, the main controlling factors of SP flooding should be cleared out and provide the basis for the system optimization for SP flooding, especially for the Jilin Oilfield of high salinity and heavy heterogeneous.

According to the characteristics of Jilin Oilfield, a series of static experiments were carried out to study the influence of salinity and shearing action on the viscosity; other experiments are done to analyze the effect of surfactant concentration on the IFT and emulsion. According to the core flooding experiments, the influence of viscosity and IFT on the recovery is discussed. And the main controlling factors of SP flooding are analyzed. The results provide the basis on the optimization of the chemical and the injecting method.

2. Experimental Studies

2.1. Equipment. The core holder is 30 cm long, which hold the core with external pressure that is 1-2 MPa more than the inlet pressure. Other equipment includes a flowmeter, DV viscometer, high pressure middle vessel, automatic metering plunger pump, thermotank, pressure acquisition system, and constant flow pump. The pressures are recorded by the pressure acquisition system and the output liquid is collected to calculate the recovery.

2.2. Materials. The mother liquor of polymer and surfactant are prepared by the injection water; the salinity of injection water is shown in Table 1. The two-dimensional vertical heterogeneous positive rhythm artificial model with the size of 30 cm × 4.5 cm × 4.5 cm is used in the experiment, as shown in Figure 1. The model is cemented by quartz sand and epoxy resin, and the formation is divided into high, medium, and low permeability layers, with a permeability of 630 mD, 120 mD, and 30 mD, respectively, in order to simulate the main oil layer of Honggang Oilfield.

The polymer is GF-11 produced by Daqing Assistant Factory, and GF-11 is partially hydrolyzed polyacrylamide (HPAM). The average relative molecular weight of GF-11 is 2500×10^4, the degree of hydrolysis is 25%, and the solid content is 88%. The surfactant is anionic sulfonate, and the effective content is 40 wt%, 24 wt% is unsulfonated oil, 33 wt% is volatile content, and 3.0 wt% is inorganic salt. The average relative molecular weight is 645.

SP systems were prepared by the polymer whose relative molecular weight is 2500×10^4, the surfactant, and different composition water. The composition of crude oil is shown in Table 2. To get the same viscosity with reservoir oil, we used simulated oil in the experiment. The simulated oil is prepared by the degassed oil and kerosene with the proportion of 5 : 3. The viscosity of oil is 17 mPa·s in the reservoir temperature. of 45°C.

2.3. Measurement of Viscosity and IFT. The viscosity of SP system is measured by the HAAKE rotary rheometer, under the shearing rate of $7.31\,s^{-1}$. IFT is measured by TX500 at 1000 r/min after 120 min under 45°C.

2.4. Emulsification Experiment. The emulsion is prepared by the chemical and crude oil stirring at the rate of 1500 r/min for 1 minute at 45°C. The volume ratio of oil and water is 3 : 7. The micromorphology of emulsion is observed by the ZEISS SteREO Discovery.V20 microscope. In the emulsion stability experiment, putting the emulsion into the glass tube, the oil and water will separate from each other because of the density difference. The water separating proportion is defined as the ratio of the separated water volume and the original water volume after separating 2 hours and it is used to evaluate the stability of emulsion; the reciprocal of stability constant of Turbiscan Lab Expert (Formulaction Inc.) is used to evaluate the stability of emulsion at the reservoir temperature. The bigger the TSI^{-1} is, the more stable the emulsion is.

2.5. Core Flooding Experiments. At the temperature of 45°C and the constant flow of 0.1 mL/min, the experiments of water flooding, surfactant flooding, polymer flooding, and SP flooding are conducted. The experiment steps are as follows:

(1) Measure the dry weight, length, and diameter of the core; the permeability is measured by N_2.

Table 2: Composition of crude oil.

Crude oil	Hydrocarbon	Aromatic Hydrocarbons	Resin	Asphaltene
Content, wt%	59.9	22.4	4.3	8.0

(2) Vacuum the core, saturate it with the reservoir water, weigh the wet weight, and calculate the porosity. Then, saturate the core with oil and calculate the original oil saturation.

(3) Displace the oil in the core with the reservoir water; measure the output oil, water, and pressure until the water cut of the output liquid is 98%. After the water flooding, the chemical flooding is done until the water cut is 98%.

