Experimental evaluation of ASP flooding to improve oil recovery in heterogeneous reservoirs by layered injection approach

Bin Huang1,2 | Xinyu Hu1 | Cheng Fu1,2 | Li Wang3

1Key Laboratory of Enhanced Oil Recovery (Northeast Petroleum University), Ministry of Education, College of Petroleum Engineering, Northeast Petroleum University, Daqing, China
2Post-Doctoral Scientific Research Station, Daqing Oilfield Company, Daqing, China
3Daqing Oilfield Oil Production Engineering Research Institute, Daqing, China

Correspondence
Bin Huang and Cheng Fu, Key Laboratory of Enhanced Oil Recovery (Northeast Petroleum University), Ministry of Education, College of Petroleum Engineering, Northeast Petroleum University, Daqing 163318, China. Emails: huang_bin_111@163.com (BH); cheng_fu111@163.com (CF)

Funding information
National Natural Science Foundation of China (51974088), National Natural Science Foundation of China (51804077), and Excellent Scientific Research Talent Cultivation Fund of Northeast Petroleum (SJQHB201803).

Abstract
To improve the oil displacement effect of ASP (alkali/surfactant/polymer) solution in heterogeneous oil reservoirs, layered injection technology is proposed for the first time for Daqing Oilfield. The technology uses partial pressure tools to control the injection amount of ASP solution in high-permeability oil layers and uses a partial quality tool in low-permeability oil layers. To study the experimental effect of this layered injection technology, the relationships between the different permeability, molecular weight, and concentration of the ASP solution, as well as the resistance coefficient and residual resistance coefficient, are first established, and then, a layered injection experimental model is established to carry out experimental research on injection capacity and oil displacement capacity. The experimental results show that the smaller the range of the core permeability is, the larger the molecular weight and concentration of the ASP solution are, and the poorer the injection capacity of the ASP solution is. After the action of a partial pressure tool and a partial quality tool, the injection capacity of ASP solution is improved to different degrees, and the oil displacement effect of low-permeability cores is significantly improved, while the total oil recovery is increased, and the total oil recovery of heterogeneous cores under different conditions is increased by 1.4%-4.05%. This experiment is of great significance to the study of improving the oil recovery of heterogeneous reservoirs.

KEYWORDS
ASP solution, injection capacity, layered injection, oil recovery, partial pressure tool, partial quality tool

1 | INTRODUCTION

With the continuous exploitation of oil fields, the oil recovery of crude oil decreases and there is more remaining oil in the oil layer. At present, chemical flooding is adopted to improve the oil recovery.1,2 Compared with other chemical flooding methods, ASP (alkali/surfactant/polymer) flooding can effectively improve oil recovery and give full play to oil displacement.3-6 However, most Chinese oil field reservoirs are continental deposits with serious heterogeneity and prominent interlayer contradictions. Under the traditional injection method,7 ASP solution is injected into high-permeability reservoirs in large amounts,8-10 while it is injected into low-permeability reservoirs in small amounts, and the compatibility...
of low-permeability reservoirs with ASP solution is poor,$^{11-13}$ resulting in a poor production degree and low total oil recovery in low-permeability reservoirs. Therefore, in order to improve the total oil recovery of heterogeneous oil layers, a layered injection method which is for the different levels of oil permeability is proposed for Daqing Oilfield, and the method is shown in Figure 1.$^{14,15}$ On the premise of ensuring the oil displacement effect of ASP solution in high-permeability oil layers, partial pressure tools are used to control the injection amount of ASP solution; to increase the injection amount in low-permeability oil layers, partial quality tools are used to improve the injection ability of ASP solution and improve the total oil displacement effect.

In order to solve the problems of limited oil displacement efficiency and low oil recovery caused by reservoir heterogeneity, many scholars have proposed corresponding improvement measures. At present, hydraulic fracturing technology is an important means to develop low-permeability reservoirs. Hydraulic fracturing can form fractures in the formation and significantly increase the permeability in the area near the wellbore. Some scholars have conducted relevant research. Zhou et al.$^{16}$ used microsized proppants to support induced fractures in the fluid fracturing stage and using liquid nanofluids as fracturing fluid additives to improve the oil-water displacement ratio and maximize oil production in low-permeability reservoirs after hydraulic fracturing. Cheng et al.$^{17}$ designed a one-dimensional long core displacement experiment. It was clarified that when fracturing occurred in water injection wells or fractures existed near water injection wells, the equivalent permeability of cores was increased, the pressure transmission was promoted, and the displacement efficiency was improved. The use of hydraulic fracturing fluid directly affects the hydraulic fracturing technology to improve the oil recovery of low-permeability reservoirs. Teklu et al.$^{18}$ used low salinity water added with surfactant self-absorption as hydraulic fracturing fluid and enhanced oil recovery fluid for evaluation in liquid-rich shale reservoirs. Experiments show that the use of this fracturing fluid further improves the oil production of tight oil reservoirs, and these fluids can be used to reduce matrix-fracture skin damage.

Many studies have shown that gas injection in low-permeability reservoirs has better driving force and can improve the development efficiency of low-permeability reservoirs.$^{19-21}$ Because CO$_2$ can be dissolved in oil, which can significantly reduce interfacial tension and oil viscosity, can improve the fluidity ratio of CO$_2$ flooding, and has good injectivity and displacement, CO$_2$ flooding is becoming more and more important in the development of low-permeability reservoirs.$^{22}$ Some scholars have studied CO$_2$ flooding in low-permeability reservoirs; Jin et al.$^{23,24}$ carried out experimental and theoretical research on CO$_2$ flooding of dense Bakken shale. The results show that CO$_2$ injection has good diffusion capacity and accompanying injection capacity and is an effective method for enhancing oil recovery, which can be used continuously after initial oil production. Zhou et al.$^{25}$ used CO$_2$ injection technology to conduct simulation tests and numerical
simulation research on a tight oil reservoir. The test results show that the CO₂ flooding technology greatly improves the oil recovery of the tight formation, increasing the oil recovery to 38.96%.

For oil layers with strong heterogeneity, plugging pores with gel by the profile control method can control the injection amount of displacement agent in high-permeability oil layers, increase the injection amount in low-permeability oil layers, and improve the total oil recovery. Some scholars have studied the profile control method. Cao et al. studied the relationship between the viscosity and fluidity of profile control and oil displacement agent. The results show that injecting profile control and oil displacement agent into the depth of a high-permeability layer can improve the oil recovery. Liu et al. developed dispersed particle gel (DPG) as a new profile control agent and conducted a parallel sand bag test and a microscopic visualization test. The experimental results show that DPG particles can block the high-permeability layer by accumulating in the large pore space or by directly blocking the small pore throat, and can perform in-depth profile control to improve the oil recovery.

