

## Research Article

# Effect of Emulsification on Enhanced Oil Recovery during Surfactant/Polymer Flooding in the Homogeneous and Heterogeneous Porous Media

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Surfactant polymer (SP) flooding has become an important enhanced oil recovery (EOR) technique for the high-water cut mature oilfield. Emulsification in the SP flooding process is regarded as a powerful mark for the successful application of SP flooding in the filed scale. People believe emulsification plays a positive role in EOR. This paper uses one-dimensional homogenous core flooding experiments and parallel core flooding experiments to examine the effect of emulsification on the oil recoveries in the SP flooding process. 0.3 pore volume (PV) of emulsions which are prepared using ultralow interface intension (IFT) SP solution and crude oil with stirring method was injected into core models to mimic the emulsification process in SP flooding, followed by 0.35 PV of SP flooding to flood emulsions and remaining oil. The other experiment was preformed 0.65 PV of SP flooding as a contrast. We found SP flooding can obviously enhance oil recovery factor by 25% after water flooding in both homogeneous and heterogeneous cores. Compared to SP flooding, emulsification can contribute an additional recovery factor of 3.8% in parallel core flooding experiments. But there is no difference on recoveries in homogenous core flooding experiments. It indicates that the role of emulsification during SP flooding will be more significant for oil recoveries in a heterogeneous reservoir rather than a homogeneous reservoir.

## 1. Introduction

Most of the continental sedimentary reservoirs are feathered with severe heterogeneity. More than two-thirds of the crude oil are buried in the reservoir in the form of remaining oil or residual oil after water flooding [1, 2]. Chemical flooding is widely used to enhance oil recovery in the mature oilfield, including polymer flooding, surfactant/polymer (SP) flooding, and alkali/surfactant/polymer (ASP) flooding [3]. SP flooding simultaneously enlarges the swept volume and improves the oil displacement efficiency. Compared with polymer flooding, SP flooding can further increase the recovery factor to 5%-10% [4]. With the progress of the surfactant formation, alkali-free SP flooding can maintain the similar recovery with the traditional ASP flooding, but it shows a

high economic efficiency because it can reduce the injection fluid damage to the reservoir and alleviate the scale corrosion of wellbore pipeline [5]. The advantages make SP flooding shows the great prospect in the filed-scale application.

SP solution can increase the viscosity of displacing phase and control mobility by adding water-soluble polymer and effectively mobilize trapped oil with the ultralow oil-water interfacial tension (IFT) surfactant [6, 7]. The synergy effect of polymer and surfactant can significantly improve oil recovery. Moreover, the remaining oil will be detached from the rock surface and dispersed into several small oil droplets when the SP solution flows over the adsorbed oil on the rock surface [8]. Furthermore, the large oil droplets will also be gradually dispersed into smaller oil droplets under the coaction of shear force and interfacial tension force, which result

the formation of oil-in-water (O/W) emulsions or water-in-oil (W/O) emulsions [9, 10]. Emulsification has been widely observed in a large number of laboratory and field tests. The higher oil recoveries of emulsion flooding in these cases indicate emulsification plays a positive role for further improving oil recoveries [11–14].

Unlike the thermodynamically stable microemulsions, the concentration of surfactant used in SP flooding pilot is low, which only results the formation of thermodynamically unstable emulsions [15]. Oil and water will completely separate into two phases after long-term placement. If there is dense emulsion generation during the flooding process, both the remaining oil in upswept areas and the residual oil in the swept area will be mobilized by the increment of bulk viscosity of the displacing phase and the Jamin effect [16, 17]. Moreover, the subsequent surfactant can emulsify the downstream oil and gradually move forward to continue improving oil recoveries. As early as 1973, Mcauliffe [18] found that injecting 3000 barrels of emulsified crude oil into the reservoir can produce 55000 barrels of crude oil. Since then, many studies have shown that injecting O/W emulsions into the core can produce more than 20% of original oil in place (OOIP) after water flooding. Baldygin et al. [19] found that the alternative injection of emulsions and water can produce 20% of OOIP compared to alone water flooding or emulsion flooding. Guo et al. [20] and Luan et al. [21] used surfactants with different emulsifying capacities for core flooding experiments and found that emulsification was more important than the reduction of IFT in some cases. They believed that a system with better emulsification ability can further produce 3%-5% of OOIP than the system with the same or lower IFT.