3. Results and Discussion

3.1. Influence Factor of SP System

3.1.1. Viscosity of SP System. The SP solution is prepared by the injection water of the block, and the salinity of injected water is less than that of the original formation water. Although after long-term water flooding, the salinity of formation water is nearly that of the injected water. But due to mobility control of the polymer, the injected chemical agents can sweep the area which is unsweep during water flooding. These areas are still high salinity, so the viscosity of polymer would reduce and then oil recovery decreases. Therefore it is necessary to evaluate the influence of salinity on the viscosity of polymer solution.

Figure 2 is the viscosity curve along with salinity when polymer concentration is 1500 mg/L and 2000 mg/L. It shows that viscosity decreases as salinity increases. When polymer concentration is 1500 mg/L and salinity increases from 2500 mg/L to 8400 mg/L, viscosity decreases from 60.47 mPa·s to 34.51 mPa·s and viscosity retention rate is 56.01%; when polymer concentration is 2000 mg/L and salinity increases from 2500 mg/L to 8400 mg/L, viscosity decreases from 80.49 mPa·s to 40.33 mPa·s and viscosity retention rate is 50.11%. So the higher the polymer concentration is, as salinity increases, the lower the viscosity retention rate is. According to the theory of molecular motion, the more the polymer molecular chain stretches, the more serious the intermolecular winding is, the higher the viscosity is. Double electric layer on surface of polymer molecular chain is compressed and negative charge of polymer molecular chain is blocked, which will lead to weakening of the repulsion between molecular chains, and then polymer molecular chain curls up, entanglement between molecular diminishes, and viscosity reduces. Therefore polymer concentration should be appropriately increased in order to overcome the effects of salinity on polymer solution viscosity.

In order to reduce oil-water mobility ratio effectively and enhance oil recovery, polymer solution in the formation needs high viscosity. But when polymer solution is injected, it has to pass through pump, valve, pipeline, perforation, and the pore and throat of rock and the shearing action during flooding will change the size of polymer molecule. In order to simulate the effect on the viscosity when the polymer solution is affected by the mechanical shear, inject polymer solution into one-meter long cores with the concentration of 1500 mg/L, 2000 mg/L, 2500 mg/L confected by injected water and formation water. Take a sample at the exit of the core, determine the viscosity of produced fluid at 45°C, and evaluate the shear resistance of polymers.

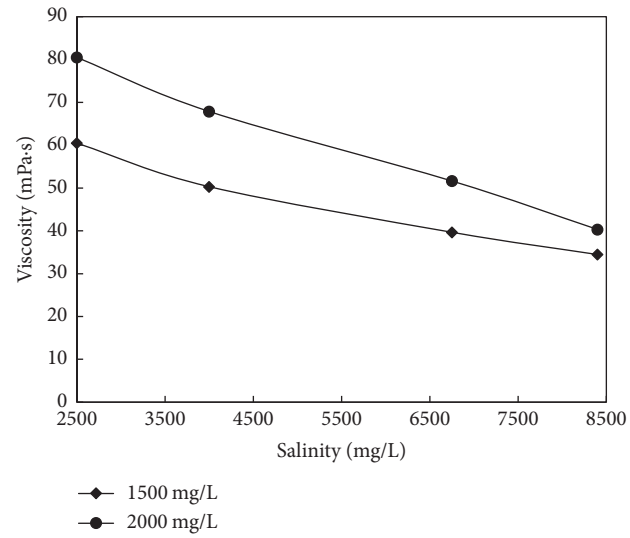


Figure 2: Viscosity of SP solution with different salinity when polymer concentrations are 1500 mg/L and 2000 mg/L.

The results are shown in Table 3. For polymer solution of 1500 mg/L, 2000 mg/L, and 2500 mg/L, the viscosity retention rate of the solution prepared with the injected water is 71.99%, 72.15%, and 74.74%, respectively, while the viscosity retention rate of the solution prepared with the formation water is, respectively, 67.33%, 68.21% and 71.32%. The results show that this polymer has strong ability to resist shear and can be used for oil displacement.

3.1.2. IFT Behavior of Crude Oil/Chemical System. As SP system has not the synergistic effect of alkali, surfactant is the key to enhance oil recovery. Excellent surfactant can keep the IFT ultralow (10^{-3} mN/m) [18]. But the activity of surfactants in the formation is affected by adsorption, retention, salinity, and dilution formation of water, so it is necessary to measure IFT between JN-1 solution and crude oil of different concentration.