Although the above method can effectively improve the oil recovery of low-permeability oil layers, there are still many deficiencies. For hydraulic fracturing technology, only a small part of the injected fracturing fluid can be recovered, and most of the injected fracturing fluid remains in the formation, and the remaining fracturing fluid plugs the original connected pores and throats, resulting in a decrease in physical permeability. In addition, the residual fracturing fluid may form two-phase seepage resistance and reduce the effective permeability of the oil phase; for CO₂ flooding, CO₂ injection may bypass the remaining oil zone and tend to flow through fractures, resulting in low sweep efficiency; for profile control, the injected gel permanently blocks the high-permeability layer. In addition, the flexibility of the gel allows it to enter the low-permeability layer and remain in the matrix, thus causing contamination in the low-permeability region. Therefore, it is of great research significance to propose a layered injection method, which can improve the injection effect of the displacement agent in heterogeneous reservoirs and enhance the total oil recovery by using partial pressure tools and partial quality tools without changing the original formation structure and polluting the formation.

In this paper, a layered injection experimental model is established. Firstly, the relationship between different cores permeability, ASP solution molecular weight and solution concentration, resistance coefficient, and residual resistance coefficient is determined, and the standard of ASP solution injection capacity is established. Then, an oil displacement experiment and an injection capacity experiment of layered injection are carried out for ASP flooding. According to the established ASP solution injection capacity standard, the injection capacity of ASP solutions with different molecular weights and concentrations into heterogeneous cores before and after the action of partial pressure tools and partial quality tools is characterized, and the total oil displacement effect is analyzed, which verifies the effect of layered injection technology on enhancing the oil recovery of heterogeneous oil layers.

2 METHODS AND MATERIALS

2.1 Cores

The core used in the experiment is synthetic core (provided by Daqing Oilfield Research Institute of Mining and Research Engineering). The cores are made of quartz sand, clay, and epoxy resin. Synthetic cores with permeabilities of 50 × 10⁻³ μm², 100 × 10⁻³ μm², 300 × 10⁻³ μm², 400 × 10⁻³ μm², 500 × 10⁻³ μm², 700 × 10⁻³ μm², and 900 × 10⁻³ μm² were prepared by changing the particle size of quartz sand and the content of epoxy resin, respectively. Synthetic cores with specifications of 2.5 × 2.5 × 10 cm were used for experimental research on injection capacity, and synthetic cores with specifications of 4.5 × 4.5 × 30 cm were used for experimental research on oil displacement capacity.

2.2 Brine

In order to truly simulate the oil displacement effect of Daqing Oilfield, ASP solution was prepared by diluting the solution with injected brine, and formation brine was used for core saturation in core displacement experiments. Both the injected brine and formation brine are taken from the No. 1 Oil Production Plant of Daqing Oilfield and must be filtered by a filter membrane (the precision is 0.45 μm) before use. The composition of injected brine and formation brine is shown in Table 1.

| Component brine type | NaCl | KCl | CaCl₂ | MgSO₄ | Na₂SO₄ | NaHCO₃ | Total dissolved solid |
|----------------------|------|-----|-------|-------|--------|--------|----------------------|
| Injection brine (mg/L) | 1029 | 418 | 254   | 135   | 102    | 163    | 2101                 |
| Formation brine (mg/L) | 2186 | 729 | 289   | 198   | 202    | 236    | 3840                 |

TABLE 1 Composition of the injection and the formation brines
2.3 | Experimental oil

Crude oil from the oil field was added into aviation kerosene to prepare the displacement test oil (provided by the No. 1 Oil Production Plant of Daqing Oil Field). Crude oil needs degassing and dehydration before preparation. The viscosity of the experimental oil at 45°C is 8.0 mPa s.

2.4 | ASP solution

The polymer used to prepare the ASP solution in this experiment is partially hydrolyzed polyacrylamide (HPAM), with relative molecular weights of 1200 × 10⁴, 1600 × 10⁴, 1900 × 10⁴, and 2500 × 10⁴, respectively, and the degree of hydrolysis is about 26%, which was provided by Daqing Oilfield Production Technology Research Institute. The surfactant is ORS-41 (alkylbenzene sulfonate) with a mass content of 0.3%, which was provided by Daqing Petroleum Refining and Chemical Company of China. Alkali is Na₂CO₃ with a mass content of 1.2%, which was provided by Daqing Oilfield Oil Production Engineering Research Institute. The ASP solutions were then diluted to concentrations of 1000 mg/L, 1500 mg/L, 2000 mg/L, and 2500 mg/L, respectively, with injected brine, and the preparation process was maintained at 45°C.

2.5 | Partial pressure tool

The partial pressure tool used in the experiment is made of 316L stainless steel (provided by Daqing oil production research institute). The partial pressure tool was developed according to the principle of labyrinth seal. Figure 2 shows the structural model of the partial pressure tool.

The structural parameters of the partial pressure tool selected in the experiment are as follows: the inner diameter of the outer cylinder is 19 mm, the minimum distance between the throttling groove and the outer cylinder is 0.5 mm, the radius of the convex arc is 3 mm, and the radius of the concave arc is 1 mm.

2.6 | Partial quality tool

The partial quality tool used in the experiment is made of 316L stainless steel (provided by Daqing Oil Production Research Institute). The surface of the partial quality tool is smooth, and the surface of the runner is required to be polished smooth.

Figure 3 shows a structural model of the partial quality tool, which is mainly divided into a contraction section, a cylinder section, and a diffusion section, and the middle part of the tool is a region through which the solution flows. The flow of the ASP solution in the partial quality tool can be regarded as a flow process of shrinking first and then expanding in a
variable cross-sectional pipeline. The structural parameters of the partial quality tool in the experiment are as follows: the radius of the contraction section is 5 mm, the length of the contraction section is 3 mm, the length of the cylinder section is 2 mm, the length of the diffusion section is 1 mm, and the radius of the diffusion section is 3 mm.

2.7 | Experimental study on injection capacity

The experimental flow of layered injection is shown in Figure 4. In order to simulate the real experimental environment, in the experiment, except the injection system, other equipment was placed in a thermostat at a temperature of 45°C.

Core 1 and core 2 in Figure 4 replace cores with different permeabilities according to experimental requirements. The concentration and molecular weight of the ASP solution in piston container 1 are changed according to the experimental requirements, and the partial pressure tool and partial quality tool in chemical injector 1 and chemical injector 2 are installed or not installed according to the experimental requirements. Cross-sectional views of chemical injectors, 1 and 2, in which the partial pressure tool and the partial quality tool are installed, are shown in Figures 5 and 6.

