Experimental Investigation of Polymer Enhanced Oil Recovery under Different Injection Modes

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ABSTRACT: To solve the problem of poor adaptability of the single slug polymer injection mode which lead to profile inversion, non-effective circulation of polymer solution in the high permeability zone during the development of conventional heavy oil, new technology of alternative injection, and three-stage slug injection for further improving polymer flooding performance were developed. Parallel sandpack flooding experiment was conducted to study the oil displacement efficiency of different injection modes, and reasonable injection mode and optimal slug combination of polymer flooding are selected. The results show that under the same polymer dosage, the high and low mass concentration polymer slug alternative injection is better than the three-stage slug and single slug polymer flooding, and with the increase of the alternating rounds, the polymer flooding performance increased first and then decreased. Compared with the single slug injection, the alternative injection increased the recovery factor by 4%. When the three-stage slug is injected, the concentration of the front and post slug has a significant effect on the oil displacement process. The optimal oil displacement formulations are as follows: main slug 5000 mg/L × 0.125 PV, secondary slug 3000 mg/L × 0.208 PV, alternating two rounds.

1. INTRODUCTION

Polymer flooding has been recognized as an effective technology to enhance oil recovery. The basic idea of polymer flooding is to increase the injected water viscosity, improve mobility ratio thus give rise to a more confrontable oil—water front during water flow in heterogeneous formation.1,2 At present, the application object of polymer flooding is expanding from high permeability reservoir to low and medium permeability reservoir,3−5 from conventional condition formation to high temperature and high salinity reservoir,6 and from sandstone reservoir to carbonate reservoir.7 In recent years, because of the shallow thin layer and many layers of the heavy oil reservoir, heat injection gain limited displacement effect; people have discussed the applicability of polymer flooding in a complex heavy oil reservoir.8 Single slug injection has long been performed in high heterogeneous reservoirs with problems of profile inversion and breakthrough of displacement fluid in the high permeability layer while much oil not produced in the low permeability layer. At present, problems of injection difficulty in some wells and over much polymer dosage of polymer flooding exist in some polymer flooding blocks. Therefore, it is of paramount importance to evaluate and select the most effective polymer injection method to gain better development effect.

Profile inversion9,10 and viscous fingering instability11−17 are two main problems of polymer injection. Mungan18 first proposed the multistage polymer injection method, by using a slug of varying rather than constant polymer concentration, the slug stability and oil recovery were increased. Then, Uzoigwe et al.19 investigated the performance of programmed polymer slug through numerous numerical simulation. A large number of scholars have optimized the injection parameters of polymer flooding. A conceptual model of typical well groups has been established and optimized the optimal viscosity ratio of polymer to crude oil through numerical simulation.20,21 The effect of polymer solution rheology, injection rate, and polymer concentration on oil displacement was been studied through sand-filled pipe model displacement experiment.16 In terms of the influence of different injection methods on the displacement effect, a series of researches have been carried out by some scholars. Ding et al.22 optimized the parameters of polymer flooding of ordinary heavy oil through numerical simulation. The research results show that under the same slug amount, the enhanced oil recovery of polymer flooding is not...
sensitive to the change of structure and concentration, but the effect of high concentration combination is relatively good. Lu et al.23 and Deng et al.24 conducted polymer flooding experiments based on the heterogeneous sand filling model, and studied the influence of the slug size and combination mode on oil recovery. The results show that the single slug polymer flooding effect is better than the three-stage slug. Many investigators25–28 compared the polymer flooding effect of the single slug and three-stage slug through physical simulation of the two-dimensional longitudinal heterogeneous oil displacement model. They concluded that the displacement effect of the polymer three-stage graded polymer slug injection scheme is better than that of single slug flooding under the same polymer dosage and injection rate. Zhang et al.29 studied the oil displacement effect of two slug combination polymer flooding and single slug flooding through four parallel core flooding experiments, the result shown that under the condition of the same polymer slug size, with the increase of polymer concentration and dosage, the recovery rate of chemical flooding increased but the increase range became slower. When the amount of polymer usage is the same, the change of slug size and polymer concentration has no significant effect on oil recovery. Cao et al.30 and Han et al.31 propose novel polymer injection modes to improve the displacement effect of heterogeneous reservoir by alternative injection of polymer slugs with different concentrations, their experimental results show that alternative injection increases the liquid absorption of the low permeability core, improves the recovery of alternative polymer injection than the conventional polymer injection method, and greatly reduces the polymer consumption. According to Zhou,32 the multistage slug displacement method can rapidly improve the energy accumulation intensity, when the energy accumulation intensity exceeds a certain value, the water cut decreases rapidly, and the recovery efficiency increases greatly. Wu et al.33 found that the pressure gradient of alternative slug injection is higher than that of single slug injection in a wide range by comparing the pressure gradient of alternative slug injection with that of single slug injection in laboratory physical simulation experiment. That is to say, the residual oil stress and deformation force generated by a pressure gradient during alternative injection make it larger than that of general injection in a long time, meanwhile, they concluded that the optimal alternating rounds is four.