However, the heterogeneity of the reservoir is intensified after water flooding. Conventional columnar core flooding experiments hardly reflect the effect of emulsions on oil recoveries under the complicated oil and water distribution. There is no clear conclusion whether the emulsification during SP flooding with ultralow IFT surfactant can further enhance oil recoveries. To clarify these problems, this paper selects the industrially applied SP system with corresponding crude oil to generate emulsions and compare the effect of emulsification on oil displacement efficiency in the SP system on homogeneous cores and dual cores after water flooding. Our work shows that the emulsions in the ultralow IFT SP system can enhance oil recoveries in the heterogeneous dual cores rather than the homogeneous cores.

## 2. Experiment Section

**2.1. Materials. Brine:** the brine used in the experiments was injection water from Dagang Oilfield injection station. The salinity composition is shown in Table 1.

**Chemicals:** the polymer is a partially hydrolyzed polyacrylamide (HPAM) with a relative molecular weight of 30 million and a concentration of 1200 mg/L, which is provided by Dagang Oilfield. The surfactant is a petroleum sulfonate with an effective concentration of 40%, which is industrial application in Dagang SP pilots. The concentration of surfac-

tant used in the experiments is 0.5%. Figure 1 shows that the surfactant can form Winsor Type III microemulsion with crude oil at the salinity range from 0.5% to 3%. The viscosity of the SP solution is 56 mPa·s using the Brookfield DV-II<sup>+</sup> with a shear rate of  $7.34 \text{ s}^{-1}$  at 53°C. The IFT between the SP solution and crude oil is  $3 \times 10^{-3} \text{ mN/m}$ .

**Oil:** the crude oil is from a production well in Dagang Oilfield, and its viscosity is 48 mPa·s at a reservoir temperature of 53°C.

**Cores:** the cores used in the experiment are the rectangle homogeneous cores. The size of each core is  $4.5 \times 4.5 \times 30 \text{ cm}$ . The outside of the core is sealed by the epoxy resin. The permeability of homogeneous core is 1800 mD. The dual cores were used to investigate the conformance control ability of emulsions at different permeability ratio conditions. One permeability is constant 500 mD as the low-permeability zone, and the other permeability are 1250 mD, 2000 mD, and 3000 mD, which correspond to the permeability ratios of 2.5, 4, and 6, respectively, based on the real condition of SP pilots in Dagang Oilfield. In the parallel core flooding experiment, the high permeability and low permeability correspond to the permeability of 2100 mD and 700 mD. The schematic diagram of dual-core displacement experiment is shown in Figure 2.

**2.2. Experimental Scheme.** The effect of emulsion formation on oil displacement during SP flooding is compared using homogeneous cores and parallel cores. Each core model conducts two couples of experiments. Four experiments are conducted in this work. The cases with and without emulsion flooding are both firstly water flooded to the water cut of 95%. Since 0.4 PV-0.7 PV of chemical agent were used in most pilots cases [22, 23], 0.65 PV of chemical agent was used in this work. One is injected 0.65 PV of SP solution and followed by the postwater flooding to water cut of 98%. The other is injected 0.3 PV of emulsions and followed 0.35 PV of SP solution to displace the trapped oil and emulsions. The injection amount of chemical agents are kept similar with the alone conducting SP flooding. The experiment shuts off when the postwater floods the core to water cut of 98%. The injection pressure, water cut, and oil production are recorded during the whole experiment process.

The dual core with permeability ratios of 2.5, 4, and 6 were used to compare the profile control performance of emulsions. 0.4 PV of brine was firstly injected to achieve the original fractional flow rate; then, 1 PV of emulsions was injected, and the changing of fractional flow rates were recorded. The profile control performance of emulsions can be known by comparing the fractional flow changing before and after emulsion injection.

It is hard to mimic the in situ emulsification in the lab scale because the obvious emulsification needs many oil droplet accumulation, which indicates that long cores should be used to generate stable emulsions. Therefore, the prepared emulsions were used to replace in situ emulsification process in this work. Emulsions are generated using a stirrer at the rotate speed of 400 r/min. Considering the lowest water cut are always higher than 80% in the real SP flooding pilots, the oil-water ratio of emulsions was set at 1 : 4. The viscosity

TABLE 1: Brine ion composition.