Experimental study on the injection capacity of ASP solution:

1. Vacuum cores 1 and 2 with different permeabilities for about 2 hours.
2. Cores 1 and 2 are placed in parallel in a core holder, treated at a constant temperature of 45°C for 24 hours, and then injected with formation water at a flow rate of 0.2 mL/min by using a constant-flux pump, saturated for more than 4 hours, and then, the inflow volume and outflow volume of formation water are measured, and the pore volume of the core is calculated.
3. After water flooding, record the pressure difference between cores 1 and 2.
4. ASP solutions of different molecular weights and concentrations are injected with a constant-flux pump at an average flow rate of 0.2 mL/min to record the pressure difference across cores 1 and 2. In order to prevent channeling, the annular pressure is always 2 MPa higher than the injection pressure during the injection process.
5. After ASP solution injection is completed, water flooding is carried out subsequently. Calculate the resistance coefficient and residual resistance coefficient.
6. After installing the partial pressure tool and the partial quality tool in chemical injectors 1 and 2, respectively, repeat the above experimental steps. Calculate the resistance coefficient and residual resistance coefficient.

2.8 | Experimental study on oil displacement capacity

On the basis of the experimental study of injection capacity, the oil displacement experiment of ASP solution is carried out:

1. Vacuum cores 1 and 2 with different permeabilities until the vacuum degree reaches 98% for more than 2 hours and measure the pore volume of cores when the cores are saturated with formation water.
2. Each core is placed in a core holder, and the test oil is saturated to 2 PV at 45°C. At the same time, the condition is...
3. Layered injection is adopted for water flooding until the comprehensive water cut at the outlets of cores 1 and 2 reaches 98%, and pressure change, liquid production, water production, and oil production are collected, respectively.

4. Inject ASP solution slugs with different molecular weights and concentrations for displacement, respectively, and collect the pressure changes, fluid production, water production, and oil production after displacement until the comprehensive water cut at the core outlet is more than 98%.

5. Calculate the oil recovery and total oil recovery at each core stage.

6. After installing the partial pressure tool and partial quality tool in the chemical injector, repeat the above experimental steps. Calculate the oil recovery and total oil recovery at each core stage.

2.9 | Evaluation parameters

When ASP solution flows through the porous medium of the core, it causes fluidity change, and this effect can be described by the resistance coefficient. The resistance coefficient is the ratio of water fluidity to ASP solution fluidity:

$$ R_F = \frac{\lambda_w}{\lambda_p} = \frac{K_w/\mu_w}{K_p/\mu_p} $$

(1)

where $\lambda_w$ is the fluidity of water; $\lambda_p$ is the fluidity of the ASP system; $K_w$ is the core water phase permeability, in $\mu$m$^2$; $K_p$ is the core ASP phase permeability, in $\mu$m$^2$; $\mu_w$ is the viscosity of water in porous media, in mPa s; and $\mu_p$ is the viscosity of the ASP solution, in mPa s.

When ignoring the viscoelastic effect, if the length of the porous medium is constant and the flow rate of the solution and water in the ASP system is constant, the above formula can be changed into:
where \( \Delta P \) is the pressure drop at both ends before and after the fluid flows through the core, in MPa; \( L \) is the core length, in m; and \( V \) is volume flow, in m\(^3\)/d.

However, if the length of the porous medium is constant and the flow rate of the solution and water in the ASP system is constant, then there is:

\[
R_F = \frac{(\Delta P)_p}{(\Delta P)_w} \quad (2)
\]

This formula is the formula for determining the resistance coefficient by the experimental method. In order to characterize the lasting drop effect of permeability caused by the ternary system solution flowing through porous media, the residual resistance coefficient \( R_{FF} \) is introduced:

\[
R_{FF} = \frac{K_{wb}}{K_{wa}} \quad (3)
\]

where \( K_{wb} \) is the permeability of water flooding before the injection of the ASP system, in \( \mu m^2 \); and \( K_{wa} \) is the water flooding permeability after injecting the ASP system, in \( \mu m^2 \).

In the process of oil displacement, the displacement agent must have good transportation, migration, and retention properties so as to penetrate into the reservoir and realize fluid diversion in deeper areas. Therefore, a good match between the displacement agent and the pore throat is very important. \(^{42-44}\) When ASP solution is used as a displacement agent, attention should be paid not only to the ability of the polymer to increase viscosity, but also to the potential mismatch between the diameter of polymer aggregates and the pore throat size of the reservoir, because a poor matching relationship leads to polymer molecules remaining mainly in the reservoir area near the injection well and poor injection capacity. However, the larger the sweep efficiency of the ASP solution is, the more effective the ASP solution can be in blocking large channels and therefore the larger the resistance coefficient is. The better the effect of the ASP solution in reducing the seepage capacity of the high-permeability oil layer, the greater the retention of the ASP solution in the pore canal and therefore the greater the residual resistance coefficient. When the residual resistance coefficient is too large, the ASP solution partially or completely blocks the pores. \(^{45,46}\) Therefore, compatibility between the ASP solution and the core is comprehensively evaluated according to the resistance coefficient and residual resistance coefficient.

### 3 RESULTS AND DISCUSSION

#### 3.1 ASP solution injection capacity standard

In the past, many scholars have studied and summarized the relationship between core injection capacity and relevant parameters such as pressure difference, resistance coefficient, and residual resistance coefficient through a large number of core displacement experiments. The injection capacity is judged from the stability degree of pressure, resistance coefficient, and residual resistance coefficient with the increase in injected PV number, and it is generally believed that the injection capacity of the displacement agent is poor when the injection pressure is high and good when the injection pressure is low. \(^{47-49}\) but these evaluation standards only analyze the injection situation from the total change trend, and there is no accurate range to specifically define the injection capacity for the actual displacement situation. According to these related research studies and combined with the main parameters such as injection pressure and produced fluid, 38 groups of experiments were carried out through laboratory experiments. The injection capacity of ASP solutions with different concentrations and different molecular weights in cores with different permeability is shown in Table 2. According to the results in Table 2, a comprehensive index for judging the injection capacity is established, as shown in Table 3.

According to the results in Table 2, the judgment standards in Table 3 are formulated. In this paper, the injection capacity of the ASP solution in cores is divided into three grades from the angle of the resistance coefficient and residual resistance coefficient according to the layered injection flooding experiment. Each grade is divided according to a certain range of resistance coefficient and residual resistance coefficient.

