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# Foam Systems for Enhancing Heavy Oil Recovery by Double Improving Mobility Ratio

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**Abstract:** The recovery of heavy oil is challenging due to its high viscosity. Especially in water flooding, the high viscosity of heavy oil induces a high water/oil mobility ratio, resulting in frequent channeling and fingering. In the present work, the viscosity reduction in heavy oil caused by foaming agents is studied. Among the studied foam systems, the KX-048 foaming agent had the best oil viscosity reduction performance. It also shows excellent foaming performance, including large foam volume, long foam half-life, and high foam comprehensive index. With the reduction in oil viscosity, the KX-048 foaming agent decreases the foam/oil mobility to 0.28, which is beneficial for controlling gas channeling and fingering in foam flooding. Moreover, Foam flooding experiments in heterogeneous sand-pack models indicate that KX-048 has excellent efficiency in improving oil recovery, especially in the low-permeable tube. The chosen KX-048 foaming agent could provide a promising pathway for improving heavy oil recovery.

**Keywords:** foam; heavy oil; viscosity; mobility ratio; EOR

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## 1. Introduction

Heavy oil (API gravity < 22, viscosity > 100 mPa·s) [1] has received more and more attention in recent years as the fast growth of oil consumption has made conventional oil not be able to meet the production need [2–4]. Heavy oil accounts for about 70% of total oil reserves [5]. However, the intermolecular stacking and hydrogen bonds among heavy oil molecules result in high viscosity [6,7], which makes the mobility ratio of water to oil too high during waterflooding. As a result, water channeling often happens during the waterflooding of heavy oil, making the sweep efficiency very low. Moreover, the high viscosity also makes it difficult for the water phase to remove oil from the rock channel surface in the formation. These shortcomings make the exploitation of heavy oil seriously restricted. Therefore, varieties of methods [8,9], including in situ combustion [10–12], cyclic steam stimulation [13,14], steam flooding [15–18], steam-assisted gravity drainage (SAGD) [19–21], in situ aquathermolysis [22–25], etc., have been developed to reduce heavy oil viscosity to enhance the recovery. These methods employ increasing formation temperature to reduce the viscosity, which consumes much energy and has a high requirement on equipment. Differently, oil viscosity reduction methods based on the addition of light oil and/or viscosity reducers are usually carried out under milder conditions [26–31]. For example, recent studies also proved that the inhibition of asphaltene precipitation is also an important method for improving heavy oil recovery [32]. Moreover, surfactants are often injected into heavy oil to form emulsions or foams to improve mobility [26,33–35].

Emulsions are generally realized by adding surfactants, which could decrease the interface tension between the water phase and oil phase into heavy oil. The mobility of emulsions is much better than that of the original heavy oil. In comparison, foam systems are formed by adding surfactants, which could facilitate the dispersion of the gas phase in the water phase [36,37]. The formation of foam could significantly improve the mobility ratio of water to oil, decrease the probability of water channeling, and increase the swept area. Moreover, the formed foam could also further decrease oil viscosity, enhancing the oil recovery further. Therefore, the employment of foam systems could be very promising for enhancing heavy oil recovery. However, one of the main challenges in applying foam systems in heavy oil recovery is to find suitable foam systems. In the present work, several foam systems with the potential to improve heavy oil recovery were investigated. The results showed that the KX-048 foam agent from Shandong Kexing Chemical Co., Ltd. (Dongying, China) showed the most impressive efficacy in foam performance, oil viscosity reduction, and improving oil recovery.

## 2. Experimental Section

### 2.1. Chemicals and Reagents

The crude oil was from Tuha Oilfield Company (Hami, China). Foam agents XHY-4, XHY-4J, XHY-4Q5, and XHY-4Q7 were from Xinghua Chemical Co., Ltd. (Chengdu, China). Foam agents SDFL-2066, SDFL-2077, SDFL-2099, KX-048, and KX-CY-56 were from Kexing Chemical Co., Ltd. (Dongying, China). All the chemicals were used as received without further purification.

### 2.2. Preparation of Synthetic Brine

The synthetic brine used in the present work was prepared according to Table 1.

**Table 1.** Composition and recipe of the synthetic brine.

| $Na^+ + K^+$ ($mg \cdot L^{-1}$) | $Ca^{2+}$ ($mg \cdot L^{-1}$) | $Mg^{2+}$ ($mg \cdot L^{-1}$) | $Cl^-$ ($mg \cdot L^{-1}$) | $SO_4^{2-}$ ($mg \cdot L^{-1}$) | $HCO_3^-$ ($mg \cdot L^{-1}$) | Total Dissolved Salts ($mg \cdot L^{-1}$) |
|---|---|---|---|---|---|---|
| 53,090 | 7416 | 1204 | 97,400 | 1224 | 265 | 160,599 |

### 2.3. Foam Performance Evaluation

Foam solutions in synthetic brine were prepared with the surfactant concentration of 0.01%, 0.02%, 0.04%, 0.06%, 0.08%, 0.10%, 0.15%, and 0.20%. Under the conditions of 78 °C and 10 MPa, 100 mL foam solution was injected into an HTHP foam evaluation setup (PMQ-2, Jiangsu Hai'an Petroleum Technology Instrument Co., Ltd., Hai'an, China). The solution was stirred at 9000 rpm for 60 s. The foam volume and foam half-life were measured immediately after the stirring stopped.