Composition	K <sup>+</sup> +Na <sup>+</sup>	Mg <sup>2+</sup>	Ca <sup>2+</sup>	Cl <sup>-</sup>	SO <sub>4</sub> <sup>2-</sup>	HCO <sub>3</sub> <sup>-</sup>	Total, mg/L
Salinity, mg/L	1452	21	40	1401	12	3224	6150



FIGURE 1: Phase behavior of surfactant and crude oil. The salinity from left to right is 0, 0.25%, 0.5%, 0.75%, 1%, 2%, 3%, and 5%.

of emulsions is 65 mPa·s with a shear rate of  $7.34 \text{ s}^{-1}$  at  $53^\circ\text{C}$ , which is slightly higher than SP solution.

**2.3. Experimental Procedures.** Vacuumize the core model and saturate brine. Then, the core permeability was measured with brine, and the pore volume of each core was calculated via the difference between wet weight and dry weight of cores. The cores were placed in an oven with the reservoir temperature of  $60^\circ\text{C}$ , and crude oil were injected with a gradual increasing flow rate from 0.1 ml/min to 1 ml/min to create irreducible water saturation. After 5 days aging, each experimental scheme was performed.

The homogeneous core is firstly water flooded with a flow rate of 0.3 mL/min to the water cut of 95%, then separately conduct emulsion flooding and SP flooding with the designed injection amount. The experiments cannot be shut off until the postwater flood displace oil to the water cut of 98%. To the heterogeneous parallel cores, water flooding with a rate of 0.5 mL/min to reach the water cut of 95% and other producers are similar with those of the homogeneous core flooding experiment. During the flooding process, injection pressure, water production, and oil production were recorded. Since the formed emulsions also contained crude

oil, the recovery factor of the emulsion flooding was equal to the ratio of the difference between the cumulative oil production and the oil content in the injected emulsions to the total saturated oil of the cores. It should be noted that the oil recovery factor in this work may be lower than the real condition because not all of the injected oil can be displaced. But this error does not affect the conclusion.

In emulsion profile control experiments, 0.4 PV of brine was injected followed by 1 PV of emulsions, and the production of dual cores were separately recorded. The profile control performance of emulsions in different permeability ratios can be known by comparing the fractional flow in water flowing stage and emulsion flowing stage.

### 3. Results

**3.1. Homogeneous Core Flooding Experiment.** The images of effluent of SP flooding and combining emulsion flooding and SP flooding are shown in Figure 3. Both can observe the emulsification, but the color of the aqueous phase was darker than that of the case which emulsions were firstly injected and followed by the post-SP flooding. It means that compared to SP flooding, more oil were dispersed in the aqueous phase, which indicated that combining emulsion flooding and SP flooding can reflect the influence of emulsification on the ultimate oil recovery in the process of SP flooding.

The results of SP flooding and emulsion flooding followed by SP flooding are shown in Table 2. The recovery factors of water flooding in two experiments were similar, which indicated that they had a good repeatability. The chemical flooding of two experiments both produce 25% of OOIP, and the ultimate recovery factors are both around 64%. It indicates emulsion formation has no effect on the oil displacement efficiency in the homogeneous core because the SP solution with ultralow IFT was able to obviously increase capillary number and fully mobilized the remaining oil after water flooding. On that basis, it is hard to further improve the displacement efficiency by the generated emulsions during SP flooding.

The pressure curves of two schemes are shown in Figure 4. In the water flooding stage, the injection pressures both firstly increased with the injection volume and sharply decreased after reaching the maximum value. It means the flow resistance of water declined after water breakthrough. The injection pressure increased again when it came to chemical flooding stage. The pressure of the case of emulsion flooding combining SP flooding was significantly higher than that of SP flooding alone due to the Jamin effect and the adsorption of the emulsion droplets. But the additional pressure gradient did not contribute much oil in the homogeneous core flooding experiment.