The results are shown in Figure 2 that the range of surfactant concentration is 0.05–0.5 wt%, IFT of oil-surfactant-polymer solution changes with different surfactant concentrations. As shown in Figure 3 when the surfactant concentration increases from 0.05 wt% and 0.3 wt%, IFT drastically reduces from 8.4 mN/m to 4.11×10^{-3} mN/m. This is due to the fact that the surfactant molecules on the oil-water

Table 3: The viscosity of the polymer solution under different conditions.

Polymer concentration mg/L	Injected water		Formation water	
	Viscosity before shearing, mPa·s	Viscosity after shearing, mPa·s	Viscosity before shearing, mPa·s	Viscosity after shearing, mPa·s
1500	39.67	28.96	30.14	20.29
2000	51.64	37.26	42.31	28.86
2500	72.46	54.16	59.47	42.41

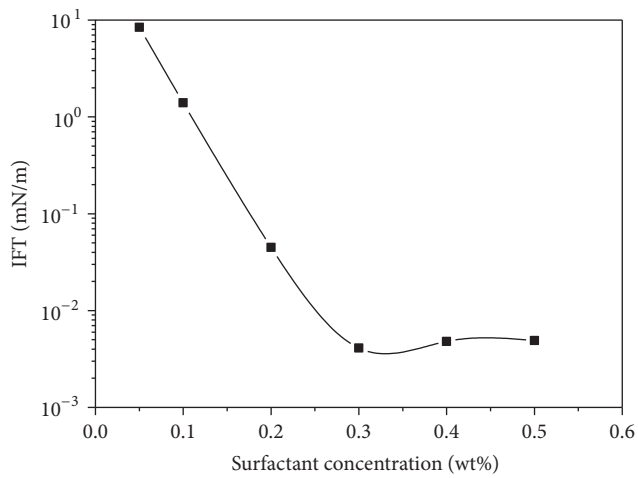


Figure 3: Minimum IFT between surfactant solution and oil with different surfactant concentrations.

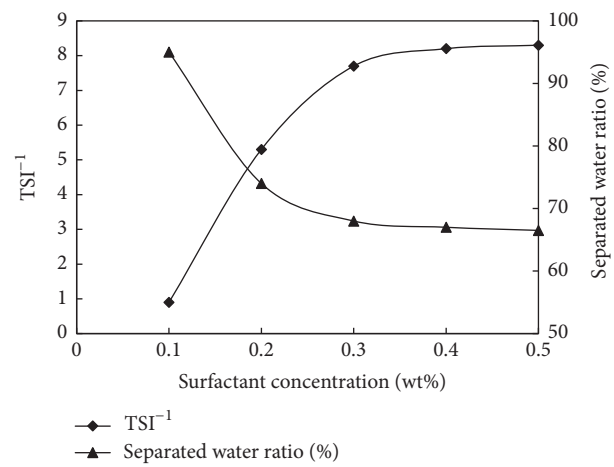


Figure 4: Relationship of TSI^{-1} and separated water ratio when surfactant concentration varies. The polymer concentration is 2000 mg/L.

interface increase as the surfactant concentration increases. When the surfactant concentration is 0.3 wt%, the adsorption of the surfactant molecules is saturated on the oil-water interface and IFT reach a minimum of about $.11 \times 10^{-3}$ mN/m, so 0.3 wt% is CMC of the surfactants and IFT slowly increase with the increase of surfactant concentration. According to the value of IFT and economic factors, choose the surfactant concentration of 0.3 wt%.

3.1.3. The Emulsification Behavior of SP Solution and Oil. Emulsification is a common phenomenon in the SP flooding and also an important mechanism for EOR [9, 14, 19]. In order to evaluate the efficiency of chemical emulsifying the oil, a series of emulsification experiments are conducted, according to the description of the experimental method in Section 2.4. In each experiment, emulsion is prepared by the oil and different chemical agents.

