INTRODUCTION

As the reserves of conventional light oil begin to dwindle, heavy oil is becoming more and more important for meeting the increasing demand for energy. Heavy oil is usually classed as an unconventional oil resource whose viscosity in reservoirs typically ranges from 50 to 50,000 mPa s.\(^1\) The high viscosity of heavy oil causes poor fluidity which is the key issue restricting its development. The high mobility ratio of water to heavy oil leads to only about 5%-10% of the original oil being recovered in the primary water flooding stage\(^2\): the poor sweep efficiency caused by the adverse mobility ratio of water and oil is responsible for such low incremental recovery. To reduce the viscosity of heavy oil, and hence
enhance its fluidity, thermal recovery methods are usually adopted to enhance the heavy oil recovery rate (considering the great sensitivity of oil viscosity to temperature). Thus, methods such as steam huff and puff injection, steam flooding, in situ combustion, and steam-assisted gravity drainage have all been used. These thermal techniques have been successful in certain reservoirs (those with thick pay zones and absence of bottom water). However, they cannot be employed in deep, thin reservoirs due to the severe heat loss during injection. Moreover, consuming a large amount of fuel to generate steam is sometimes not economical or environmentally friendly. Therefore, nonthermal enhanced oil recovery (EOR) methods are required to remove the remaining oil after water flooding.

In recent years, a great deal of research has been undertaken to improve heavy oil recovery using chemical flooding methods, including alkali flooding, alkali-surfactant (AS) flooding, and surfactant-polymer (SP) flooding. Adding alkali is cheap and can significantly contribute to water-oil interfacial tension (IFT) reduction, oil-in-water (O/W), or water-in-oil (W/O) emulsification when recovering heavy oil. However, the resulting high consumption of alkali and severe scaling problems can restrict the application of alkaline chemical systems. Hence, alkali flooding has not yet been used industrially. In this case, chemical systems based on alkalis may become increasingly more important for the EOR of heavy oil, especially in the context of SP systems. In fact, SP systems have been much researched and applied in the recovery of conventional light oil, taking advantage of the well-known ultralow IFT, emulsification, wettability alternation, and water-oil mobility improvement mechanisms, etc. Following on from the research into chemical flooding in light-oil reservoirs, the IFT behavior of heavy oil-chemical systems has been much investigated, and ultralow IFT has also been suggested for heavy oil recovery applications by some researchers (as it is for light oil). Nevertheless, a progressive understanding of the heavy oil recovery mechanism is gradually formed such that the role of the emulsification mechanism should be more emphasized in extending the sweep volume and recovering heavy oil compared to conventional ultralow IFT. It is believed that, as the heavy oil is very vicious, the poor sweep efficiency (caused by the consequent adverse water-oil mobility ratio) is the primary problem needing to be resolved by SP flooding instead of the conventional displacement efficiency (for light oil).

By chance, the emulsion mechanism bestows dual functions in enhancing sweep efficiency. First, it reduces the viscosity of the heavy oil (by forming an O/W emulsion), making it easier to flow from a deep reservoir to the producing wells. Second, it improves the water-oil mobility ratio (by both reducing the viscosity of the heavy oil and plugging the water channels with droplets of emulsified oil), thus, contributing to sweep volume enlargement. These become highly significant when recovering heavy oil. After a systematic investigation of the contemporary situation with respect to heavy oil-chemical flooding, Pei concluded that it is more important to expand the sweep volume than improve the displacement efficiency for heavy oil recovery. This is because of the lower sweep efficiency in the previous water flooding step with heavy oil (compared to light oil). By conducting a series of chemical flooding tests on heavy oil, Zhang and Zhou also recognized that the enhanced recovery of heavy oil is mainly due to the plugging of the water channels and the lowering of the IFT. This is obviously different from light-oil EOR processes where IFT reduction seems to play the dominant role. Furthermore, studies have suggested that O/W or W/O emulsions do indeed plug water-flooded channels, which results in improved volumetric sweeping of reservoirs. McAuliffe found that water flows into less permeable regions, leading to extended sweep volumes when an emulsion enters into the more permeable regions and plug them by the Jamin effect. Yu found that a fine-emulsion system exhibits good plugging and sweep-volume-enlargement behavior. More recently, Ding performed a microscopic and macroscopic modeling study of SP flooding of heavy oil reservoirs and found that a good-emulsification-oriented (GEO) SP system clearly outperformed conventional ultralow IFT systems when recovering heavy oil. This directly verifies the significance of extending the sweep volume using a GEO SP system (instead of a conventional ultralow IFT-oriented system).