Based on the above analysis, the following results are obtained:

With the increase of resistance coefficient and residual resistance coefficient, the injection capacity of ASP system decreases. Oil layers with permeability below \( 100 \times 10^{-3} \mu m^2 \) have poor matching with various ASP solutions. Oil layer with permeability \( (300-400) \times 10^{-3} \mu m^2 \) is suitable for injection of ASP solutions with \( 1200 \times 104 \) molecular weight and low concentration polymers. Oil layer with permeability \( (400-500) \times 10^{-3} \mu m^2 \) is suitable for injection of ASP solutions with molecular weight of \( 1900 \times 10^4 \) and below. When ASP solution with high molecular weight polymer is used, higher concentration is not suitable. Oil layers with permeability of \( 700 \times 10^{-3} \mu m^2 \) or more are suitable for ASP solutions with high molecular weight and high concentration polymers. The molecular weight of \( 2500 \times 10^4 \) is generally poor for injection into various permeability reservoirs.
3.2 Effect of core permeability on ASP solution injection capacity and oil displacement

In the layered injection experiment, ASP solutions with a concentration of 1500 mg/L and a molecular weight of $1600 \times 10^4$ before and after the action of the partial pressure tool and partial quality tool are injected at an average flow rate of 0.1 mL/min into cores with different permeability. The permeability of high-permeability reservoir to low-permeability reservoir is defined as permeability ratio. The

### TABLE 2

Compatibility of molecular weight, concentration, and core permeability in the ASP solution system

| Number | Permeability ($\times 10^{-3}$ μm²) | Concentration (mg/L) | Molecular weight ($\times 10^4$) | Resistance coefficient | Residual resistance coefficient | Injection pressure | Injection capacity |
|---|---|---|---|---|---|---|---|
| 1 | 50 | 1000 | 1900 | 145 | 26.6 | High | Poor |
| 2 | 50 | 1500 | 1600 | 130 | 22.4 | High | Poor |
| 3 | 50 | 2000 | 1200 | 135 | 25.7 | High | Poor |
| 4 | 100 | 1000 | 1900 | 108.9 | 24.1 | High | Poor |
| 5 | 100 | 1500 | 1900 | 117.8 | 27.3 | High | Poor |
| 6 | 100 | 2000 | 1200 | 100.4 | 20.5 | High | Poor |
| 7 | 100 | 2000 | 1600 | 110.5 | 23.8 | High | Poor |
| 8 | 100 | 2500 | 1200 | 112.5 | 25.7 | High | Poor |
| 9 | 300 | 2500 | 1600 | 82.7 | 21 | High | Poor |
| 10 | 300 | 2000 | 1900 | 94.4 | 20.3 | High | Poor |
| 11 | 300 | 1500 | 1600 | 62.4 | 15.5 | Middle | Middle |
| 12 | 300 | 1000 | 1900 | 67 | 16.9 | Middle | Middle |
| 13 | 300 | 1500 | 1900 | 72.5 | 18.6 | Middle | Middle |
| 14 | 300 | 1000 | 1200 | 48.9 | 11.4 | Low | Good |
| 15 | 300 | 1500 | 1200 | 57.7 | 12.9 | Low | Good |
| 16 | 400 | 2000 | 1900 | 83.2 | 20.4 | High | Poor |
| 17 | 400 | 2500 | 1900 | 84.3 | 22.5 | High | Poor |
| 18 | 400 | 1500 | 1900 | 65.1 | 17.5 | Middle | Middle |
| 19 | 400 | 2500 | 1200 | 66 | 16.3 | Middle | Middle |
| 20 | 400 | 1000 | 1200 | 45.2 | 9.5 | Low | Good |
| 21 | 400 | 2000 | 1200 | 57.3 | 13.8 | Low | Good |
| 22 | 500 | 1000 | 2500 | 64.2 | 16 | Middle | Middle |
| 23 | 500 | 2000 | 1900 | 78.4 | 18.3 | Middle | Middle |
| 24 | 500 | 1000 | 1600 | 45.6 | 8.5 | Low | Good |
| 25 | 500 | 1500 | 1600 | 50.1 | 9.8 | Low | Good |
| 26 | 500 | 2000 | 1200 | 53.8 | 10.7 | Low | Good |
| 27 | 500 | 2000 | 1600 | 59.5 | 11.3 | Low | Good |
| 28 | 700 | 2500 | 1900 | 75 | 15.6 | Middle | Middle |
| 29 | 700 | 1000 | 1600 | 39.4 | 7.2 | Low | Good |
| 30 | 700 | 1000 | 1900 | 48.7 | 11.3 | Low | Good |
| 31 | 700 | 1500 | 1600 | 46.6 | 8 | Low | Good |
| 32 | 700 | 2000 | 1600 | 48.2 | 9.4 | Low | Good |
| 33 | 700 | 2500 | 1200 | 53.4 | 10.3 | Low | Good |
| 34 | 900 | 1000 | 1200 | 31 | 5.3 | Low | Good |
| 35 | 900 | 1000 | 2500 | 49 | 13.2 | Low | Good |
| 36 | 900 | 1500 | 1600 | 40.7 | 6.2 | Low | Good |
| 37 | 900 | 2000 | 1900 | 58.3 | 11.6 | Low | Good |
| 38 | 900 | 2500 | 1600 | 57.2 | 9.5 | Low | Good |
variation of the resistance coefficient and residual resistance coefficient is shown in Figure 7.

As can be seen from Figure 7, under the condition of injecting ASP solution with the same concentration and molecular weight, the residual resistance coefficient decreases as the permeability of cores 1 and 2 increases. This is because the lower the permeability of the core, the greater the retention of the polymer in it, and the ratio of the effective size of polymer molecules to the pore size of the core also increases, thus increasing the shrinkage rate of its pores. Therefore, the residual resistance coefficient increases with the decrease in core permeability, and the resistance coefficient decreases with the increase in permeability of cores 1 and 2. This is because the core with high-permeability has a larger pore throat radius, and the resistance of the solution flowing in it is small, so the resistance coefficient is small.

For core 1, the injection amount of ASP solution in core 1 is controlled after the action of the partial pressure tool. While ensuring the oil displacement effect of ASP solution in core 1, ASP solution is injected into core 2 with low permeability as much as possible. The larger the permeability is, the more obvious the control effect of the ASP solution injection amount is. The greater the reduction degree of relative injection volume of core 1, the smaller the shearing degree and retention volume of ASP solution in the core flow process, and correspondingly, the resistance coefficient and residual resistance coefficient are both reduced.