### 2.4. Flooding Experiments

The mobility ratio experiments were carried out in sand-pack models (Figure 1). The parameters of the sand-pack models are detailed in Table 2. During the experiments, the sand-pack models were firstly saturated with synthetic brine, and the mobility of the water phase was measured. After that, the sand-pack model was saturated with heavy crude oil, and the oil mobility was measured. After that, foam flooding was carried out, and foam mobility was measured. Based on the mobilities of each phase, the water/oil mobility ratio and foam/oil mobility ratio were calculated.

The mobility ratio experiments were carried out in double-tube sand-pack models (Figure 2). The parameters of the sand-pack models are detailed in Table 3. During the experiments, the sand-pack tubes were sequentially saturated with synthetic brine and crude heavy oil. Then, the parallel tubes were flooded with water until the water content in the harvested liquid reached 98%. Then, foam systems were injected with a 0.3 PV plug. Then, water was injected again until the water content in the harvested liquid reached 98%

again. The pressure, fractional flow, water content, and oil recovery in the two tubes were recorded in the process.

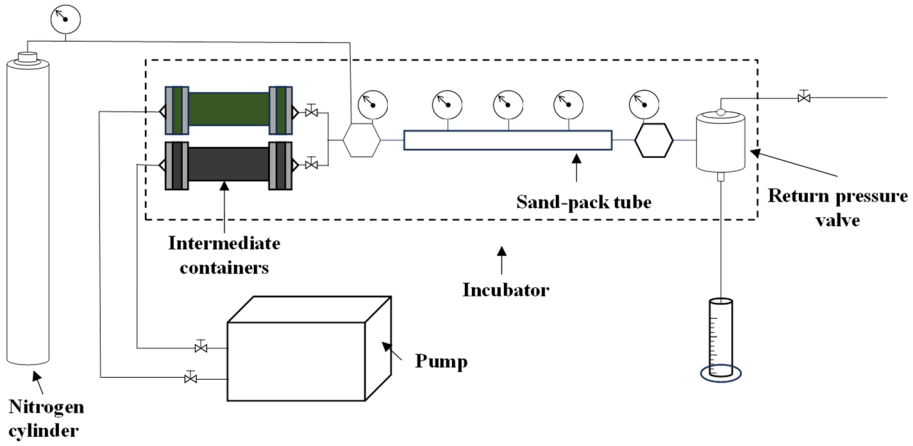



**Figure 1.** The schematic illustration of mobility ratio measurement setup.

**Table 2.** Parameters of sand-pack models.

| Sand-Pack Model | Porosity (%) | Permeability ($10^{-3}$ μm$^2$) | Oil Saturation (%) | Foaming Agent |
|---|---|---|---|---|
| 1 | 36.28 | 229.7 | 86.44 | XHY-4 |
| 2 | 35.70 | 215.6 | 83.35 | KX-048 |
| 3 | 34.36 | 203.4 | 82.42 | - |