If we accept the importance of emulsification in extending sweep volume and recovering heavy oil during SP flooding (according to previous reports), then the detailed emulsification behavior of heavy oil in porous media (instead of common bottles), the oil recovery performance, and their influencing factors naturally become the next concerns before applications are devised. However, these issues are in need of clarification as the dominant role of emulsification (over ultralow IFT) in recovering heavy oil has only just been recently recognized and the existing studies on emulsification behavior have been conducted mostly via bottle tests rather than porous media. Therefore, a GEO SP system (that can form O/W emulsions with excellent stability but have non-ultra-low IFT with heavy oil) was adopted in this paper to displace heavy oil (instead of the conventional ultralow IFT system with relatively bad emulsion stability). A series of heavy oil in situ emulsification and displacing tests in porous media were designed and conducted to study the emulsification behavior, recovery, and their influencing factors. The results obtained in this research are intended to contribute to the optimization and control of such valuable and promising GEO SP flooding agents in the context of heavy oil recovery.
EXPERIMENTAL SECTION

2.1 Fluids and chemicals

The heavy oil used was collected from the Shengli oil field, Dongying, China. The density and viscosity of the oil were measured and found to be 969.2 kg/m³ (70°C, 0.101 MPa) and 657.0 mPa·s (70°C, 0.101 MPa), respectively. The GEO surfactant used is an anionic and nonionic compound variant. The polymer used to prepare the SP system is a partially hydrolyzed polyacrylamide (HPAM) with a molecular weight of $2.0 \times 10^7$. The SP system used consists of 0.1%–1.0% surfactant and 0.18% HPAM.

The measured equilibrium IFTs between the SP systems used (0.1% S, 0.3% S, 0.6% S, and 1.0% + 0.18% P) and heavy oil were all at a non-ultra-low level ($8.9 \times 10^{-1}$ mN/m, $3.0 \times 10^{-1}$ mN/m, $1.8 \times 10^{-1}$ mN/m, and $1.1 \times 10^{-1}$ mN/m). The viscosity of the systems was measured at about 33.5 mPa·s (at a shearing rate of 7.34 s⁻¹). The emulsification behavior of this GEO SP system has been thoroughly investigated via bottle tests (including emulsifying capacity and emulsion stability) in a previous paper, and it indeed exhibits an excellent ability to stabilize heavy oil emulsions. The salinity of the simulated formation water is 9.754 g/L (Table 1).

2.2 Heavy oil emulsification tests in sand packs

Emulsification is the key to extending the sweep volume (via the Jamin effect of the emulsified oil droplets), reducing oil viscosity (by the formation of an O/W emulsion), and finally enhancing heavy oil recovery. In this part, rather than the commonly employed bottle test method, a series of flood tests were designed and carried out using sand packs. During the tests, liquid samples (containing emulsified oil droplets) produced from sand packs were observed microscopically using a digital microscope; then, images of those emulsified oil droplets were obtained, and finally, statistical analysis based on these images was conducted using ImageJ software for particle size measurement. Thus, we were able to judge the morphologies and size distributions of the emulsions present.

The sand packs used for the flood tests had diameters of 2.5 cm, lengths of 10 and 80 cm, and a permeability of ~1300 mD. Figure 1 shows a schematic representation of the layout of the flood test apparatus. After the models were prepared and their permeability measured, they were saturated with oil, aged for 24 hours, and then subjected to primary water flooding (to a high water cut of 98.0%). Three different SP injection schemes were then implemented:

1. A flood test using a long sand pack (80 cm; permeability ~1300 mD) in which three sampling points were distributed along the axial direction. After water flooding, a large volume of the SP system (1.0 pore volume (PV), 0.3% S + 0.18% P) was continuously injected into the model at a rate of 0.25 mL/min. When the injection volume of SP reached 0.3 PV, 0.5 PV, and 1.0 PV, respectively, the liquid samples (one or two drops per sample) were collected from the sampling points and outlet of the model directly onto a slide for online and immediate observation and analysis by a digital microscope and ImageJ software. This experiment allows the emulsification of the heavy oil to be determined and the effect of migration distance on the emulsion could also be deduced.