**TABLE 3** Injection capacity standard

| Characteristic       | Good | Middle | Poor |
|---------------------|------|--------|------|
| Resistance coefficient | <60  | 60-80  | >80  |
| Residual resistance coefficient | <15  | 15-20  | >20  |

**FIGURE 7** Variation of the resistance coefficient and residual resistance coefficient under different permeability: (A) resistance coefficient of core 1 under different permeability; (B) residual resistance coefficient of core 1 under different permeability; (C) resistance coefficient of core 2 under different permeability; (D) residual resistance coefficient of core 2 under different permeability
As for core 2, due to the effect of the partial pressure tool, the injection amount into core 2 is increased compared with that without the partial pressure tool, and after the partial quality tool is applied, the ASP solution is subjected to shearing action and tensile stress to generate the shearing degradation effect, so that short chains and long molecular chains with polar groups in the ASP solution are sheared to fracture, and the molecular chains easily curl and wind together to form irregular spatial structures. The ability of this spatial structure to wrap water molecules is greatly reduced, resulting in a decrease in viscosity increasing ability, which is macroscopically represented by a decrease in the viscosity of the solution, so that the injection capacity of the ASP solution in low-permeability cores is enhanced, and the resistance coefficient and residual resistance coefficient are reduced.

As the permeability ratio increases, the heterogeneity increases. In the process of layered injection, the more obvious the effect of the partial pressure tool and the partial quality tool is, the lower the resistance coefficient and residual resistance coefficient are. When the permeability ratio is the largest, the resistance coefficient and residual resistance coefficient of core 1 are reduced by 33.4% and 36.8%, respectively, under the action of the partial pressure tool, while the resistance coefficient and residual resistance coefficient of core 2 are reduced by 39.3% and 43.4%, respectively, under the action of the partial quality tool. According to the judgment standard of injection capacity, it is shown that the injection effect of ASP solution is developing in a better direction, and the larger the permeability ratio is, the better the injection effect is, and the effect of the partial quality tool on improving the injection capacity of ASP solution is stronger than that of the partial pressure tool.

Oil displacement experiments were conducted on the basis of the above-mentioned analysis of injection capacity impact, and the oil recovery of cores 1 and 2 before and after the action of the partial pressure tool and the partial quality tool were measured through layered injection oil displacement experiments under different permeability. The results are shown in Table 4.

As can be seen from Table 4, with the increase in permeability ratio, the oil recovery of core 1 increases and the oil recovery of core 2 decreases. This is because with the increase in permeability ratio, the higher the matching degree of the ASP solution to pores in high-permeability core 1, the more the injection amount, resulting in a better oil displacement effect, while the smaller the amount of ASP solution flowing into low-permeability core 2, and the lower the matching degree to the pores of the core, resulting in a lower oil recovery, the greater the permeability ratio, and the greater the reduction degree. After the action of the partial pressure tool, the oil recovery of core 1 decreases. This is because the more obvious the effect of the partial pressure tool is as the

| Permeability ratio | Total oil recovery of core 1 before the action of the partial pressure tool (%) | Total oil recovery of core 1 after the action of the partial pressure tool (%) | Total oil recovery of core 2 before the action of the partial pressure tool (%) | Total oil recovery of core 2 after the action of the partial pressure tool (%) |
|-------------------|---------------------------------|---------------------------------|---------------------------------|---------------------------------|
| 1                 | 30.6                            | 29.6                            | 34.5                            | 31.8                            |
| 3                 | 34.5                            | 34.7                            | 34.7                            | 34.7                            |
| 4                 | 28.8                            | 27.3                            | 36.3                            | 33.2                            |
| 5                 | 39.4                            | 44                              | 44                              | 31.4                            |
| 7                 | 51.3                            | 47.6                            | 47.6                            | 31.8                            |
| 9                 | 56.5                            | 54.9                            | 56.5                            | 28.6                            |
permeability ratio increases, the injection amount of the ASP solution into the high-permeability core is controlled. On the premise of ensuring the oil displacement efficiency of the high-permeability core, the injection amount of ASP solution into the low-permeability core increases and the injection amount of the high-permeability core decreases, resulting in a slight decrease in oil recovery. Although the oil recovery of core 1 is slightly decreased, the injection amount of the low-permeability core increases after the action of the partial pressure tool, and the injection capacity of ASP solution is enhanced after the action of the partial quality tool, so that the oil recovery of core 2 is greatly increased, resulting in an increase in the total average oil recovery. Therefore, when the permeability ratio is extremely large, the partial pressure tool and the partial quality tool can be used to improve the oil recovery.

3.3 Effect of molecular weight of ASP solution on injection capacity and oil displacement

In the layered injection experiment, ASP solutions with different molecular weights \(1200 \times 10^4, 1600 \times 10^4, 1900 \times 10^4, 2500 \times 10^4\) and concentrations of 1500 mg/L before and after the action of the partial pressure tool and the partial quality tool are injected into cores with a permeability ratio of 5 at an average flow rate of 0.1 mL/min. The variation of the resistance coefficient and the residual resistance coefficient is shown in Figure 8.

As can be seen from Figure 8, under the condition of the same permeability ratio and the same concentration of injected ASP solution, the resistance coefficient and residual resistance coefficient increase with the increase in...
solution molecular weight. This is because when the molecular weight of the polymer in the ASP solution increases, and the effective volume of its molecules in the solution increases, the longer the macromolecular chain is, the more easily the molecular chain is entangled, the more stable the conformation of the molecular chain is, and the formed reticular entanglement points are firmer, so its viscosity is also larger, resulting in an increase in the flow resistance of the solution. Furthermore, the high molecular weight may promote the mechanical trapping behavior of polymer molecules on the pore surface of the core, which increases the retention of the polymer in the porous medium, so the resistance coefficient and residual resistance coefficient increase with the increase in the molecular weight of the solution.

For core 1, when the permeability ratio reaches 5, most of the ASP solution injected is injected into core 1 with high permeability due to the existence of the permeability ratio before the action of the partial pressure tool, resulting in a higher resistance coefficient and residual resistance coefficient in core 1. After the action of the partial pressure tool, the injection amount of the high-permeability core is relatively reduced, the ASP solution flowing into the low-permeability core increases, and the flow resistance and trapping ability in core pores increase. Therefore, after the action of the partial pressure tool, the resistance coefficient and residual resistance coefficient of core 1 are both reduced; however, the degree of decrease changes little with the increase in molecular weight.

For core 2, before the action of the partial pressure tool and the partial quality tool, less ASP solution flows into core 2, and the injection capacity of the solution to the low-permeability core is not strong, resulting in a larger resistance coefficient and residual resistance coefficient in the core pores. After the action of the partial pressure tool and the partial quality tool, although the injection amount of ASP solution into core 2 increases, the partial quality tool has a stronger effect on improving the matching degree of ASP solution in the low-permeability core, so after the action of the partial quality tool, both the resistance coefficient and the residual resistance coefficient decrease.