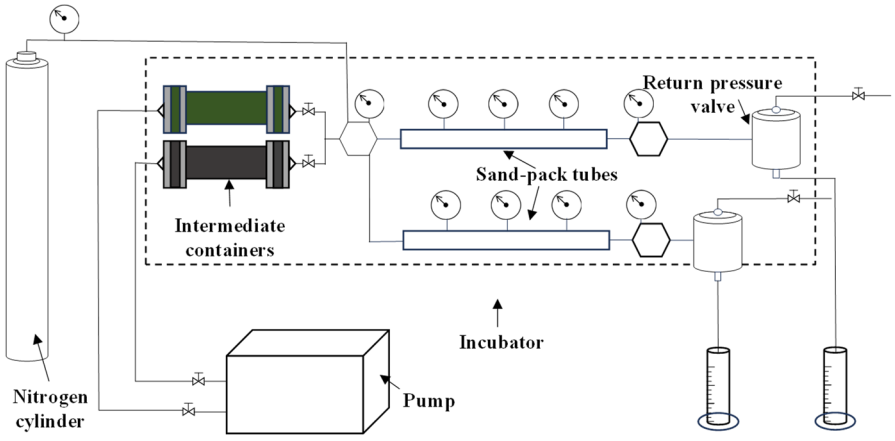



**Figure 2.** The schematical illustration of foam flooding in heterogeneous sand-pack models.

**Table 3.** Parameters of heterogeneous sand-pack models.

| Sand-Pack Model | Tube Permeability | Tube Volume (mL) | Pore Volume (mL) | Porosity (%) | Permeability ($10^{-3}$ μm$^2$) | Oil Saturation | Foaming Agent |
|---|---|---|---|---|---|---|---|
| 1 | Low | 501 | 176 | 35.15 | 87.1 | 81.25 | KX-048 |
| | High | 500 | 180 | 36.74 | 484.8 | 87.78 | |
| 2 | Low | 501 | 164 | 32.75 | 82.4 | 76.22 | XHY-4 |
| | High | 500 | 176 | 35.93 | 540.2 | 80.68 | |

## 3. Results and Discussion

### *3.1. Viscosity Reduction Effect of Foam Systems*

Different from conventional oil, the content of light components in heavy oil is much lower, and the content of resins and asphaltenes is much higher. Further, there are many

polar groups in the molecules of heavy oil, such as carboxylic groups, hydroxyl groups, and amino groups. The interactions among these polar groups make the molecules of resins and asphaltenes stack together, which retards the movement of oil molecules, resulting in higher viscosity. Therefore, the key to reducing the viscosity of heavy oil is to break the intermolecular interaction caused by polar groups to destroy the stacking structures of heavy components. Suitable surfactants could penetrate into the space among the molecules of heavy components, breaking the intermolecular interactions to reduce the viscosity of oil.

As shown in Figure 3, under conditions with higher pressure and/or higher temperature, the heavy oil showed lower viscosity. This trend was consistent with the results reported previously [2,13]. When the pressure was lower than 10 MPa, the decrease in viscosity caused by the temperature increase became much more significant.

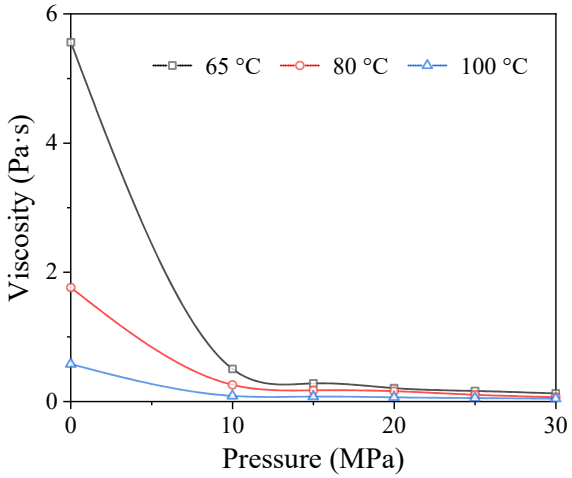



**Figure 3.** Viscosity of heavy oil at different pressures and different temperatures.

As most heavy oil reservoirs have high salinity, common chemical flooding agents, such as partially hydrolyzed polyacrylamide and hydrophobic associated polymers, do not work well, as the molecular chains could shrink under high salinity conditions, which makes the viscosity of the flooding system decreased. Therefore, to improve flooding efficiency, the concentration of flooding agents should be increased. This is not friendly for cost control. Moreover, when the reservoir temperature is higher than 70 °C, the stability of the polymer could be compromised, decreasing the migration distance and duration of flooding systems. As a result, the effectiveness of chemical flooding based on polymer agents is greatly reduced.

Differently, foam systems could maintain stability under high temperature and/or high salinity conditions [38,39]. They could selectively block off water layers and high permeability layers to promote the exploitation of low permeability layers, enhancing the general oil recovery.

The formation of foam in heavy oil could effectively reduce the viscosity. A key factor that significantly affects the decrease in viscosity is the concentration of surfactants. Figure 4 shows the effects of surfactant concentrations on the viscosity of heavy oil with foam systems generated from different foaming agents. All the studied foam systems showed viscosity reduction while forming foam with heavy oil in the studied concentrations. Moreover, the higher the concentration of foaming agents, the more the reduction in oil viscosity. Under conditions with lower foaming agent concentration, surfactants could not sufficiently dismantle the stacking structure of heavy components; therefore, the viscosity reduction was lower. Nevertheless, it should be noted that the foaming agent named KX-048 showed the best performance. When the concentration was 0.1 wt%, the viscosity reduction was 93.71% compared with the original heavy oil.