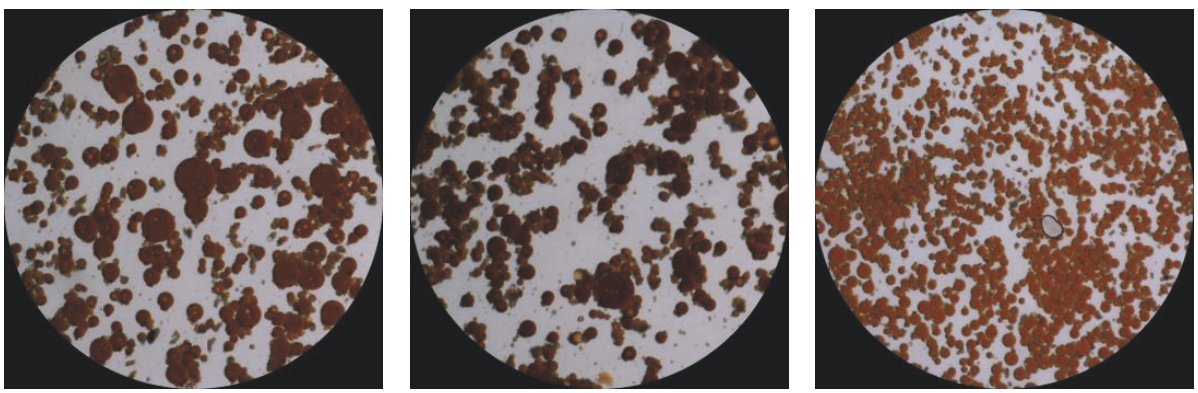
In Figure 4, the range of surfactant concentration is 0.1–0.5 wt%, and the polymer concentration is 2000 mg/L. The figure shows the relationship between the surfactant concentration and the stability of the emulsion. From the figure, it can be concluded that when the surfactant concentration increases from 0.1 wt% to 0.3 wt%, TSI^{-1} raises rapidly and the separated water ratio decreases rapidly. With the further increase of the surfactant concentration, the TSI^{-1} curves and the separated water ratio curves become relatively gentle. It indicates that the emulsion stability is stronger when the surfactant concentration increases. From Figure 2, it can be concluded that the change trend of the IFT curves and the TSI^{-1} curves is similar. That is to say, when the surfactant concentration exceeds 0.3%, the IFT and the TSI^{-1} significantly decrease and finally reach a stable value. A phenomenon appears in the forming process of emulsion: the lower the IFT is, the easier the emulsion forms.

Figure 5 is the microscopic photos of the emulsion layer which contains the three kinds of emulsion. Figure 6 shows distribution of emulsion droplet with different chemical agent. Figure 5 shows that three kinds of SP system with the water all form the O/W emulsion. The quantity of emulsion in Figure 5(c) is more than that of Figures 5(a) and 5(b) and the diameter of emulsion in Figure 5(c) is fewer and the distribution is more uniform (as shown in Figure 6), so that the emulsion in the Figure 5(c) is the most stable. It is because that the IFT in Figure 5(c) is the lowest. And it can be inferred that the low IFT is quite important in the formation of emulsion, which coincides with the above phenomenon and analysis.

3.2. Core Flooding Experiment. Under the reservoir temperature of 45°C, the heterogeneous cores of three layers are used for the SP flooding experiments. The chemical agents were prepared by the injection water. The results of polymer flooding, surfactant flooding, and SP flooding are shown in Table 4.

Table 4: Experiment data of oil displacement efficiency.

Number	Polymer concentration	Surfactant concentration	Viscosity, mPa·s	IFT mN/m	Water flooding Recovery, %	chemical flooding Recovery, %	Incremental Recovery, %
(1)	1500	0	39.67	—	39.98	49.21	9.23
(2)	0	0.3	0.67	3.53×10^{-3}	40.42	43.35	2.93
(3)	1500	0.3	40	4.12×10^{-3}	40.15	53.55	13.40
(4)	2000	0.3	51.64	6.33×10^{-3}	41.11	55.09	13.98
(5)	1500	0.2	39.47	4.51×10^{-2}	38.97	50.08	11.11
(6)	1500	0.4	38.79	4.6×10^{-3}	40.34	53.86	13.52
(7)	1500	0.3	28.97	4.92×10^{-3}	38.92	43.97	5.02



(a) (b) (c)

Figure 5: Micrographs of emulsions with different chemical agent: (a) 0.1 wt% surfactant + 2000 mg/L polymer; (b) 0.2 wt% surfactant + 2000 mg/L polymer; (c) 0.3 wt% surfactant + 2000 mg/L polymer.