In this paper, we made a systematic comparison and analysis of a dynamic polymer flooding process and displacement efficiency under different injection modes. Through parallel core flooding experiment, the influence of single slug, alternate injection and three-stage slug injection modes, and slug combination on the polymer displacement effect is investigated.

2. EXPERIMENTAL SETUP AND PROCEDURE

2.1. Experimental Materials and Conditions. The oil used in this experiment was made up of simulated oil, and the mass ratio of ground degassed crude oil and kerosene is 100:16 with viscosity of 65.1 mPa·s (72 °C). Experimental water is prepared according to ion composition of formation water with ion composition shown in Table 1 and total salinity of 10,289 mg/L. A physical model with parallel artificial cores is manufactured based on heterogeneity and physical parameter of polymer flooding reservoirs in Shengli Oilfield with basic data shown in Table 2. The polymer molecular weight is 16 to 19 million, hydrolysis degree is 25%. The viscosity of different concentrations of HPAM was measured at 72 °C, and the polymer solution viscosity versus shear rate is shown in Figure 1.

Table 1. Mass Concentration of Ions in Simulated Water

| Ion composition | Concentration (mg/L) |
|-----------------|---------------------|
| HCO₃⁻           | 430                 |
| SO₄²⁻           | 25                  |
| Cl⁻             | 5677                |
| Mg²⁺            | 44                  |
| Ca²⁺            | 272                 |
| Na⁺K⁺           | 3841                |

2.2. Experimental Device. Incubator, intermediate vessel, ISCO pump, vacuum pump, core holder, magnetic stirrer, pressure sensor, Brookfield viscometer, and electronic balance are the devices used in the experiment.

2.3. Experimental Procedure. The experimental procedures are as follows: (1) Make cores, measure dry weight and gas permeability, and select cores with different permeability levels; (2) core vacuumization with simulate formation water, determine porosity by weighing, and measure effective water permeability; (3) place the cores saturated with water in the core holder and put them in the incubator, and aging for more than 12 h at 72 °C; (4) the oil flooding saturation simulation was conducted at the flow rate from small to large, and the oil saturation was determined until no water was discharged from the core at each flow rate, then the core was aged in the incubator for more than 12 h; (5) water flooding: water was injected at 0.2 mL/min until the water cut of outlet reaches 98%, and the recovery factor of water flooding was calculated; (6) polymer solution preparation: polymer solution with a mass concentration of 5000 mg/L is prepared first which is allowed to stand at room temperature for 24 h, then diluted to the solution of the required mass concentration for the experiment, and after shearing pretreatment, it is placed in the constant temperature box for 2 h; and (7) polymer flooding: polymer flooding is carried out according to the experimental scheme until the water content is 98%, and the recovery rate of polymer flooding is calculated.

2.4. Experimental Scheme Design. Three experiment scenarios are designed, which are single slug injection, alternative injection, and three-stage slug injection. Table 3 shows injection patterns, all schemes with a fixed polymer dosage. One round of alternative injection with the high concentration slug and low concentration slug is called an alternative cycle.

3. EXPERIMENTAL RESULTS AND DISCUSSION

3.1. Effect of Polymer Concentration on Oil Displacement in Single Slug Displacement. The effect of mass concentration on polymer flooding is evaluated by incremental oil recovery, which is shown in Table 4, and it can be seen that the larger the mass concentration of polymer injection is the larger the incremental oil recovery. As the mass concentration of polymer solution increases, the polymer viscosity increases, resulting in the increase of flow resistance; the mobility ratio was further improved, which lead to a better sweep efficiency of low permeability layer. With the increase of injected polymer concentration, the oil recovery of low permeability layer increases, and when the polymer injection concentration was 2000 mg/L and 3000 mg/L, the difference between incremental oil recoveries of two cases is 0.1%. However, when the polymer concentration increased to 5000 mg/L, the incremental oil recovery of high and low permeability layer were 18.6 and 14%, respectively, and the total incremental oil recovery were 6% higher than the two low concentration
Table 2. Basic Parameters of the Cores