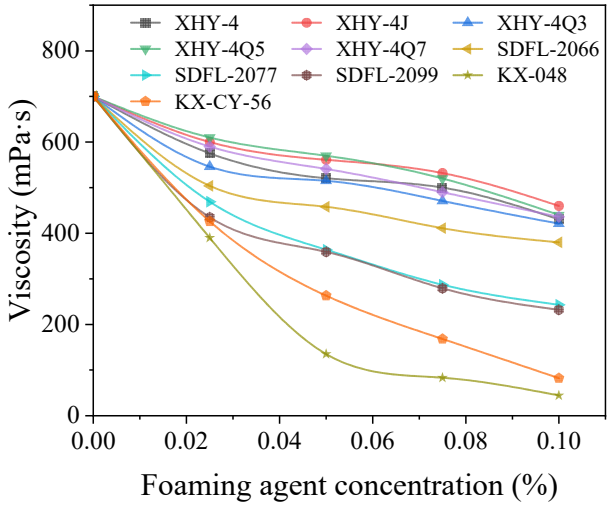



**Figure 4.** Heavy oil viscosity with different foam systems at different concentrations.

### *3.2. The Foam Performance of KX-048 Foam Systems*

KX-048 foaming system showed the best performance for heavy oil viscosity reduction. As mentioned above, the mechanism behind the viscosity reduction in heavy oil caused by foam was the intermolecular interaction between the polar groups of heavy components and foaming agents, which destroyed the stacking structures of heavy components. The surfactants in foam systems penetrated into the space among the molecules of heavy components, breaking the intermolecular interactions to reduce the viscosity of the oil. KX-048 showed the best viscosity reduction performance. It means that it had the strongest interactions with the heavy components in heavy oil.

To identify the optimum parameters for the KX-048 foaming system, investigations on the viscosity reduction in heavy oil under conditions of different KX-048 concentrations, different temperatures, and different interaction times were carried out. As shown in Figure 5a, the concentration of KX-048 was an important factor affecting the viscosity reduction in heavy oil. Without KX-048, the original heavy oil showed a viscosity of 700 mPa·s. After mixing with KX-048 foaming agents with different concentrations, the viscosity of heavy oil decreased. Moreover, when the concentration of KX-048 foaming agent increased from 0.025% to 0.100%, the viscosity reduction became greater, while the further increase in KX-048 concentration induced inferior viscosity reduction. Temperature affected the viscosity of heavy oil as well as the viscosity reduction efficiency of the KX-048 foaming agent (Figure 5b). When the temperature increased from 20 to 90 °C, the viscosity reduction efficiency of KX-048 increased first and decreased in the end, with the highest values achieving over 70 °C. The interactions between the KX-048 foaming agent and the heavy components in oil took time. When foaming agent solutions and heavy oil were mixed, the viscosity of heavy oil started to decrease, and it took 4 h to reach the optimum results (Figure 5c). It means that at least 4 h was needed when the KX-048 foaming system was applied to improve heavy oil recovery. These results indicated that the optimum parameters for KX-048 foaming agent to reduce heavy oil viscosity could be summarized as concentration of 0.1%, temperature over 70 °C, and interaction time over 4 h.

As KX-048 showed the best efficiency on heavy oil viscosity reduction, the foam performance of KX-048 was detailedly investigated. Additionally, another foaming system based on XHY-4 was also studied for comparison.

Foamability and foam stability are the main factors for the evaluation of foam performance. Foamability is used to measure the capacity of a foaming agent to produce foam with liquid. It is usually reflected by the volume of foam generated under a certain condition. The formed foam is a thermodynamically unstable system that could not last forever. The bubbles in the foam could burst due to the decrease in surface free energy. Foam stability, which is usually reflected by the foam half-life and drainage half-life, is used

to quantitatively describe the stability of a foam after generation. The foam comprehensive index is a parameter that takes both foamability and foam stability into account. It reflects the general performance of a foam system. Foam comprehensive index could be calculated according to the following Equation:

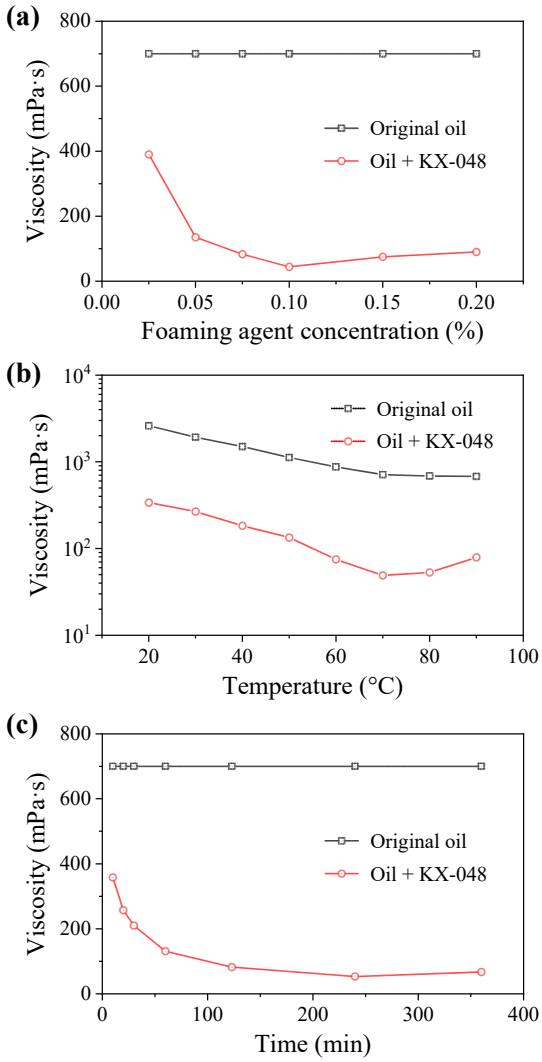



**Figure 5.** The viscosity of the original heavy oil and heavy oil with KX-048 foaming agent at different foaming agent concentrations (**a**), different temperatures (**b**), and different foaming times (**c**).

$$FCI = \int_0^{t_{1/2}} V_f dt = \frac{3}{4} V_f \cdot t_{1/2} \quad (1)$$

where $FCI$ was foam comprehensive index in mL·s; $V_f$ was foam volume in mL; and $t_{1/2}$ was foam half-life in s.

Figure 6a shows the foam volumes of the two foam systems generated with KX-048 and XHY-4 foaming agents at different concentrations. The general trend demonstrates that the foam volume increased with the increase in foaming agent concentration. However, the foam volume of KX-048-generated foam was larger than that of XHY-4-generated foam at the same concentration. When the foaming agent concentration was 0.01%, the foam volume of KX-048-generated foam was 190 mL, while for XHY-4-generated foam, it was 155 mL, a little lower. When the foaming agent concentration increased from 0.01% to 0.15%, the foam volume of KX-048-generated foam increased from 190 mL to 504 mL, increasing by 265 mL. The foam volume was always larger than XHY-4 foam systems. When the concentration of the foaming agent kept increasing from 0.15%, the foam volumes of both the two foam systems no longer increased significantly. Figure 6b shows the foam half-life

of foam systems generated with KX-048 or XHY-4. Foam half-life describes the time for the foam volume to reduce to half of the initial value, which reflects the stability of a generated foam. As shown in Figure 6b, when the concentration of the foaming agent increased from 0 to 0.20%, the foam half-life increased first and reached maxima at 0.15%. After that, the foam half-life decreased. The trend was the same for both cases. However, the foam half-life of foam systems generated with KX-048 was always longer than that of foam systems generated with XHY-4 when the concentration was the same.

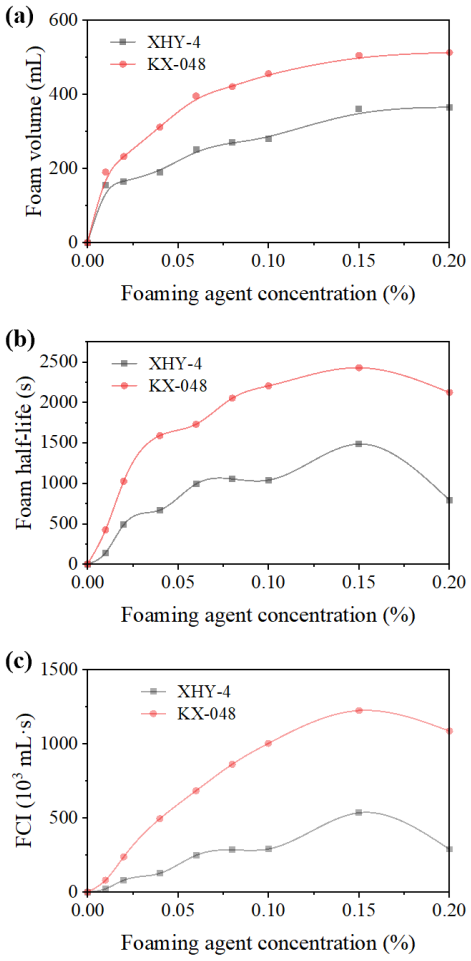



**Figure 6.** Foam volume (**a**), foam half-life (**b**), and foam comprehensive index (**c**) of XHY-4 and KX-048 foam systems.

With the obtained foam volume and foam half-life, the foam comprehensive index could be calculated according to Equation (1). The foam comprehensive indexes of both the two foam systems under each condition have been shown in Figure 6c. In both cases, the foam comprehensive index reached a maximum at a concentration of 0.15%. Additionally, the performance of KX-048-generated foam was much better than XHY-4-generated foam.