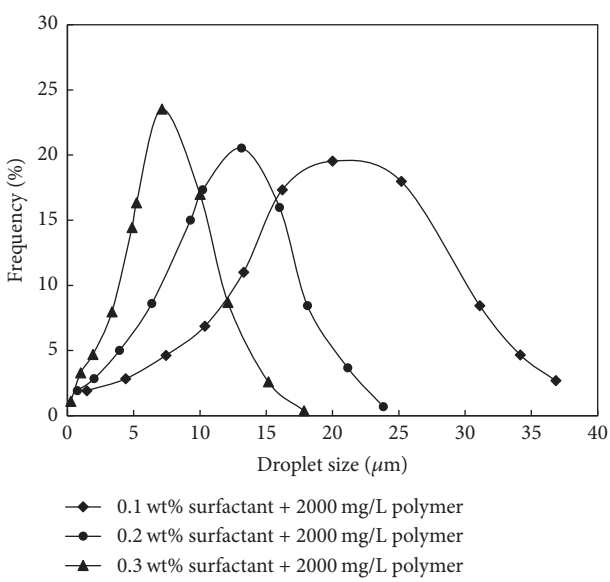


Figure 6: Distribution of emulsion droplet with different chemical agent.

3.2.1. The Influence of the Viscosity on EOR. The oil displacement experiments results of different chemical are shown in Table 3. Comparing the results of experiments (2), (3), and (4), it can be concluded that, under the conditions of a certain surfactant concentration, the recovery increases with the increase of the viscosity of polymer solution after water flooding. From the water cut and the pressure curves, it is indicated that the higher the viscosity is, the bigger the flow resistance of the injection fluid in the high permeability is and the higher the injection pressure is. And the injection fluid will turn into the middle-low permeability layers with high oil saturation and cut down the water cut. When the injection viscosity increases from 0.67 mPa·s to 40 mPa·s, the recovery improves 10.47%. And when the injection viscosity increases from 40 mPa·s to 51.64 mPa·s, the recovery improves 0.58%. This indicates that, with the increase of the injection viscosity, the recovery improves, but the degree of increment becomes smaller. Mainly because the possibility of winding between polymer molecular threads is increasing and the radius of the polymer molecular thread becomes large due to the increase of polymer concentration (see Figure 7). According to the literature [20], when the ratio of the radius of pore in the core and the radius of polymer molecular threads is greater than 5.5, the compatibility of pore and throat of the core is bad. The quantity of the polymer which can enter the middle and small pores with high residual oil saturations after water flooding is smaller. When the incremental recovery becomes obviously

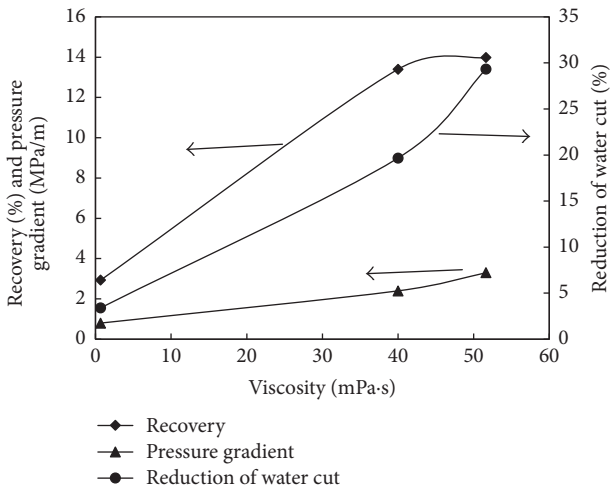


Figure 7: Relationship between enhanced recovery, maximum pressure gradient, reduction of water cut, and viscosity.