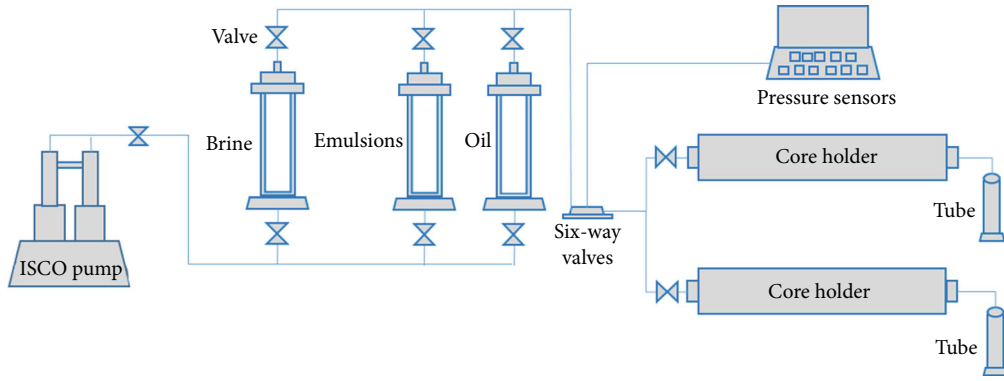


FIGURE 2: Schematic diagram of dual-core flooding experiments.

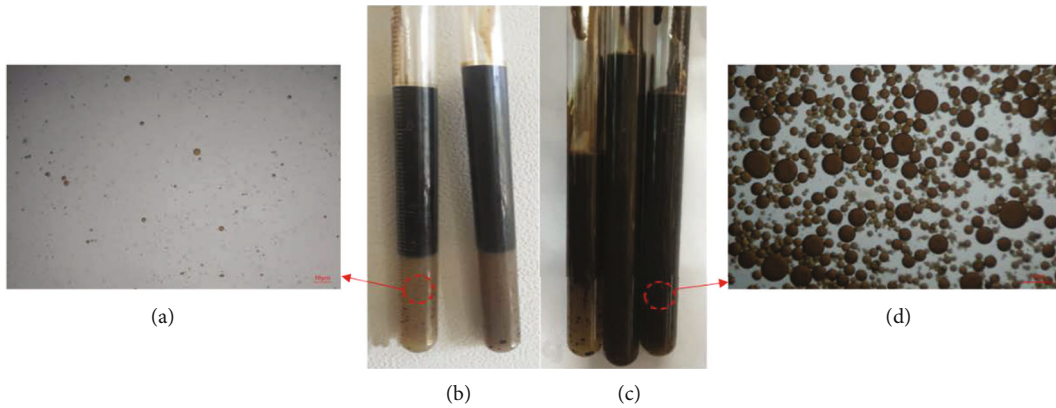


FIGURE 3: Comparison of effluent in SP flooding and emulsion flooding following SP flooding. (a) Microscopic photos of effluent of SP flooding. (b) Effluent of SP flooding in a tube. (c) Effluent of emulsion flooding in a tube. (d) Microscopic photos of effluent of emulsion flooding.

TABLE 2: Oil recoveries of different displacement stage in homogeneity core sample.

Scheme	Oil recoveries in water flood stage %	Oil recoveries in chemical flood stage, %	Incremental recoveries, %
0.65 PV of SP flooding	38.52	63.48	24.96
0.3 PV of emulsion followed by 0.35 PV of SP flooding	39.14	64.47	25.33

Figure 5 is the water cut curves of two experiments in the homogeneous core flooding experiments. The water cut of two cases were similar in the water flooding stage. They were transferred to chemical flooding when the water cut reached 95%. The water cut decreased to 40% in the case of emulsion flooding combining SP flooding, while it only decreased to 60% in the case of SP flooding alone. The degree of water cut decline and low water cut duration of the emulsion flooding were far longer than the SP flooding, but the recovery factor was similar. The reason was the oil production during the core flooding process also contained the crude oil in emulsions. Therefore, the oil recoveries of emulsion flooding were not as much as the water cut curve shown after removing the oil in the injected emulsions.

**3.2. Parallel Core Flooding Experiment.** The oil displacement result of SP flooding and emulsion flooding followed by SP

flooding in parallel cores is shown in Table 3. The recovery factors of the two schemes in the high-permeability cores were similar. While for the low-permeability cores, the case of injection emulsions followed by SP flooding can increase the recovery factor to 6.9% more than that of SP flooding alone. Compared to the SP flooding, using emulsion flooding before SP flooding can increase the intake amount of liquid in the low-permeability layer. Figure 6 shows the emulsion flooding had a more of 6.6% of fluid than SP flooding can be divided into the low-permeability core, which results in 3.8% higher recovery factors. It indicates the incremental oil recoveries are a result of the swept volume enlarged by emulsions.