The above results indicated that the performance of the KX-048 foam system was better than that of XHY-4 foam systems under all conditions. Additionally, for both of them, with the increase of foam agent concentration from 0 to 0.20%, the foam volumes gradually increased, while the foam half-lives and foam comprehensive indexes first increased and then decreased. Additionally, for the optimum concentration of KX-048 reducing heavy oil viscosity, which was 0.1%, the foam volume was 455 mL, foam half-life was 2201 s, and the foam comprehensive index was $1.00 \times 10^6$ mL·s.

### *3.3. Mobility Ratio Control of Foam Systems*

Mobility refers to the ratio of the effective permeability to the viscosity of a fluid in a porous medium. Mobility ratio refers to the ratio of flooding phase mobility to the flooded phase mobility. Mobility ratio is directly related to sweep efficiency. It could be calculated according to Equation (2):

$$M = \frac{\lambda_d}{\lambda_o} = \frac{K_d/\mu_d}{K_o/\mu_o} = \frac{K_d}{K_o} \cdot \frac{\mu_o}{\mu_d} \quad (2)$$

in which $M$ is the mobility ratio, dimensionless; $K_d$ is the effective permeability of the flooding phase in $10^{-3}$ μm$^2$; $K_o$ is the effective permeability of the flooded phase in $10^{-3}$ μm$^2$; $\mu_d$ is the viscosity of the flooding phase, in mPa·s; $\mu_o$ is the viscosity of flooded phase, in mPa·s. When the mobility ratio is larger than 1, the mobility of the flooding phase is higher than that of the flooded phase. The flooding age was unstable, and viscous fingering could happen. Only when the mobility ratio was lower than one, the mobility ratio was beneficial for flooding steadily.

The control of mobility ratio could be realized by adjusting the mobilities of the flooding phase and/or flooded phase. When synthetic brine was pumped into the sand-pack models, its mobility was not significantly affected by flooding linear velocity. With linear velocity increased from 0.59 to 5.88 m/d, the brine mobility changed only from 566 to 534 × $10^{-3}$ μm$^2$/mPa·s. It means that the water mobility was quite high. It is well-known that water channeling could happen in heterogeneous formation when water mobility is too high, resulting in inferior recovery efficiency.

The mobility of the oil phase is the other important factor that also significantly affects the mobility ratio of water flooding. The experiment results showed that the mobility of the original crude oil at 1.47 m/d linear velocity was 4.71 × $10^{-3}$ μm$^2$/mPa·s. The addition of surfactants into heavy oil could significantly improve mobility. For example, the mobility of heavy oil at 1.47 m/d linear velocity was increased to 5.78 × $10^{-3}$ μm$^2$/mPa·s when there was 0.15% XHY-4. However, the same amount of KX-048 could increase the corresponding oil mobility to 17.69 × $10^{-3}$ μm$^2$/mPa·s. With the change in oil mobility, the water/oil mobility ratio was significantly changed. When linear velocity was 1.47 m/d, the water/oil mobility ratio for original oil was 116.33; for oil with 0.15% XHY-4, it was 97.95, and for oil with 0.15% KX-048, it was 30.97. The addition of KX-048 surfactant significantly decreased the water/oil mobility ratio, with a decrease of 73.37%. As shown in Figure 7a, the change of linear velocity resulted in only a slight decrease in the water/oil mobility ratio caused by the increase in oil mobility. These results indicated that the surfactants, which could decrease oil viscosity, could improve the water/oil mobility ratio, which would be beneficial for enlarging sweeping efficiency. It has been proved that the addition of a foaming agent could significantly improve the water/oil mobility ratio. Moreover, the concentration of foaming agents was also an important factor affecting the mobility ratio improvement. As shown in Figure 7b, without a foaming agent, the water/oil mobility ratio at 1.47 m/d linear velocity was as high as 116.33. With the increasing foaming agent concentration for both XHY-4 and KX-048, the water/oil mobility ratio gradually decreased.

Foams have high apparent viscosity. Bubbles change their shape when going through pore throats, which increases mobility. Different foam systems have different mobility. Foam systems with lower mobility could induce lower gas permeability, improving the foam/oil mobility ratio. Figure 7c shows the foam/oil mobility ratio at different linear velocities for the two foam systems. The results showed that the increase in linear velocity could induce an increase in the foam/oil mobility ratio. When linear velocity was 0.59 m/d or 1.47 m/d, the stability of the foam was good, and the foam/oil mobility ratio was low. For both the foam systems of XHY-4 and KX-048, the mobility of the generated foam was not significantly different. However, as KX-048 could induce more mobility increase for the oil phase, the foam/oil mobility ratio was lower. For example, when linear velocity was 1.47 m/d, the foam/oil mobility ratio for XHY-4 was 0.89, while for KX-048, it was 0.28. It means that the KX-048 foam system could effectively control the planar motion of the flooding phase, avoiding channeling and fingering. Moreover, it should be noted that the

concentration of foaming agents also significantly affected the foam/oil mobility ratio. As shown in Figure 7d, with increasing foaming agent concentration from 0.025% to 0.10%, the foam/oil mobility ratio significantly decreased. When it kept increasing from 0.10% to 0.15%, the foam/oil mobility ratio did not change much. This trend was the same for both XHY-4 and KX-048.