2. A series of flood tests using short sand packs (10 cm; permeability ~1300 mD) and SP systems with different surfactant contents. Following the previous water flooding step, a limited volume (0.3 PV) of the SP systems was used with 0.1%, 0.3%, 0.6%, and 1.0% surfactant content (injected at a rate of 0.25 mL/min into three separate short sand packs). After the injection of a 0.3 PV SP system, the liquid produced from the outlets of the models was sampled and used for further microscopic observation and particle size analysis. Thus, the effect of varying the surfactant content on the heavy oil emulsification process could be derived.

3. A series of flood tests using a constant SP system (0.3% S + 0.18% P) injected at different rates (0.25, 0.5, 1.0, and 1.5 mL/min, equivalent to seepage velocities of 2.0, 4.0, 8.0, and 12.0 m/d) into three short sand packs (10 cm; permeability ~1300 mD). As before, after the injection of 0.3 PV SP system using varied injection rates, the liquid samples were collected from the outlets of the models for particle size analysis. Then, by comparing the morphologies and size distributions of the emulsions produced in these experiments, the effect of seepage velocity on the heavy oil emulsion could subsequently be determined.

All of the abovementioned experiments were carried out at 70°C which is the reservoir temperature of the Shengli oilfield.

| Ion       | Cl⁻ | SO₄²⁻ | CO₃²⁻ | HCO₃⁻ | Na⁺ + K⁺ | Ca²⁺ | Mg²⁺ | Total |
|-----------|-----|-------|-------|-------|---------|------|------|-------|
| Content (mg/L) | 5423.0 | 0.0 | 0.0 | 656.0 | 3414.0 | 193.0 | 68.0 | 9754.0 |
2.3 | In situ viscosity measurements

The formation of O/W emulsion helps to decrease the viscosity of the heavy oil, enhance its fluidity, improve water-oil mobility, increase sweep efficiency, and, ultimately, increase oil recovery. In order to determine the ability of such a GEO surfactant to improve the mobility of the heavy oil as a result of viscosity reduction, heavy oil and surfactant were simultaneously injected into sand packs (10 cm; permeability $c. 1300 \text{ mD}$) at a total injection rate of 0.5 mL/min (at 70°C). Then, the stable value of the injection pressure was recorded for in situ viscosity calculation of the oil and water mixtures according to Darcy’s law. Furthermore, tests using a variety of surfactant content (0.0%, 0.1%, 0.2%, 0.3%, 0.4%, 0.5%, and 0.6%) and water cut (80%, 70%, 60%, 50%, and 40%) were conducted to investigate the effects of these factors on the reduction in the viscosity of the heavy oil resulting from emulsification.

It is worth pointing out that only the surfactant was employed in these experiments; that is, no polymer was added to these systems. This is because the viscosity of the polymer solution varies with the surfactant content and also decreases during the injection process due to shearing degradation. This will affect the measured equilibrium injection pressure and, therefore, the in situ viscosity calculated for the mixture.

2.4 | Heavy oil recovery tests

The EOR performance of the GEO SP system and the factors affecting it were finally investigated via another series of flood tests using medium-sized sand packs (30 cm; permeability $\sim 1300 \text{ mD}$). A total of three experimental schemes were then implemented involving flood tests employing:

1. Three different chemical systems: 0.3% S, 0.18% P, and 0.3% S + 0.18% P;
2. SP systems with different surfactant contents: 0.1%, 0.3%, 0.6%, and 1.0% (+0.18% P);
3. Different SP slug sizes: 0.1, 0.3, 0.7, and 1.0 PV (for a constant 0.3% S + 0.18% P system).

These experiments thus allow the effect of system type, surfactant content, and slug size on the recovery of heavy oil to be found. The specific experimental procedure used is as follows. First, the wet-packed sand pack was flooded with water to measure its permeability. Then, the temperature of the system was increased to 70°C after which crude oil was pumped into the model to displace the water and allow oil saturation. Thereafter, the model was flooded with water until the amount of oil produced became negligible (water cut $\geq 98\%$). Then, the target chemical solution was injected to displace the remaining oil. This was followed by postwater flooding until the volume of oil gathered in the collector became negligible.