The water cut and injection pressure curves of the two experimental schemes are shown in Figure 7. Compared to SP flooding, the injection pressure significantly increased when the emulsions were injected. The maximum injection pressure of emulsion flooding was 0.28 MPa, which was

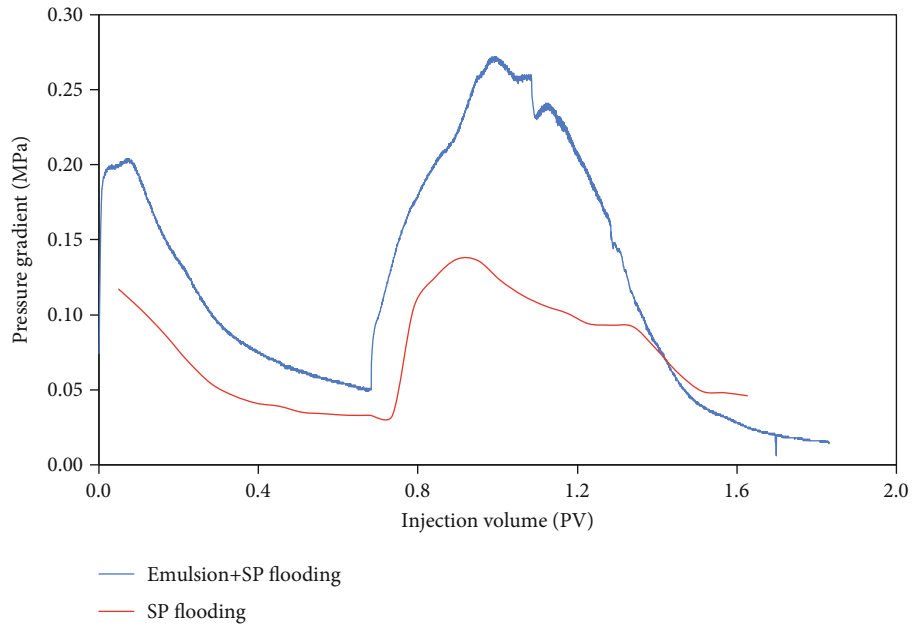


FIGURE 4: Pressure gradient curves of SP flooding and emulsion flooding following SP flooding.

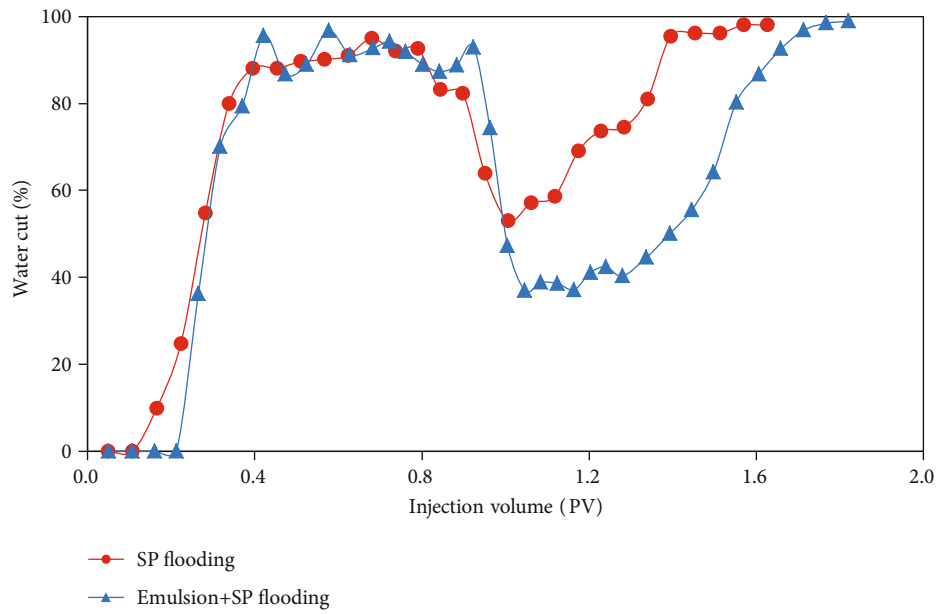


FIGURE 5: Water cut curves of SP flooding and emulsion flooding following SP flooding.