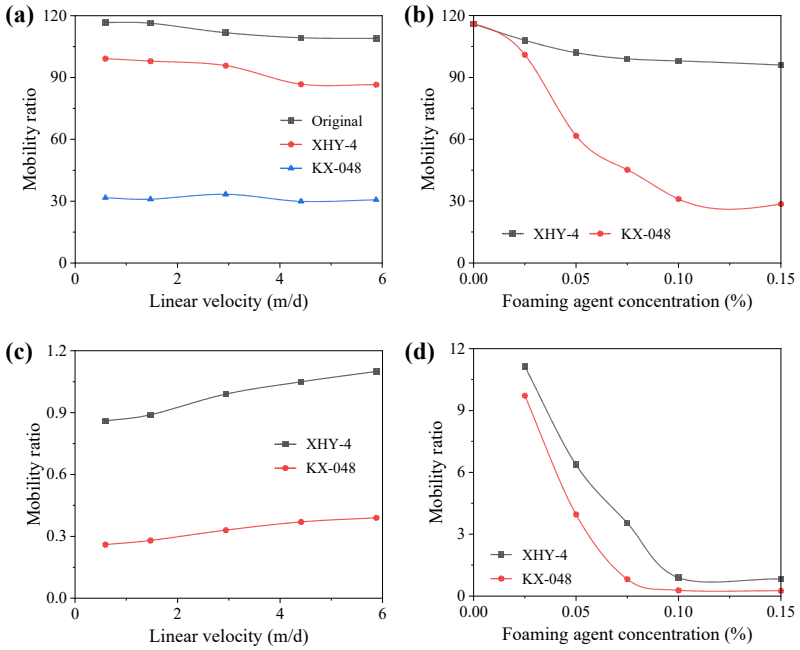



**Figure 7.** Mobility ratio control of foam system in sand-pack models. Water/oil mobility ratio at different linear velocities (**a**) and at different foaming agent concentrations (**b**). Foam/oil mobility ratio at different linear velocities (**c**) and at different foaming agent concentrations (**d**).

The above results indicated that the usage of the KX-048 foaming agent could improve both the water/oil mobility ratio and foam/oil mobility ratio much better than the XHY-4 foaming agent, although the changing trend of the mobility ratios with the change of linear velocity or the change foaming agent concentration was similar.

### *3.4. Enhanced Heavy Oil Recovery with Foam Systems (Heavy Oil Viscosity Reduction)*

As foam systems have high apparent viscosity, they can enlarge the sweeping efficiency in flooding oil. To investigate the improvement in the two studied foam systems on oil recovery, flooding experiments were carried out in heterogeneous double-tube sand-pack models. Table 3 shows the parameters of the prepared sand-pack models. The permeabilities and permeability ratios were similar. Figure 8a,b show the results of foam flooding experiments. For both cases, water flooding could recover over 65% of oil in high-permeable tubes. While in low-permeable tubes, the recovery was about 10%. Additionally, the overall recovery was about 40%. After foam flooding started, oil was continuously recovered from high-permeable tubes. The high-permeable tube recovery increased by 15.67% for KX-048 and 11.11% for XHY-4. Compared with high-permeable tubes, the increase in oil recovery was more significant for low-permeable tubes. For KX-048, the increase in oil recovery from low-permeable tubes reached 24.71%, and the increase in overall oil recovery was 19.96%. The corresponding values for XHY-4 were 12.10% and 11.57%, respectively. From these results, it could be found that the KX-048 foaming agent had better efficiency in improving oil recovery. This was because when the KX-048 foam system was used to flood oil, the foam/oil mobility ratio was lower than the case of the XHY-4 foam system, making the probability of channeling and fingering lower. Figure 8c shows the gas feature in the flooding process. In the case of the KX-048 foam system, gas was collected at the end of the sand-pack model in a longer time than in the case of XHY-4,

meaning that KX-048 could reduce gas channeling and fingering better, postponing the breakthrough of the gas phase in foam flooding. To further confirm the viscosity reduction in heavy oil induced by foam agents, the viscosity of the harvested oil was investigated (Figure 8d). The results showed that with the increasing injection volume, the viscosity of harvested oil became lower and lower. Moreover, the decrease in oil viscosity was much larger in the case of KX-048 than in the case of XHY-4. The viscosity reduction in heavy oil definitely formed another main reason for the improvement in heavy oil recovery.