3 | EXPERIMENTAL RESULTS AND DISCUSSION

3.1 | Emulsification behavior of heavy oil in porous media

The emulsification of the heavy oil is the key to reducing the oil’s viscosity and the plugging of the water channels by the emulsified oil droplets which, in turn, enlarges the sweep volume. The behavior of heavy oil (with respect to emulsification capacity, emulsion stability, and emulsion size distribution, etc) has been extensively studied using conventional bottle tests. However, its behavior in porous media is different from that in the bottle tests due to the different emulsion-generation mechanisms involved. To be more specific, the shearing action acting on the water-oil interface and snap-off effect occurring at the throats of the pores are thought to be the main mechanisms responsible for emulsion formation in porous media. In contrast, emulsification in bottle tests mainly occurs because of the simple shaking or stirring action employed and the subsequent mixing of the water and oil. As a result, chemical additives behave differently in bottles and porous media. For example, it has been found that an ultralow IFT SP system can give excellent emulsification results using heavy oil in bottle tests, but produce virtually no emulsion in porous media (where it was more inclined to remove oil in the form of “oil wires” instead of an emulsion).
Naturally, different emulsification mechanisms may also lead to different factors affecting the emulsification performance. Therefore, in order to more accurately judge the emulsification behavior of the heavy oil in porous media, attention was paid to the morphologies of the heavy oil emulsions in the sand packs and their size distributions. In addition, the effects of migration, surfactant content, and seepage velocity were also considered.

3.1.1 Effect of migration in porous media

A flood test was first carried out in a long sand pack with three sampling points distributed along its length. The liquid samples collected from these points and the outlet of the model were observed microscopically at different SP injection volumes of 0.3, 0.5, and 1.0 PV (Figure 2).

Figure 2 illustrates that by the time 0.3 PV SP had been injected into the sand pack, some of the heavy oil emulsion had started to appear in the front part of the model (0‐50 cm region). At this stage, the chemicals had not reached the back of the model (50‐80 cm) which is still in the pure water flooding state so there is almost no emulsion present. Comparing the images obtained from these two parts of the model, it is apparent that pure water alone is hardly able to emulsify the heavy oil at all (at the end of that flooding stage), but the SP system employed is indeed able to do so.

As the injection of the SP continued, the number of emulsion particles observed clearly became larger. After the whole 1.0 PV of the SP had been injected, the emulsified oil in the 0‐30 cm part had migrated to the rear parts of the model so almost no emulsion was found in this part. In the 30‐80 cm part, many well‐formed heavy oil emulsions were clearly present. This indicates that more and more emulsions were formed with increased migration distance (by the increasing amount of snap‐off time occurring with the pores). Coalescence of the emulsion and resulting decrease in number of emulsion particles, as claimed in some existing results,35,36 did not appear to happen.

Figure 2 also reveals that the emulsion particles got smaller as the migration distance increased. The distributions of their sizes also became more uniform (Figure 3). For example, the emulsion collected from the 50 cm sampling point contained particles with a relatively large median size (D50) and corresponding to 54.7 μm. As it mitigated further to the 70 and 80 cm points, the corresponding D50 values decreased to 43.0 and 39.0 μm, respectively. This also implies that the plugging capacity of the emulsion may be reduced as the migration distance increases (as the larger the particles in the emulsion, the more powerful the ability of the emulsion to plug the water channels.34,37 Fortunately, the decrease in the size of the emulsion particles gradually slows down as the migration distance increases. For instance, the median
size decreases by 11.7 μm as the emulsion moves from the 50 to 70 cm point (from 54.7 to 43.0 μm)—the corresponding decrease as it moves from 70 to 80 cm is only 4.0 μm. Additionally, from the emulsion-size-distribution curves in Figure 3, it can be seen that, with increased migration, such curves become narrower and higher, indicating the increasingly concentrated and more uniform size distribution of emulsions. The size and size-distribution variation observed as the heavy oil emulsion migrated through the sand pack indicates it has the ability to undergo “self-adjustment” to match with, and plug, the pores in the porous media.

The appearance of a large number of emulsified oil droplets in the sand packs (as shown in Figure 2) shows that the heavy oil was readily emulsified even with a limited migration of the SP system (ie, a range of 0-80 cm). In other words, once this GEO SP system is injected into a reservoir, it will work efficiently in emulsifying heavy oil even in the near-wellbore regions. Then, those well-formed emulsions will migrate to the depths of the reservoir, evolve into smaller but more numerous oil droplets with better uniformity, trigger and help the generation of new emulsion particles, simultaneously, plug the existing water channels, and contribute to oil recovery.