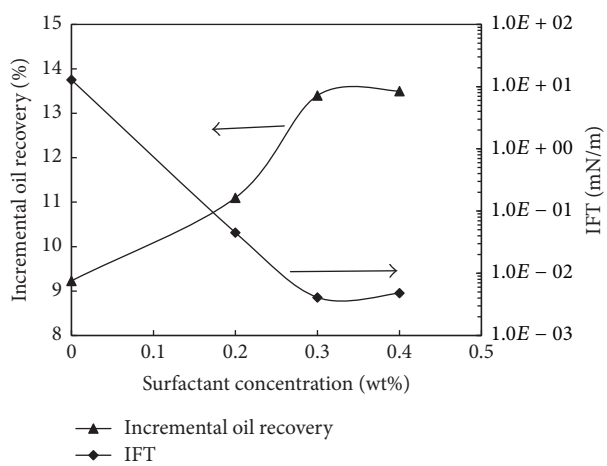


Figure 8: Relationship of IFT and incremental oil recovery when surfactant concentration varies. The polymer concentration is 1500 mg/L.

little, the injection viscosity is called the critical viscosity. At this time, the bigger viscosity, namely, the bigger polymer concentration, means less economic performance.

The SP system with polymer concentration 1500 mg/L and the surfactant concentration 0.3 wt% was injected into the core to simulate shearing during the injecting process in oilfield and then the SP system shared was used to displace oil. Comparing experiments (3) and (7), it can be concluded that the viscosity changes a lot after shearing and the recovery has an obvious decrease from 13.4% to 5.02%. This indicates that the system has a weaker mobility.

3.2.2. The Influence of the IFT on the EOR. In order to find the influence of the surfactant concentration of SP system on the EOR, 4 experiments were conducted. The range of surfactant concentration is 0–0.4 wt% and the slug size of injection chemical is 0.6 PV. It can be concluded from Figure 8 that EOR depends on the surfactant concentration at constant

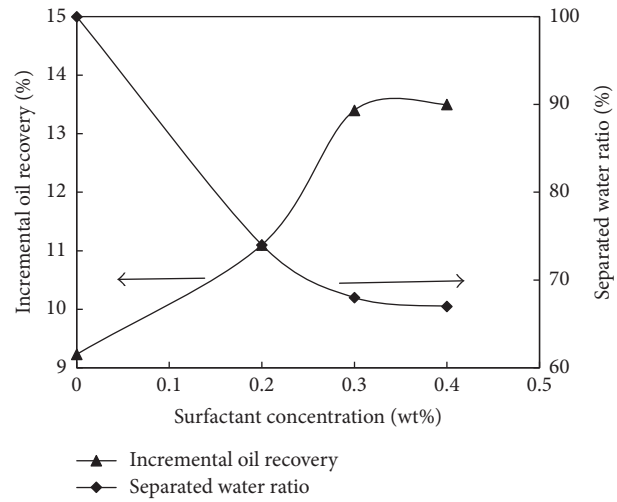


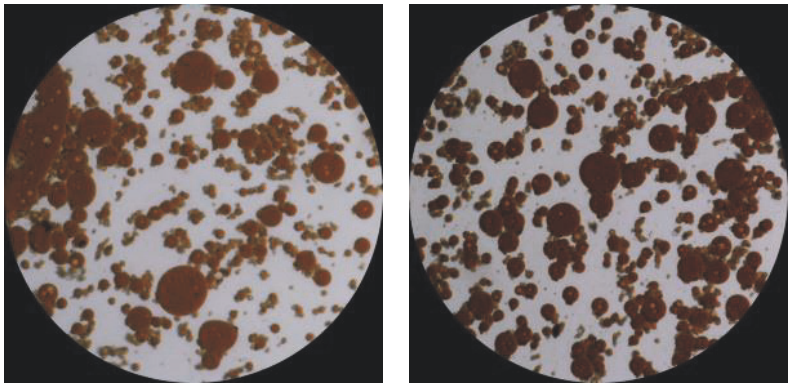
Figure 9: Relationship of separated water ratio and incremental oil recovery when surfactant concentration varies. The polymer concentration is 1500 mg/L.

polymer concentration. When the range of surfactant concentration is 0–0.3 wt%, the values of EOR increase rapidly from 9.23% to 13.40%. When the surfactant concentration has a further increase from 0.3 to 0.4 wt%, the trend of the EOR value becomes gentle. This is because the surfactant molecules are adsorbed on the oil-water contact surface. It will reduce the IFT to a rather low degree and the emulsion is easy to form. So the residual oil can be flooded more easily. Comparing the curves in Figures 8 and 9, it can be concluded that the lower the IFT is, the more stable the emulsion is and the higher the incremental oil recovery is.