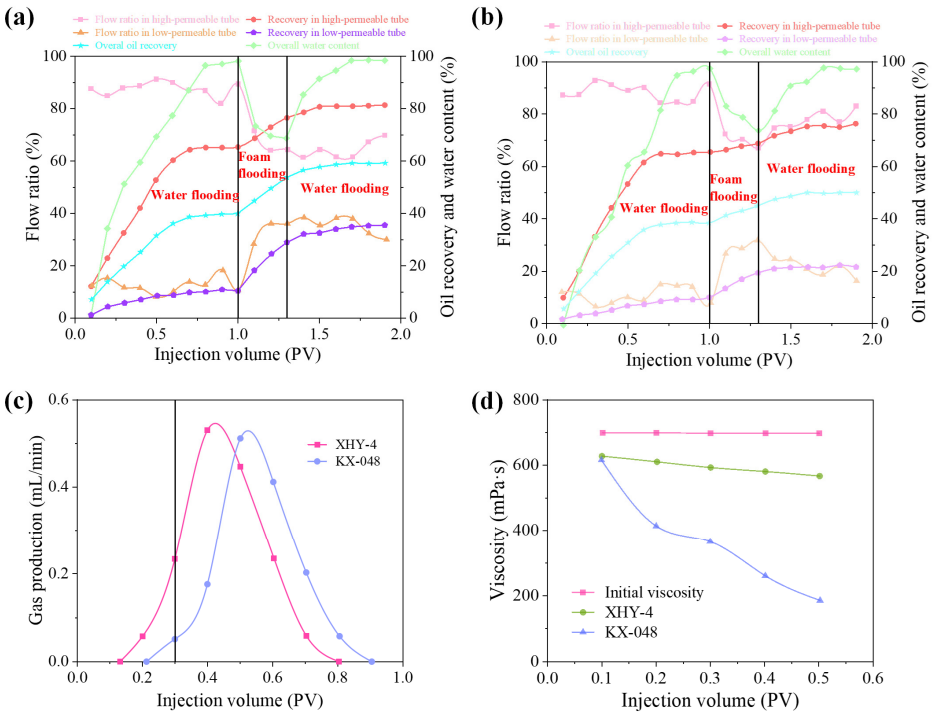



**Figure 8.** Foam flooding experiment results in sand-pack models. Oil recovery, water content, fractional flow at different injection volumes for KX-048 (**a**) and XHY-4 (**b**); (**c**) Gas production at different injection volumes; (**d**) Viscosity of oil harvested at different injection volumes.

Foam systems had high apparent viscosity, which was beneficial for improving sweeping efficiency. The experimental results of flooding heavy oil indicated both KX-048 and XHY-4 could block the high-permeable tube, increase the sweeping efficiency in a low-permeable tube, and improve the whole oil recovery. However, the advantages of KX-048 on XHY-4 were also obvious. Compared with XHY-4, the usage of KX-048 resulted in a later gas breakthrough, indicating better performance in controlling gas channeling. The viscosity of the harvested oil also demonstrated that the oil harvested from KX-048 foam flooding showed lower viscosity. As a result, the whole oil recovery was improved much more in the case of KX-048 (19.96%) than in the case of XHY-4 (11.57%).

## 4. Conclusions

The poor mobility caused by high viscosity is the main cause of the difficulty of heavy oil harvesting. Although varieties of methods that could reduce the viscosity of heavy oil have been tried, new methods with low cost and high efficiency are still needed. Foam flooding is one of the cheapest methods for oil recovery. When applied to heavy oil, it could not only improve the mobility ratio but also reduce the viscosity of oil. The double effects might result in significant oil recovery. However, the key point here is to find suitable foam systems. Therefore, in the present work, the viscosity reduction in heavy oil caused by the foaming agent was studied. Compared with the other studied foaming agents, the KX-048 foaming agent had the best oil viscosity reduction performance (93.71% viscosity reduction at 0.1% concentration). It also showed excellent foaming performance, including

large foam volume (150 mL foam generated from 100 mL solution at 0.15% concentration), long foam half-life (2425 s at 0.15% concentration), and high foam comprehensive index ($1.22 \times 10^6$ mL·s. at 0.15% concentration). With the reduction in oil viscosity, the KX-048 foaming agent decreased the foam/oil mobility to 0.28, which was beneficial for controlling gas channeling and fingering in foam flooding. Moreover, Foam flooding experiments in heterogeneous sand-pack models indicated that KX-048 had excellent efficiency in improving oil recovery, especially in the low-permeable tube. With foam flooding with the KX-048 foam system, a gas breakthrough happened later, and the harvested oil showed lower viscosity. All the results indicated that the chosen KX-048 foaming agent could provide a promising pathway for improving heavy oil recovery.

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