3.1.2 Effect of surfactant content

The size of the emulsion particles is the key to plugging the water-flooded channels. As observed above, as the emulsion migrates it self-adjusts to fit the pore structure. However, apart from migration distance, there are other factors that may affect the size of the particles in the heavy oil emulsion including surfactant content and seepage velocity. These factors will, therefore, also affect the plugging capacity of the emulsion and need to be investigated.

Figure 4 illustrates the microscopic morphologies and size distributions of emulsions produced using different amounts of surfactant (0.1%, 0.3%, 0.6%, and 1.0%). It is apparent that no obvious signs of an emulsion appear in the sample collected when the surfactant content is 0.1%. It seems that too low a surfactant content cannot endow the SP system with the emulsifying ability to handle the heavy oil. As the surfactant content is increased to 0.3%, more of it is available for adsorption at the oil-water interface to form and stabilize emulsion particles. Therefore, a large number of large emulsified oil droplets appear at this concentration resulting in a D50 value of 62.0 μm. To determine whether even higher surfactant contents facilitate a better level of heavy oil emulsification, surfactant contents of 0.6% and 1.0% were also used. According to Figure 4, the increased surfactant content increases the uniformity of the distribution of the particle sizes in the emulsion and reduces the median size of the oil droplets present (giving smaller D50 values of 45.5 μm and 42.0 μm at surfactant contents of 0.6% and 1.0%). Considering the fact that larger emulsion particles result in a more powerful plugging effect in the water channels, increasing the surfactant content from 0.3% to 1.0% may be detrimental to the SP system’s plugging capacity. Therefore, too high a surfactant content may be unfavorable and hence undesirable in this respect.

3.1.3 Effect of seepage velocity

Different injection rates (0.25, 0.5, 1.0, and 1.5 mL/min) were used to produce different seepage velocities (2.0, 4.0, 8.0, and 12.0 m/d) in the sand packs. The morphologies and distributions of the particles produced in the resulting emulsions were then determined (Figure 5). As the velocity increases, the oil droplets in the emulsions clearly tend to decrease in size. At first, the decrease is quite rapid (D50 falls from 62.0
to 46.3 μm as the velocity increases from 2.0 to 4.0 m/d). It then decreases more slowly, showing signs of stabilizing at higher injection rates (D50 falls to 45.7 and 38.6 μm when the seepage velocities are 8.0-12.0 m/d). At the same time, the oil droplets also become more uniform in size (the distribution curve becomes narrower).

It may be that larger flow rates lead to stronger shearing and tensile effects being experienced by the oil droplets via the pore throats, and this enhanced breaking effect leads to smaller particles forming in the emulsion: Whatever the explanation, this phenomenon needs to be kept in mind. High injection rates can accelerate oil production and thus help produce more oil in a certain amount of time (making production more economical). However, the resulting high seepage velocity will reduce the sizes of the emulsified oil droplets produced and potentially weaken their ability to plug the pores in the reservoir. Li also reported a phenomenon whereby the plugging capacity of the emulsion decreased with increased seepage velocity.38

### 3.2 Reduction in the viscosity of heavy oil due to emulsification

Reducing the viscosity of heavy oil (by forming an O/W emulsion) and hence enhancing its fluidity is one of the main mechanisms by which such GEO SP system function.39 The reduction in viscosity achieved is closely related to the emulsification behavior of the heavy oil in porous media and is also influenced by many other factors (eg, surfactant content). In this section, different surfactant solutions were injected into sand packs, the equilibrium injection pressures were measured, and in situ viscosities were calculated according to Darcy’s law. At the same time, various oil/water ratios were used (2:8, 3:7, 4:6, 5:5, and 6:4) as realized by separately controlling the same injection rate of oil and water, to simulate, on the one hand, different timings of water cut in water-flooded reservoirs (80%, 70%, 60%, 50%, and 40%, respectively). On the other hand, these measures also can reflect the flooding processes in zones with different water cuts in real reservoirs because the development stages of different water cuts (or oil/water ratio) will be experienced in the process of real reservoir development, and the water cuts (or oil/water ratio) during water flooding at different positions of a reservoir may also be different due to the varied concentration of the remaining oil.