| case | core number | core diameter (cm) | length (cm) | gas permeability (10⁻¹⁴ μm²) | porosity | pore volume (mL) | permeability contrast |
|------|-------------|--------------------|-------------|------------------------------|----------|-----------------|----------------------|
| 1    | G1-1        | 2.391              | 6.798       | 1036                         | 0.280    | 8.56            | 2.0                  |
| 2    | G1-2        | 2.52               | 7.016       | 1105                         | 0.283    | 9.90            | 2.0                  |
| 3    | G1-3        | 2.524              | 6.972       | 1080.0                       | 0.285    | 9.94            | 2.0                  |
| 4    | G1-4        | 2.44               | 7.15        | 2123                         | 0.330    | 11.05           | 2.0                  |
| 5    | G1-5        | 2.540              | 7.850       | 1068.0                       | 0.299    | 10.33           | 2.1                  |
| 6    | G1-6        | 2.451              | 7.800       | 2180.0                       | 0.326    | 11.99           | 2.0                  |
| 7    | G1-7        | 2.38               | 7.78        | 2183.78                      | 0.307    | 13.31           | 2.1                  |
| 8    | G1-8        | 2.42               | 7.850       | 2198.0                       | 0.324    | 11.50           | 2.0                  |
| 9    | G1-9        | 2.44               | 7.02        | 2155.0                       | 0.310    | 10.11           | 2.0                  |
|      |             |                    |             |                              | 0.300    | 9.75            | 2.0                  |

Table 3. Polymer Injection Modes Design

| injection modes         | case | polymer slug concentration (mg/L) × slug size (PV) | dosage (mg/L PV) |
|-------------------------|------|----------------------------------------------------|------------------|
| single slug injection   | 1    | 2000 mg/L × 1.25PV                                 | 2500             |
|                         | 2    | 3000 mg/L × 0.83PV                                 |                  |
|                         | 3    | 5000 mg/L × 0.5PV                                  |                  |
| alternative injection   | 4    | first slug:5000 mg/L × 0.25PV alternating one cycle |                  |
|                         | 5    | first slug:5000 mg/L × 0.25PV alternating two cycles|                  |
|                         | 6    | first slug:5000 mg/L × 0.25PV alternating three cycles|                  |
| three-stage slug injection | 7 | front slug:5000 mg/L × 0.25PV second slug:5000 mg/L × 0.25PV third slug:1000 mg/L × 0.5PV |                  |
|                         | 8    | front slug:5000 mg/L × 0.25PV second slug:5000 mg/L × 0.25PV third slug:2000 mg/L × 0.25PV |                  |
|                         | 9    | front slug:5000 mg/L × 0.25PV second slug:5000 mg/L × 0.25PV third slug:2000 mg/L × 0.25PV |                  |

Figure 1. Polymer solution viscosity versus shear rate.

polymer flooding scenario, indicating that high concentration polymer flooding can further improve the mobility ratio, making the more injected water enter into the low permeability layer, thus displacing more oil from the low permeability layer, the oil displacement efficiency was improved.

Figures 2 and 3 show the recovery factor and water cut curve of single slug polymer flooding under different polymer concentrations, it can be seen that water cut decrease when different concentrations of polymer were injected; however, the water cut decline ranges were different. Water cut of high polymer concentration (5000 mg/L) scenario was reduced to almost 60%, which was low compare to other two scenario, mainly because the increase of polymer solution mass concentration will cause its viscosity to increase simultaneously, thus the profile conformance was further improved. The final recovery factor of polymer flooding was 42.9% with concentration of 5000 mg/L which were 4.1 and 4.6% higher than low (2000 mg/L) and medium (3000 mg/L) concentrations polymer injection scenario.

To make a mechanism analysis of the experimental result, we drawn the mechanism map as shown in Figure 4. For water flooding (WF) process, the injected water break through quickly in the high permeability layer which result in low displacement efficiency. For the low concentration polymer flooding (LCPF), injected polymer first enter into the high permeability layer, which increases the flow resistance of subsequent injected water, then water divided into low permeability layer to displace more oil, as the post water flooding continues, the injected water break through the polymer slug that distributed in the high permeability layer, and the phenomenon was depicted as profile inversion.5,6 As for the high concentration polymer flooding (HCPF), injected polymer that distributed in the high permeability layer give rise to a higher and stable flow resistance than LCPF, more injected water was divided into the low permeability layer, which lead to a better polymer flooding performance.