The micromorphology of the output liquid in the process of chemical flooding is shown in Figure 10. Figures 10(a) and 10(b) prove that the O/W emulsion is formed in the process of injecting. This illustrates that the oil increment in the SP flooding is mainly in the form of O/W emulsion. At the same time, the results show that emulsion plays quite an important role for EOR in SP flooding.

3.2.3. Main Controlling Factor of SP Flooding to Improve Recovery. According to the traditional theory of chemical flooding, the basic methods of chemical flooding for EOR are enlarging the sweep volume and improving cleaning efficiency [21, 22]. But the two methods have different contribution to enhance oil recovery. Thus, it is of great importance to clear the main factors of SP flooding, which provides theoretical guidance for system optimization.

Comparing experiments number (1), (2), and (3), it can be concluded that different kinds of chemical have different effects on oil recovery. The SP flooding has the largest oil recovery increases, followed by the polymer flooding, and the last is surfactant flooding. Comparing with the polymer flooding and SP flooding, the surfactant flooding has better oil displacement efficiency, but as surfactant solution viscosity is low, the flow resistance does not rise and the injection pressure is not higher than the water flooding (Figure 11),



(a) (b)

Figure 10: Micrographs of produced fluids in different production periods when chemical solution was injected: (a) in the earlier production period; (b) in the later production period.

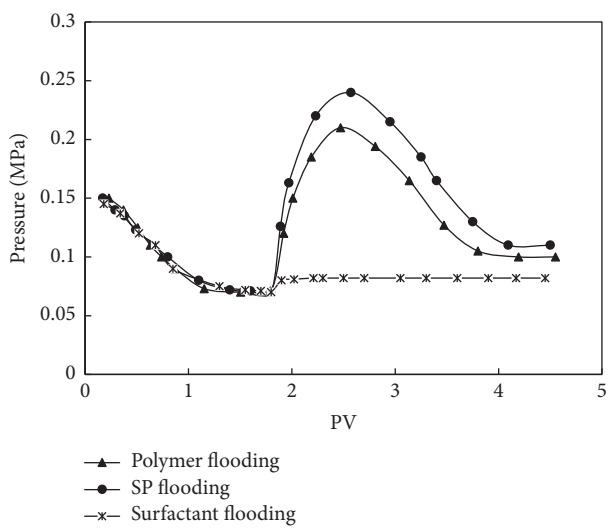


Figure 11: Relationship between inject pressure of different agent and pore volume.

which indicates that the surfactant solution is still flowing in the water channel and does not expand the swept volume. The incremental recovery is mainly from the action of washing oil. Further analysis showed that the incremental recovery of SP flooding is higher than the sum of incremental recovery of the polymer flooding and surfactant flooding, which indicates that the polymer carries surfactant into more pore volume and the surfactant will wash oil well with synergistic effect of polymer. Thus, it is quite important to expand the swept volume in the process of chemical flooding. The premise that the surfactant improves the oil displacement efficiency must be that the polymer can expand the swept volume.

SP flooding not just improves oil displacement recovery but also emulsifies oil into different sizes of drops which play the role of deep steering, improve the sweep factors of the following injection liquid, and reach the highest recovery. The oil drops are relatively large and hard to go through the throat. This is called the resistance effect (Jamin effect). The accumulation of resistance effect will result in improving the resistance factor that the liquid passes through the high permeability throat and raises the sweep factor of the following liquid. Meanwhile, under the stable effect of polymer, the emulsion can play the role of deep steering for a long time, compensating for the lack of polymer profile control ability.

4. Conclusions

(1) Salinity and shearing have a negative effect on both viscosity of polymer solution and oil recovery, so increasing the concentration of the polymer to maintain high viscosity is necessary.

(2) Different from the polymer flooding and SP flooding, the surfactant solution can only flow in the water channel and cannot improve the recovery effectively. The improving recovery of SP flooding is higher than the sum of improving recovery of the polymer and surfactant. It shows that the polymer carries surfactant into more pore volume and the oil displacing action gets full play, forming synergistic effect. It is a further explanation that the SP flooding is an effective method after the polymer flooding.

(3) The main factor of SP flooding in the heterogeneous reservoir is the mobility control action. As a result, when choosing the SP system, the viscosity should be considered first and the IFT then comes second. When the system reaches the ultralow IFT, the emulsion is easy to form and it is advantageous to the start of residual oil.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Acknowledgments

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