Figure 6 shows plots of the dynamic injection pressures measured as a function of the injection volume for two cases (water cuts of 80% and 40%). The pressure drop across a sand pack increases at first as the oil and water are simultaneously injected. Then, it tends to stabilize as a steady state is approached. The pressure drops measured when the water cut

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**Figure 5** Morphologies and size distributions of emulsion particles produced using different seepage velocities (2.0, 4.0, 8.0, and 12.0 m/d). The SP system used in each case consisted of 0.3% S + 0.18% P

**Figure 6** The pressure drops measured during the coinjection of oil and water for different water cuts and surfactant contents.
is lower (e.g., 40%) are clearly greater than those when the water cut is higher (e.g., 80%). This indicates that reducing the viscosity of heavy oil (via, e.g., emulsification) is more necessary in low water cut development stages of a reservoir (or in low water cut areas of a reservoir). The steady state pressure-drop values obtained at the end of oil-water injection processes shown in Figure 6 can be used to calculate the in situ viscosities of the oil-water mixtures. The corresponding viscosity-reduction rates can then be calculated as well, as shown in Figure 7.

Figure 7 demonstrates that the in situ viscosities of the oil-water mixtures decrease rapidly at first as the surfactant content is increased. Then, the decrease in viscosity slows down and gradually stabilizes. The addition of this GEO surfactant is therefore clearly able to reduce the viscosity of the heavy oil-water mixtures employed. The reduction in the size of the particles in the O/W emulsion and increase in uniformity of their size distributions achieved by increasing the surfactant content (as shown in Figure 4), therefore, contribute to reducing the viscosity of the heavy oil. The 80% water cut data were taken as an example. The in situ viscosities are 81.2, 46.9, 18.3, 12.7, 11.1, and 9.5 mPa s when the surfactant contents are 0.0%, 0.1%, 0.2%, 0.3%, 0.4%, and 0.6%, respectively. The corresponding viscosity-reduction rates are 0.0%, 42.1%, 77.4%, 84.3%, 86.3%, and 88.2%, respectively. Therefore, the optimal surfactant content to reduce the viscosity of the oil seems to be about 0.2%. Above this optimal value, even though the emulsified oil droplets do become smaller and more uniform in size (see Figure 4), the benefits gained do not allow further significant reduction in oil viscosity (as shown in Figure 7).

In other words, although we can reduce the viscosity of the heavy oil by increasing surfactant content (because of the reduced size and increased uniformity of the emulsion), beyond the optimal surfactant concentration the additional changes in the properties of the emulsion are less efficient in further reducing the viscosity of the oil.

In addition, comparing the in situ viscosities calculated under different water cut conditions, it can also be seen that the lower the water cut, the greater the optimal surfactant content required to reduce the viscosity of the heavy oil, and the worse the viscosity-reduction effect even with such optimal content.

### 3.3 Heavy oil recovery

#### 3.3.1 Relative performance of S, P, and SP systems

To investigate the details of the roles played by the surfactant and polymer components in displacing heavy oil, flood tests were carried out using three different chemical systems: 0.3% S, 0.18% P, and 0.3% S + 0.18% P. To help eliminate measurement errors, longer sand packs (30 cm; permeability 1300 mD) were used for these experiments with larger pore volumes and saturated oil volumes. The measured oil recovery factors and pressure drops recorded during S, P, and SP flooding are presented in Figures 8 and 9.

Although the surfactant on its own has a significant viscosity-reduction capacity according to the simultaneous injection results shown in Figure 7, it is very disappointing to see that it yields a very poor 2.1% increase in oil recovery factor (Figure 8). This reflects a fact that it is difficult for the surfactant on its own to remove and emulsify the initially nonflowing heavy oil after water flooding. Only when the oil is already flowing with the surfactant solution (as in our

**FIGURE 7** The in situ viscosities of the oil-water mixtures and corresponding viscosity-reduction rates plotted as a function of the surfactant concentration.
simultaneous oil and water injection experiments) can the surfactant solution effectively emulsify the heavy oil due to the flow-induced mixing effect between the oil and surfactant solution. In other words, before attempting to use surfactant solution to emulsify heavy oil in porous media, we first need to make them flow and mix together. Then, emulsification can occur through the snap-off effect caused by the pores. Actually, the limited pressure increase associated with 0.3% S injection (shown in Figure 9) also suggests that poor activation and emulsification of the heavy oil occur. This is because such behavior would result in a high resistance to flow and hence pressure drop.