By comparing the effects of the partial pressure tool and the partial quality tool, with the increase of molecular weight of ASP solution injected, the reduction degrees of the resistance coefficient and residual resistance coefficient by the partial quality tool are larger; the reduction degrees of the resistance coefficient and residual resistance coefficient are 24.8% and 32.5% respectively, while the reduction degrees of the resistance coefficient and residual resistance coefficient by the partial pressure tool are 9.3% and 7.4%, respectively. Therefore, when the molecular weight of the ASP solution is changed, the effect of improving the solution injection capacity is the best with the partial quality tool.
Oil displacement experiments were conducted on the basis of the above analysis of injection capacity. Under the condition of injecting ASP solutions with different molecular weights, the oil recovery of cores 1 and 2 before and after the action of the partial pressure tool and the partial quality tool was measured through stratified injection oil displacement experiments. The results are shown in Table 5.

As can be seen from Table 5, the oil recovery of core 1 decreases after the action of the partial pressure tool, while the oil recovery of core 2 increases after the action of the partial quality tool. With the increase in molecular weight, the oil recovery also increases. This is because the higher the molecular weight, the coarser the molecular structure and the denser the spatial network structure. The higher the viscosity of the solution, the stronger the displacement effect, so the greater the oil recovery. However, when the molecular weight reaches $2500 \times 10^4$, the oil recovery decreases, which is due to the mismatch between the molecular weight and the injection capacity caused by the excessive molecular weight. The resistance coefficient and residual resistance coefficient decrease after the action of the partial quality tool, the injection capacity of the ASP solution is improved, and the oil displacement effect is enhanced.

Correspondingly, the oil recovery of core 2 is greatly improved, and the oil recovery of the ASP solution with a molecular weight of $2500 \times 10^4$ is increased which is higher than the molecular weight is $1900 \times 10^4$, indicating that the partial quality tool had a better injection effect on improving the high molecular weight ASP solution.
Effect of ASP solution concentration on injection capacity and oil displacement

In the layered injection experiment, ASP solutions with different concentrations (1000 mg/L, 1500 mg/L, 2000 mg/L, 2500 mg/L) and molecular weights of $1600 \times 10^4$ before and after the action of the partial pressure tool and the partial quality tool are injected into cores with a permeability ratio of 5 at an average flow rate of 0.1 mL/min, and the changes in the resistance coefficient and residual resistance coefficient are shown in Figure 9.

As can be seen from Figure 9, under the condition that there is the same permeability ratio and the same molecular weight of ASP solution, the partial pressure tool can reduce the resistance coefficient and residual resistance coefficient while controlling the injection amount, but with the increase in concentration, the partial pressure tool reduces the resistance coefficient and residual resistance coefficient to a greater extent, with the maximum reduction reaching 21.8% and 16%, while the partial quality tool reduces the resistance coefficient and residual resistance coefficient by only 9.3% and 7.4% with the increase in molecular weight. This shows that the change in the ASP solution concentration has a greater influence on the injection capacity of the partial pressure tool.

For core 2, the shearing of the ASP solution with high concentration by the partial quality tool can reduce the resistance coefficient and residual resistance coefficient to improve the injection capacity of the solution, but with the increase in concentration, the improvement in the injection capacity of the solution becomes limited, and the maximum reduction in the resistance coefficient and residual resistance coefficient can only reach 9.7% and 9.3%. However, with the increase in molecular weight, the degree of decreasing the resistance coefficient of the partial quality tool reaches 9% and 7.4%, and the more polymer molecules in pores increases, and the shear stress of the solution increases during core pore flow increases. This is because with the concentration of ASP solution injected increasing, the polymer injected into the core is caused by the adsorption of the polymer on the rock surface and mechanical trapping in pores. The higher the concentration of the solution, the larger the molecular clusters generated between molecules, and the more polymer retain or even block the pores, resulting in an increase in the resistance coefficient.

The results are shown in Table 6.

### Table 6: Oil recovery under different ASP solution concentrations in the layered injection experiment

| Concentration (mg/L) | Total oil recovery of core 1 before the action of the partial pressure tool (%) | Total oil recovery of core 2 before the action of the partial quality tool (%) | Total oil recovery of core 1 after the action of the partial pressure tool (%) | Total oil recovery of core 2 after the action of the partial quality tool (%) |
|----------------------|------------------------------------------|------------------------------------------|------------------------------------------|------------------------------------------|
| 1000                 | 44.7                                     | 27.8                                     | 43.8                                     | 32.1                                     |
| 1500                 | 46.2                                     | 26.1                                     | 44.8                                     | 31.5                                     |
| 2000                 | 48.5                                     | 25.6                                     | 46                                       | 30.9                                     |
| 2500                 | 47.2                                     | 23.9                                     | 44.8                                     | 29.4                                     |
24.8% and 32.5%, which indicates that the change in the ASP solution molecular weight has a greater influence on core 2 under the action of the partial quality tool, that is, compared with changing the ASP solution concentration, the partial quality tool has the best effect on improving the solution injection capacity when the solution molecular weight changes.

Through the effect on the partial pressure tool and the partial quality tool, the partial pressure tool has the best effect on improving the solution injection capacity when changing the ASP solution concentration. The partial quality tool has the best effect on improving the injection capacity of the solution when changing the molecular weight of the ASP solution.

Oil displacement experiments were conducted on the basis of the above analysis of the injection capacity, and the oil recovery of cores 1 and 2 before and after the action of the partial pressure tool and the partial quality tool were measured by layered injection oil displacement experiments under the condition of injecting ASP solutions with different concentrations. The results are shown in Table 6.

It can be seen from Table 6 that when the ASP solution concentration is changed, the oil displacement effect and action mechanism of the partial pressure tool and partial quality tool on cores with permeability are the same as when the ASP solution molecular weight is changed. When the concentration of injected ASP solution increases, the oil recovery of cores 1 and 2 before and after the action of the partial pressure tool and the partial quality tool also increases. However, when the concentration of the solution rises to 2500 mg/L, the oil recovery decreases. This is because the higher the concentration of the solution, the greater the resistance in the injection process, resulting in blocking of the solution in the pores of the core, and weakening of the injection capacity of the solution, affecting the oil displacement effect. The resistance coefficient and residual resistance coefficient are decreased after the action of the partial quality tool, and the injection capacity of the ASP solution is improved. With the increase in concentration, the oil recovery is further increased after passing through the partial pressure tool and the partial quality tool. However, for the ASP solution with a concentration of 2500 mg/L, although the injection capacity is improved, the oil recovery is lower than the ASP solution with a concentration of 2000 mg/L. Therefore, for the layered injection flooding system, the partial pressure tool and the partial quality tool have a poor improvement effect on the ASP solution with an ultrahigh concentration, and the oil displacement efficiency is low. Therefore, the ultrahigh concentration ASP solution should be carefully used in actual production.