3.2. Effect of Slug Alternation Cycles on Oil Displacement. It can be seen from the enhanced oil recovery results for alternative polymer injection case (Table 5) that oil displacement efficiency of case 5 is better than that of case 4 and case 6, indicating that the number of alternative cycles has an impact on the oil displacement effect. A change in the number of alternative rounds from one to three, the
corresponding size of main and auxiliary slugs decrease from 0.42 to 0.14 PV. Under the same amount of polymer, the recovery factor of alternating two cycle (case 5) is the highest (20.5%), which is 4% higher than that of alternating one cycle (16.5%) and 6.4% higher than that of alternating three cycle (14.1%). When the polymer alternating slug size is large, it is making the alternative slug injection time too long to effectively control the mobility. Also, a small polymer alternative slug was easy to be damaged, which lead to viscosity lose.

Therefore, the optimal alternative cycle is two under the small permeability contrast formation condition.

Figures 5 and 6 show the recovery factor and water cut curve under alternative polymer injection. Due to the large oil—water viscosity ratio, it can be seen that the water cut increases rapidly during the water flooding period. As the water cut reaches 98%, the water cut starts to decrease in varying degrees, indicating that polymer flooding played a role in profile control and water plugging, the displacement efficiency of low-permeability core was enhanced. It can be seen that the shape of water cut curve of alternating one cycle and alternating three cycle presents V-shape. However, the water cut curve of alternating two cycle (case 5) presents W-shape, and the falling section maintains for the longest time, which lead to a higher incremental recovery factor.

The schematic map of the alternative polymer flooding process is shown in Figure 7, and it can be seen from Figure 4 that alternative polymer injection for one cycle (API-1) would lead to water breaking through during the post water flooding period due to profile inversion. However, for the injection mode that is the alternative polymer injection for two cycle (API-2) as shown in the figure, as the water begins to penetrate into the high concentration slug, a second high concentration slug to a part of second cycle was injected, thus water break through from the high concentration polymer slug was inhibited, more water flow divided into the low permeability layer, which give rise to a confrontable flooding profile of heterogeneous formation. For the alternative polymer injection three cycle (API-3) process, water can easily break through the polymer slug due to its small size compared with API-1 and API-2, which lead to a poor displacement efficiency.

### 3.3. Influence of Concentration of Pre-Flush Slug and Protection Slug on Oil Displacement Effect

To investigate the effect of pre-flush and protection slug concentration on oil displacement effect, the concentration of main slug and slug size remain unchanged, and the concentration of the front slug and the protective slug are changed.

The experimental results of oil recovery are shown in Table 6. It can be seen that when the concentration of the main slug and the polymer dosage keep the same, the polymer flooding recovery factor (17.7%) of the pre-flush slug with high concentration of 5000 mg/L is 5.5% higher than that of 4000 mg/L.

| case number | water flooding recovery factor/% | polymer flooding recovery factor/% | incremental oil recovery/% |
|-------------|----------------------------------|----------------------------------|--------------------------|
|             | HP | LP | total | HP | LP | total | HP | LP | total |
| 1           | 35.2 | 19.6 | 28.4 | 47.8 | 26.8 | 38.8 | 12.6 | 7.2 | 10.4 |
| 2           | 36.8 | 17.1 | 27.9 | 48.0 | 26.6 | 38.4 | 11.2 | 9.5 | 10.5 |
| 3           | 34.9 | 17.2 | 26.4 | 53.5 | 31.2 | 42.9 | 18.6 | 14 | 16.5 |

aHP is the high permeability layer; LP is the low permeability layer.

Table 4. Enhanced Oil Recovery Results for Single Slug Polymer Injection with Different Concentrations

![Figure 2](https://dx.doi.org/10.1021/acsomega.0c04138)

Figure 2. Recovery factor curves under single slug polymer flooding with different concentrations.

![Figure 3](https://dx.doi.org/10.1021/acsomega.0c04138)

Figure 3. Water cut curves under single slug polymer flooding with different concentrations.