Figure 8 illustrates that a much better 9.2% increase in recovery factor was obtained when 0.18% P was injected (compared to that achieved using S-only flooding). Clearly, therefore, the polymer outperforms the surfactant when used on its own to recover heavy oil. This again confirms that the improvement in water-oil mobility and subsequent enlargement in sweep volume (by the viscous polymer solution) is very important when it comes to activating and removing heavy oil. The high injection pressure realized during P flooding (Figure 9) also illustrates the greater ability of the polymer to extend sweep efficiency and remove heavy oil.

Finally, when the surfactant and polymer were used together in the form of an SP system (0.3% S + 0.18% P), the highest incremental recovery factor of 15.6% was obtained. The excellent performance of the SP system can be explained in terms of oil displacement characteristics of the surfactant and polymer described above. When the SP system is first injected, the polymer component starts to improve the mobility of the initially static oil and enlarges the sweep volume. The flowing oil then gradually mixes with the SP system and the surfactant component begins to emulsify the heavy oil. Once emulsified oil droplets are formed, they will, in turn, help the polymer component to extend the sweep volume by plugging the water channels (via the Jamin effect). As a result, the oil flow will improve further, which will generate more emulsions. In addition to their contribution to plugging, the emulsion formed also helps to reduce the viscosity of the heavy oil which makes it more mobile (see Figure 7). This may be the main reason for the lower flooding pressure observed in the SP system compared to that associated with the single polymer shown in Figure 9. Ultimately, it is the synergism between the polymer and surfactant that makes the SP system the most potent system for recovering heavy oil. Put briefly, without the assistance of the polymer to extend the sweep volume, the GEO surfactant flooding is very poor and should not be applied on its own to recover heavy oil; therefore, such a surfactant should be jointly used with a polymer, letting the oil first polymerize, then, when emulsified by the surfactant, this, in turn, reduces its viscosity and extending sweep volume by emulsification.

### 3.3.2 | Effect of surfactant content on SP flooding

Surfactant–polymer systems with higher concentrations of surfactant will make a greater contribution to the emulsification of the heavy oil. The particles in the emulsion will be smaller and more uniformly distributed in size (Figure 4), and this helps to reduce the viscosity of the heavy oil (Figure 7). However, oil droplets that are too small may not be desirable when it comes to plugging the water-flooded channels. Therefore, we need to determine whether it is worthwhile increasing the surfactant content of an SP system (or not) from the point of view of the contribution such an action will make to the recovery of heavy oil. To this end, the oil recovery factors measured as a result of SP flooding using systems with different surfactant contents (0.1%, 0.3%, 0.6%, and 1.0%) are shown in Figure 10.
The SP system with the lowest surfactant content (0.1%) is hardly able to emulsify the heavy oil (see Figure 4) as there is not enough surfactant adsorbed onto the oil-water interface to stabilize the emulsion. The high injection pressure shown in Figure 11 also suggests that this SP system provides the worst performance in terms of reducing the viscosity of the heavy oil via emulsification. As a result, it produces the lowest incremental oil recovery rate obtained (10.5%).

Increasing the S content to 0.3% allows the heavy oil to be well emulsified in the porous media (Figure 4). Together with the effect of the polymer on viscosity, this SP system (0.3% S + 0.18% P) therefore has a good ability to remove heavy oil (recovery is increased by 15.6%). It also causes the injection pressure being a little lower than that of the 0.1% S + 0.18% P system, which indicates it has a strong emulsifying capacity and results in a good reduction in the viscosity of the heavy oil.

Further increasing the surfactant content of the SP system to 0.6% and 1.0% results in the incremental oil recovery factors decreasing to 11.0% and 12.0%, respectively: According to the viscosity curves shown in Figure 7, a surfactant content of 0.6% should reduce the viscosity of the oil very well as a result of O/W emulsification. The low injection pressure of the corresponding SP system (Figure 11) also suggests this is the case. However, the emulsion formed will consist of particles that are smaller (as observed in Figure 4) and this will subsequently weaken the capacity of the emulsion to plug the water-flooded channels which makes the SP flooding process less effective. Thus, too high a surfactant content is not desirable for such GEO SP systems when recovering heavy oil.