TABLE 3: Oil recoveries of different displacement stage in dual-core model.

Scheme	Oil recoveries in water flood stage %			Oil recoveries in chemical flood stage, %			Incremental recoveries, %		
	HPC*	LPC*	Total	HPC	LPC	Total	HPC	LPC	Total
0.65 PV of SP flooding	49.2	34.1	43.5	40.0	9.7	25.9	89.2	43.8	69.4
0.3 PV of emulsion followed by 0.35 PV of SP flooding	52.9	37.8	45.4	42.0	16.6	29.7	95.9	54.4	75.1

HPC: high-permeability core; LPC: low-permeability core.

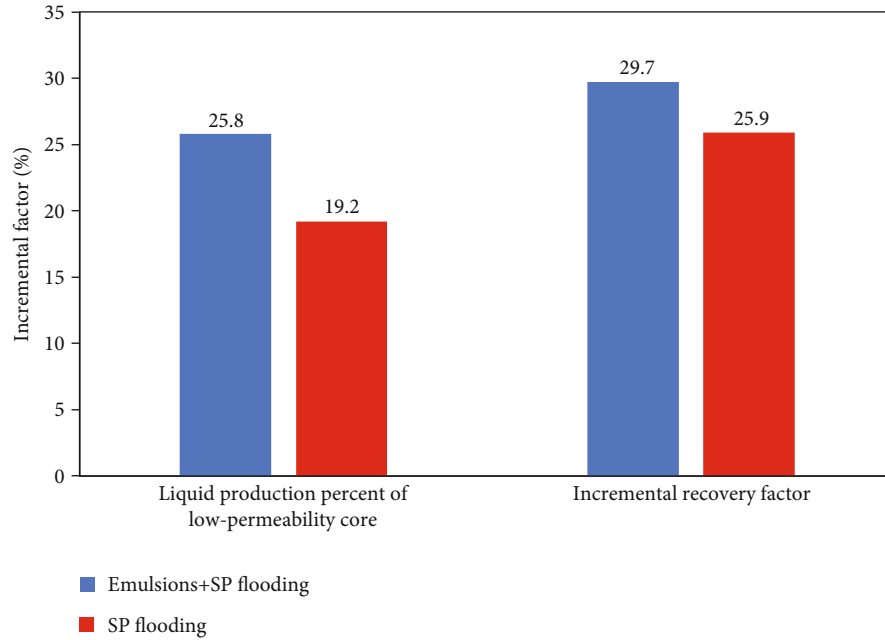


FIGURE 6: Liquid production percent of low-permeability core and incremental recovery factors of two experimental schemes.

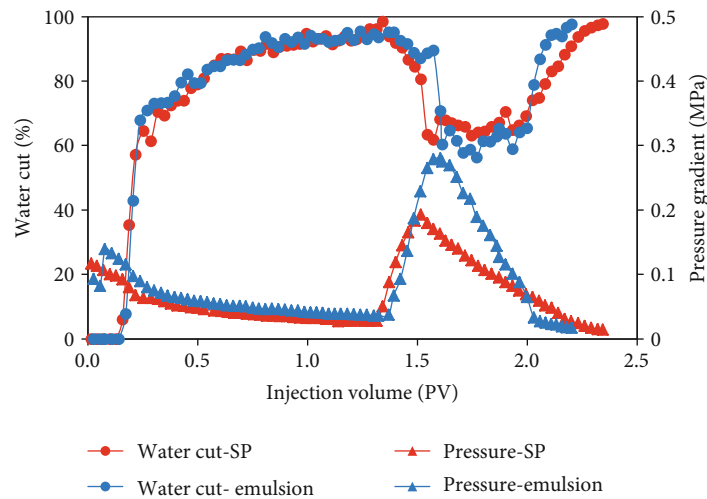


FIGURE 7: Water cut vs. injection amount and pressure gradient vs. injection amount in two experimental schemes.

significantly higher than 0.18 MPa of surfactant flooding. The injection pressure in the chemical flooding stage of two cases both rises to the maximum and then rapidly dropped. The reason is the ultralow IFT SP solution surfactant makes the capillary force between the water phase and the crude oil very small. It was difficult to rely on the flow resistance between two phases to maintain a high injection pressure when the oil bank was pushed out [24].