![Figure 4](https://dx.doi.org/10.1021/acsomega.0c04138)

Figure 4. Schematic map of water and single slug polymer flooding process.
mg/L in case 9, which indicates that polymer flooding with the high concentration pre-flush slug lead to high displacement efficiency than the low concentration case because of the high concentration polymer solution preferentially entering into the high permeability layer. After that, it plays a more obvious role in plugging, making the subsequent polymer main slug easier to enter into the small pores of the low permeability layer. It can also be seen from the water cut curve (Figure 9 that the water cut decline range of scenario 7 and scenario 8 after polymer injection is higher than that of case 9 with the pre-flush slug concentration of 4000 mg/L. At the same time, comparing the recovery factor of case 7 and case 8, it can be seen that when the pre-flush slug and the main slug are fixed, the post protection slug has a significant impact on the oil displacement effect.31 With the decrease of concentration of the post protection slug, the recovery factor of polymer flooding gradually decreases. The final recovery of 2000 mg/L protection slug concentration is 2.2% higher than that of 1000 mg/L in case 7 (15.5%). When the plugging effect of the pre-flush slug and main slug is better, the high concentration protection slug is easier to enter into the low permeable layer than the low concentration slug, and when the concentration of protection slug is low, the follow-up water is easy to break through the protection slug, which damaged the polymer displacement efficiency, which has shown a same displacement pattern as in the AIP-3 process.32 As shown in Figure 9, the water cut shows a second decrease at about 2PV due to the protection effect of high concentration post slug in case 8, which can be illustrated by the AIP-2 process.

Table 5. Enhanced Oil Recovery Results for Alternative Polymer Injection Case

| case number | water flooding recovery factor/% | polymer flooding recovery factor/% | incremental oil recovery/% |
|-------------|---------------------------------|----------------------------------|--------------------------|
|             | HP | LP | total | HP | LP | total | HP | LP | total |
| 4           | 37.2 | 16.5 | 53.5 | 35.2 | 14.5 | 49.7 |
| 5           | 33.7 | 16.8 | 50.5 | 36.8 | 21.2 | 58 |
| 6           | 34.5 | 16.2 | 50.7 | 38.1 | 25.7 | 63.2 |

Figure 5. Recovery factor curve under the alternative polymer flooding method.

Figure 6. Water cut curve under the alternative polymer flooding method.
Figure 8 shows the recovery factor curve of slug combination polymer flooding. The turning point when the recovery factor curve starts to increase of case 8 was earlier than case 7 and case 9. With the high concentration pre-flush and main polymer slug entering the high permeability layer, the seepage resistance of high permeability layer is increased, and the protection slug begins to enter into the low permeability layer, and with the increase of protection slug concentration, the recovery curve of the low permeability layer shows a similar increasing trend as to the high permeability layer.

3.4. Comparison of Recovery Factor under Different Injection Modes. From the above analysis, it can be seen that case 3, case 5, and case 8 were the optimal scheme for oil displacement effect under the three injection modes, and the comparison of the recovery factor of three cases is shown in Figure 10, the total incremental oil recovery factor from high to low is alternative polymer injection (case 5), three stage polymer slug injection (case 8), and single slug continuous polymer injection (case 3). However, for the low permeability layer, the alternative polymer injection method can improve the liquid absorption of the low permeability layer, thus greatly improving the recovery factor. Moreover, the polymer alternative injection method can increase the recovery factor of the low and high permeability layer by 20 and 21.2%, respectively, and the total incremental recovery factor by 20.5%.

4. CONCLUSIONS
For the heterogeneous formation with small permeability contrast, under the same amount of polymer, the displacement effect of the high and low mass concentration polymer alternative slug is better than that of single slug and three stage slug injection, incremental oil recovery can be 4% compared to single slug, 2.8% to three stage slug, and there was a reasonable alternating cycle, i.e., alternating two rounds to obtain the maximum recovery increment.

For three-stage slug polymer flooding, the concentration of pre-flush slug and post protection slug has an impact on displacement efficiency, and reasonable pre-flush slug concentration can effectively plug the high permeability layer. Reasonable protection slug concentration can not only protect the main slug from breaking through by follow-up water but also effectively improving the mobility ratio.

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Notes
The authors declare no competing financial interest.

ACKNOWLEDGMENTS
The research was funded by the National Natural Science Foundation of China (51774308), and the National Science and Technology Major Project (grant nos. 2016ZX05058-001-007).

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