### 3.3.3 Effect of slug size on SP flooding

The effect of slug size on oil recovery is one of the main concerns in chemical flooding. As a result, many related studies have been carried out, especially in relation to the EOR of light oil using chemical systems. Typically, a slug size of about 0.3-0.6 PV is usually recommended for recovering light oil, or heavy oil of relatively low viscosity. However, the optimum slug size required with GEO SP systems used to remove “ordinary” heavy oil (ie, of relatively high viscosity like the 657.0 mPa s samples used in this research) is still not clear. In this section, SP slugs of different sizes (0.1, 0.3, 0.7, and 1.0 PV) were injected into sand packs to displace the heavy oil after water flooding. Figure 12 shows the oil recovery factors thus determined.

Figure 12 shows that the incremental recovery factor increases significantly as the slug size is increased (slug sizes of 0.1, 0.3, 0.7, and 1.0 PV yielding incremental recovery factors of 6.9%, 15.6%, 25.7%, and 29.7%, respectively). The incremental recovery factor clearly does not increase linearly with slug size. Instead, the rate at which it increases slows down with increasing slug size, but the increase in recovery factor is still considerable when the size is enlarged from 0.7 to 1.0 PV. Therefore, a large slug size approaching 1.0 PV may be the optimal dosage to employ when carrying out SP flooding using this GEO system. This is very different to the optimal size recommended for light-oil flooding processes, that is, 0.3-0.6 PV (beyond which further increases in incremental recovery factor).

The high viscosity and poor fluidity of heavy oil may be responsible for significantly different optimal slug sizes being required during chemical flooding. More specifically, heavy oil is just too viscous to flow after water flooding, so pure water is hardly able to build up a high enough flow resistance (and pressure in the water-flooded channels) to force the subsequent water flow to reach the regions initially saturated by the heavy oil, and hence to remove it. When
the SP system is injected, it is able to establish high resistance in such channels due to its higher viscosity compared to pure water. Thus, the displacing agents that follow will migrate to unswept regions and displace the remaining oil there. In fact, this is one of the main mechanisms by which SP flooding has been recognized to act during conventional light-oil flooding.

Unfortunately, high polymer concentrations are often not allowed during heavy oil SP flooding because of limitations imposed by injectivity and economy. As a result, the viscosities of SP systems are far lower than that of heavy oil (in this research, the viscosities of the SP system and heavy oil are about 33.5 and 657.0 mPa s, respectively, so the water-oil mobility ratio is close to 20). Therefore, the ability of the SP to increase flow resistance in the water-flooded channels is relatively limited so that the enlargement of the sweep volume is also limited. Because of this, increasing the SP slug size to establish larger resistance in the water channels becomes significantly important for extending the sweep volume and recovering heavy oil. Increases in injection pressure as larger slugs are used are clearly observed in Figure 13, indicating that higher flow resistance is built up using larger SP slug sizes. As a result, the incremental recovery factor grows significantly with increased slug size, as shown in Figure 12, but for light-oil flood processes, it is significantly less viscous, so a much lower resistance is needed in the water-flooded channels to make the subsequent displacing agents migrate to the unswept regions (and hence remove the light oil located there). Therefore, the flow resistance established by an SP system with a relatively modest viscosity (a few dozen mPas) can meet such requirements (as the SP and light oil have similar viscosities). As a result, a large slug of SP is not needed to build up high flow resistance in the water-flooded channels when recovering light oil.

4 | CONCLUSIONS

1. Heavy oil could indeed be emulsified in situ by the GEO SP system in porous media. The resulting O/W emulsion undergoes “self-adjustment” when migrating in porous media, evolving into a smaller emulsion with better uniformity to match with, and plug, the pores. Increasing the surfactant content and seepage velocity also results in smaller and more uniform emulsions.

2. Such oil-in-water in situ emulsification indeed helps to reduce heavy oil viscosity in porous media: There is an optimal surfactant content for such viscosity reduction and the lower the water cut, the greater the optimal surfactant content, and the poorer the viscosity-reduction effect.

3. On its own, the GEO surfactant performs poorly in recovering heavy oil and is even worse than the polymer on its own; therefore, such a surfactant should be jointly used with a polymer.

4. For such GEO SP flooding, too high a surfactant content may impair heavy oil recovery, while a large slug size contributes significantly to the recovery.

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