4 | CONCLUSIONS

According to laboratory experiments of layered injection, the injection capacity and oil displacement effect of ASP solution in heterogeneous cores are studied, and the following conclusions are obtained:

1. The injection capacity of the ASP solution has a strong relationship with core permeability, solution molecular weight, and concentration. The lower the permeability, the higher the solution molecular weight, the higher the concentration, the greater the resistance coefficient and residual resistance coefficient, and the worse the injection capacity.

2. In the layered injection experiment, both the partial pressure tool and the partial quality tool can effectively improve the injection ability of ASP solution in heterogeneous cores. When the solution concentration changes, the partial pressure tool has the best effect on improving the injection capacity of the ASP solution, and when the solution molecular weight changes, the partial quality tool has the best effect on improving the injection capacity of the ASP solution.

3. The partial pressure tool and the partial quality tool used in the layered injection experimental process can effectively improve the problem of low oil recovery caused by heterogeneity, and the oil recovery is increased by 1.4%-4.05% under different conditions.

4. In the process of oil displacement in heterogeneous reservoirs, an ultrahigh concentration of displacement agent should be carefully used; otherwise, it causes negative increase in the oil recovery.

ACKNOWLEDGMENTS

This work was supported by Daqing Oilfield Oil Production Engineering Research Institute.

CONFLICT OF INTEREST

The authors declare no conflict of interest.

ORCID

Xinyu Hu https://orcid.org/0000-0002-5858-7305

REFERENCES

1. Shiran BS, Skaige A. Enhanced oil recovery (EOR) by combined low salinity water/polymer flooding. Energy Fuels. 2013;27:1223-1235.

2. Feng QH, Chen XC, Sun MD. Study of the multiple-profile control system to enhance oil recovery after polymer flooding. J Pet Explor Prod Technol. 2012;2012(2):133-139.

3. Ehrlich R, Hasiba HH, Raimondi P. Alkaline waterflooding for wettability alteration–evaluating a potential field application. J Petrol Technol. 1974;26(12):1335-1343.

4. Hirasaki GJ, Miller CA, Puerto M. Recent advances in surfactant EOR. SPE J. 2011;16:889-907.

5. Liu S, Zhang DL, Yan W, Puerto M, Hirasaki GJ, Miller CA. Favorable attributes of alkaline–surfactant–polymer flooding. SPE J. 2008;13:5-16.
6. Xie YY, Hou JR, Zhang JZ, Xie DH, Ren F, Zhang Y. Evaluation of low-concentration surfactant system for chemical flooding. *Pet Geol Recover Effic*. 2014;1:74-77.

7. Li S, Zhao J, Cui P, Yang J, Chen W. Strategies of development technology for ultralow permeability reservoir. *Lithol Reserv*. 2008;20:128-131.

8. Guo YJ, Liang Y, Cao M. Flow behavior and viscous-oil-micro-displacement characteristics of hydrophobically modified partially hydrolyzed polyacrylamide in a repeatable quantitative visualization micromodel. *SPE J*. 2017;22:1448-1466.

9. Lu XG, Wang XY, Jiang WD. Experimental study on the molecular dimension and configuration of polymer and its flow characteristics from electrolyte effect. *Chin J Chem*. 2009;27:839-845.

10. Lu XG, Zhao LL, Zhang K. The effect and analysis on Cr^{3+} gel improvement profile control in alkalenesialkane/surfactant/polymer flooding. *J Appl Polym Sci*. 2009;112:2773-2780.

11. Zhang JA, Wang SX, Lu XG, He XH. Performance evaluation of oil displacing agents for primary-minor layers of the Daqing Oilfield. *Petrol Sci*. 2011;8:79-86.

12. Dai CL, Yang S, Wu XP, et al. Investigation on polymer reutilization mechanism of salt tolerant modified starch on offshore oilfield. *Energy Fuels*. 2016;30:5585-5592.

13. Zhang J, Ai C, Li YW, Che MG, Cao R, Zeng J. Energy-based brittleness index and acoustic emission characteristics of anisotropic coal under triaxial stress condition. *Rock Mech Rock Eng*. 2018;51:3343-3360.

14. He WY, Liu LC. Study and application on layered polymer injection with concentric string. *Adv Mater Res*. 2012;537:1135-1141.

15. Jalali M, Embry JM, Sanfilippo F, Santarelli FJ, Dusseault MB. Cross-flow analysis of injection wells in a multilayered reservoir. *Petroleum*. 2016;2:273-281.

16. Zhou FJ, Su H, Liang XY, Meng LF, Yuan LH, Liang TB. Integrated hydraulic fracturing techniques to enhance oil recovery from tight rocks. *Petrol Explor Develop*. 2019;46:1065-1072.

17. Cheng LS, Wang DQ, Cao RY, Xia RF. The influence of hydraulic fractures on oil recovery by water flooding processes in tight oil reservoirs: an experimental and numerical approach. *J Pet Sci Eng*. 2020;185:106572.

18. Teklu TW, Li XP, Zhou Z, Alharthy N, Wang L, Abass H. Low-salinity water and surfactants for hydraulic fracturing and EOR of shales. *J Petrol Sci Eng*. 2018;162:367-377.

19. Jiang YW, Zhang YT, Liu SQ. Oil displacement mechanism of air injection of low permeability reservoir development. *J Pet Explor Dev*. 2010;37:471-476.

20. Faure P, Landais P. Evidence for clay minerals catalytic effects during low temperature air oxidation of n-alkanes. *J Fuel*. 2000;79:1751-1756.

21. Zhang X, Liu JY, Sun LT, Li SL, Liu WH. Research on the mechanisms of enhancing recovery of light-oil reservoir by air-injected low-temperature oxidation technique. *Nat Gas Ind*. 2004;24:78-80.

22. Xiao P, Yang Z, Wang X, Xiao H, Wang X. Experimental investigation on CO_{2} injection in the Daqing extra-ultra-low permeability reservoir. *J Pet Sci Eng*. 2016;149:765-771.

23. Jin J, Hawthorne S, Sorensen J, et al. Advancing CO_{2} enhanced oil recovery and storage in unconventional oil play—experimental studies on Bakken shales. *Appl Energy*. 2017;208:171-183.

24. Jin L, Sorensen JA, Hawthorne SB, et al. Improving oil recovery by use of carbon dioxide in the bakken unconventional system: a laboratory investigation. *SPE Reserv Eval Eng*. 2017;20:602-612.