The fractional flow vs. injection amount curves were shown in Figure 8. The fractional flow of the high- and low-permeability layer presented a pseudo-steady tendency at the end of water flooding stage. As the SP solution injection, the viscous SP solution was first entered into the high-permeability layer, which resulted the flow resistance of high-permeability layer increasing. It will lead the liquid

inflow of the high-permeability layer decline, and the liquid inflow of the low-permeability layer increases. Simultaneously, the resistance of the low-permeability layer obviously increases as more liquid entered. But the increase of flow resistance was much greater than that in the high-permeability layer under the same injection amount. Therefore, the fractional flow of the low-permeability layer decreased, and that of the high-permeability layer raised, which presented a U-shape. If a higher-viscosity emulsion is injected after water flooding, the fractional flow of the low-permeability layer will increase much more than SP flooding. But it will sharply drop when the low-viscosity SP solution injected, as shown in Figure 8. These factors make the liquid production percent of low-permeability layer in the case of emulsion flooding followed by SP flooding was

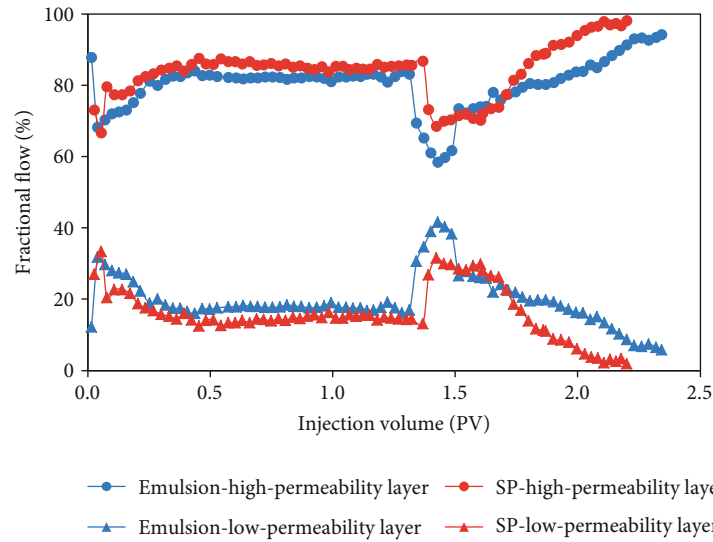


FIGURE 8: Fractional flow vs. injection amount in two experimental schemes.