25. Zhou X, Yuan QW, Zhang YZ, Wang JY, Zeng FH, Zhang LH. Performance evaluation of CO_{2} flooding process in tight oil reservoir via experimental and numerical simulation studies. *Fuel*. 2019;236:730-746.

26. Dai JD, Pu WF, Tan X, Liu R. Experimental study of secondary crosslinking core-shell hyperbranched associating polymer gel and its profile control performance in low-temperature fractured conglomerate reservoir. *J Pet Sci Technol*. 2019;179:912-920.

27. Cao WJ, Xie K, Lu XG, Liu YG, Zhang YB. Effect of profile-control oil-displacement agent on increasing oil recovery and its mechanism. *Fuel*. 2019;237:1151-1160.

28. Liu YF, Dai CL, Kai W, Gao MW, Yang Z, Wu YN. Investigation on preparation and profile control mechanisms of the dispersed particle gels (DPG) formed from phenol-formaldehyde cross-linked polymer gel. *Ind Eng Chem Res*. 2016;55:6284-6292.

29. Zhou Z, Abass H, Li X, Teklu T. Experimental investigation of the effect of imibition on shale permeability during hydraulic fracturing. *J Nat Gas Sci Eng*. 2016;29:413-430.

30. Harrison AL, Jew AD, Dustin MK, et al. Element release and reaction-induced porosity alteration during shale-hydraulic fracturing fluid interactions. *Appl Geochem*. 2017;82:47-62.

31. Liang T, Longoria RA, Lu J, Nguyen QP, DiCarlo DA. Enhancing hydrocarbon permeability after hydraulic fracturing: laboratory evaluations of shut-ins and surfactant additives. *SPE J*. 2017;22:1011-1023.

32. Ahmad M, Sharma MM, Pope G, Torres DE, McCulley CA, Limmeney H. Chemical treatment to mitigate condensate and water blocking in gas wells in carbonate reservoirs. *SPE Prod Oper*. 2011;26:67-74.

33. Zhao F, Zhang L, Hou J, Cao S. Profile improvement during CO_{2} flooding in ultralow permeability reservoirs. *Pet Sci*. 2014;11:279-286.

34. Gao Y, Zhao M, Wang J, Chang Z. Performance and gas breakthrough during CO_{2} immiscible flooding in ultra-low permeability reservoirs. *Pet Explor Dev*. 2014;41:88-95.

35. Song Z, Hou J, Liu X, Wei Q, Hao H, Zhang L. Conformance control for CO_{2}-EOR in naturally fractured low permeability oil reservoirs. *Petrol Sci*. 2018;66:225-334.

36. Yasov AM, Bulagkova GT. Modeling of the installation and stability of gel barriers in main fractures. *J Appl Mech Tech Phys*. 2018;59:359-367.

37. Wang J, Liu HQ, Zhang J, et al. Experimental investigation on water flooding and continued EOR techniques in buried-hill metamorphic fractured reservoirs. *J Petrol Sci Eng*. 2018;171:529-541.

38. You Q, Wen Q, Fang J, Guo M, Zhang Q, Dai C. Experimental study on lateral flooding for enhanced oil recovery in bottom-water reservoir with high water cut. *J Petrol Sci Eng*. 2019;174:747-756.

39. Stoffa H. Incompressible flow in a labyrinth seal. *J Fluid Mech*. 1980;100:817-829.

40. Vermes G. A Fluid mechanics approach to the labyrinth seal leakage problem. *J Eng Power*. 1961;83:161-169.

41. Rhode DL, Sobolik SR. Simulation of subsonic flow through a generic labyrinth seal. *J Eng Power*. 1986;108:674-680.

42. Zhao XQ, Pan F, Guan WT. A novel method of optimizing the molecular weight of polymer flooding. In: *Proceedings of the SPE Enhanced Oil Recovery Conference, Lumpur, Malaysia*. 2011.

43. Luo WL, Ma DS, Nie X. Study on matching relation between polymer molecular size and pore size for conglomerate reservoir. In:
Proceedings of the International Petroleum Technology Conference, Beijing, China; 2013.

44. Huang B, Zhang W, Xu R, et al. A study on the matching relationship of polymer molecular weight and reservoir permeability in ASP flooding for Duanxi reservoirs in Daqing Oil Field. Energies. 2017;10:951.

45. Andrzej S, Sławomir G, Kornelia MB. Resistance coefficients of polymer membrane with concentration polarization. Transp Porous Med. 2012;95:151-170.

46. Lake LW, Johns RT, Rossen WR, Pope GA. Fundamentals of Enhanced Oil Recovery. Richardson, TX: Society of Petroleum Engineers; 2014.

47. Xie K, Cao B, Lu XG, et al. Matching between the diameter of the aggregates of hydrophobically associating polymers and reservoir pore-throat size during polymer flooding in an offshore oilfield. J Petrol Sci Eng. 2019;177:558-569.

48. Wang ZH, Le XP, Feng YG, Zhang CX. The role of matching relationship between polymer injection parameters and reservoirs in enhanced oil recovery. J Petrol Sci Eng. 2013;111:139-143.

49. Zhang Y, Feng YJ, Li B, Han PH. Enhancing oil recovery from low-permeability reservoirs with a self-adaptive polymer: a proof-of-concept study. Fuel. 2019;251:136-146.

50. Zhong HY, Zhang WD, Fu J, Lu J, Yin HJ. The performance of polymer flooding in heterogeneous type II reservoirs—an experimental and field investigation. Energies. 2017;10:454.

51. Martin FD. Mechanical degradation of polyacrylamide solutions in core plugs from several carbonate reservoirs. SPE Formation Eval. 1986;1:139-150.

52. Odell JA, Muller AJ, Narh KA, Keller A. Degradation of polymer-solutions in extensional flows. Macromolecules. 1990;23:3092-3103.

53. Muller AJ, Odell JA, Carrington S. Degradation of semidilute polymer-solutions in elongational flows. Polymer. 1992;33:2598-2604.

54. Maerker JM. Shear degradation of partially hydrolyzed polyacrylamide solutions. Soc Pet Eng J. 1975;15:311-322.

55. Bird BR, Armstrong RC, Hassager O. Dynamics of Polymeric Liquids, vol. 1. Hoboken, NJ: John Wiley and Sons Ltd; 1987.

56. Huang B, Hu XY, Fu C, Cheng HR, Wang X, Wang L. Molecular morphology and viscoelasticity of ASP solution under the action of a different medium injection tool. Polymers. 2019;11:1299.

How to cite this article: Huang B, Hu X, Fu C, Wang L. Experimental evaluation of ASP flooding to improve oil recovery in heterogeneous reservoirs by layered injection approach. Energy Sci Eng. 2020;8:3148–3164. https://doi.org/10.1002/ese3.735