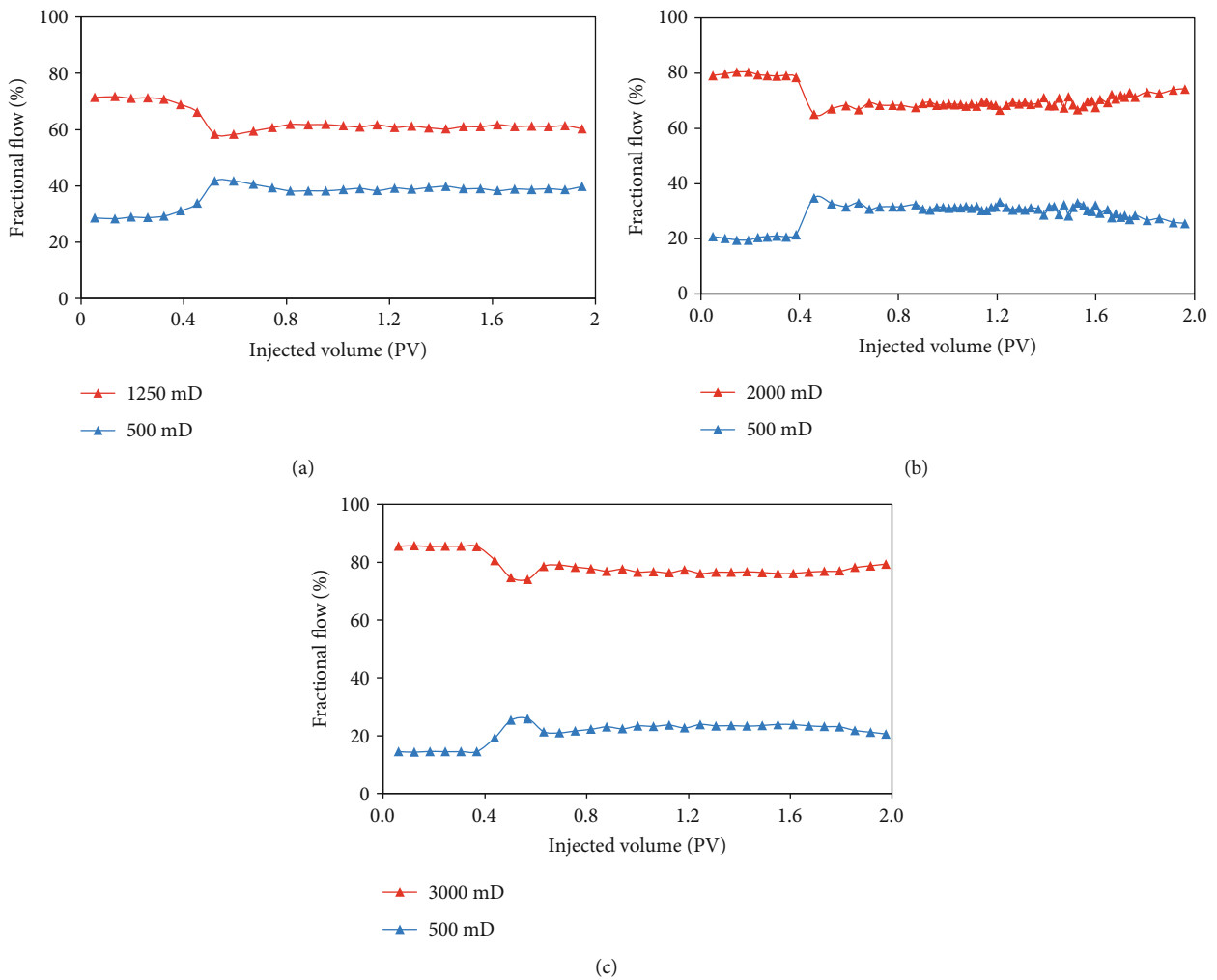


FIGURE 9: Fractional flow of different permeability ratio cores during brine injection and emulsions injection. (a) Permeability ratio is 2.5; (b) permeability ratio is 4; (c) permeability ratio is 6.

still higher than that in the SP flooding alone, as shown in Figure 6.

**3.3. Emulsions Profile Control Experiment.** The emulsions flowing in dual cores with permeability ratios of 2.5, 4, and 6 are used to investigate the emulsion profile control ability. Figure 9 is the fractional flow of dual core before and after emulsion injection. The fractional flow of brine equals to the permeability ratio of two cores. The fractional flow of high-permeability core decreases when emulsions are injected, which indicates the emulsions can control the profile by increasing the flow resistance. However, it slightly goes down with emulsion injection because the emulsions are inevitable entering into the low-permeability core and makes the flow resistance in low-permeability core increase. The fractional flow difference of dual cores becomes large with the permeability ratios increasing.

The difference between the average fractional flow of water flowing and that of emulsion pseudo-steady flowing stage can reflect the emulsion profile control ability. In the case of permeability ratio of 2.5 and 4, the value is around 8. But when the permeability ratio increases to 6, the value is 6.1. Therefore, it is hard for emulsions to control profile when the permeability ratio is larger than 6.

#### 4. Conclusion

One-dimensional homogeneous core flooding experiments and parallel core flooding experiments were separately conducted to compare the roles of emulsification on oil recoveries during SP flooding. It was found that SP flooding with ultralow IFT can further increase recovery factor to 25% after water flooding in both homogeneous cores and parallel cores. Emulsions will enlarge swept volume via adsorption and Jamin effect, which make a higher recovery factor of 3.8% in the parallel core flooding experiments. However, compared to directly conduct SP flooding after water flooding, there is no obviously difference on oil recoveries in the experiment of first emulsion flooding and then followed by SP flooding in the homogeneous cores. However, the emulsion profile control ability decreases when the permeability ratio is larger than 6. It can be concluded that emulsification may play an important role in the heterogeneous reservoir within a certain range.

#### Data Availability

Data are available on request.

#### Conflicts of Interest

The authors declare that they have no conflicts of interest.

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