Effect of in Situ Formed Emulsions on Enhanced Extra-Heavy Oil Recovery by Surfactant Flooding

Xiuyu Wang1, Xiaoqiu Wang1,*, Lichuan Lei1, Yang Guo2, Yongzhi Yang3,Yaping Xu1, Huimin Hao1
1China Petroleum Engineering Department, China University of Petroleum, Beijing, China
2Army Logistics University of PLA, Chongqing 401331, China
3Research Institute of Petroleum Exploration & Development, Beijing, China
Email: wangxiaqiu@cup.edu.cn

Abstract. Thermochemical flooding is becoming more popular nowadays as a subsequent EOR method after thermal recovery in extra-heavy oil reservoirs. During this process, in-situ emulsions could happen due to interfacial active components existing in heavy crude oil. The enhanced oil recovery is inevitably related with the formation of emulsions, which is one of the main mechanisms and deserves a thorough study. Also, the features of relative permeability curves during thermochemical flooding should be investigated further, because they are very important but usually are difficult to obtain since physical reactions could happen. Based on core-flooding experiments, combined with careful observation of produced crude oil emulsion morphology, this paper compared and analyzed the features of relative permeability curves and displacement efficiency at different conditions, and the mechanisms of extra-heavy oil production by surfactant displacement is then investigated. The surfactant used are provided by the oilfield at a varied mass fraction of 0.1%, 0.2% and 0.3 % and under temperature of 100, 150 and 180 ℃. The relative permeability data were processed with JBN method. The experimental results show that both the oil and water relative permeability increase as the temperature increases. As surfactant concentration increases, the relative permeability of the aqueous phase decreases as opposite to oil. The ultimate recovery increased with the increase of temperature and surfactant concentration. Except for the oil viscosity reduction by surfactant, it is interesting to note that the formation of crude oil emulsions (mainly O/W emulsions) are observed to be positively impacting the oil recovery factor. As surfactant concentration increases, larger size of dispersed phase in the emulsions were observed in the effluent corresponding to a higher oil recovery factor. This work is of great significance for heavy oil research and field development.

1. Introduction
The heavy oil is referred to the crude oil with a viscosity of 50 mPa·s at reservoir conditions. The prominent characteristic of heavy oil is its temperature sensitivity, and it is difficult to develop at an economic level due to large flow resistance due to large asphaltene content and high viscosity. The oil used in this study is from Liaohe oil field with viscosity greater than 10000 mPa·s at 60 ℃ and belongs to Extra-heavy oil. In China, thermal recovery method is generally used for heavy oil reservoir, such as hot water flooding and steam flooding. However, it is found in recent years that more efficient way is to apply thermochemical method to improve the production behavior of extra-heavy oil reservoirs. To
better apply this method for field production, relative permeability data is of great significance to be obtained and displacement procedures should be evaluated at lab scale. Most researchers have investigated relative permeability feature of heavy oil reservoir, and the temperature effect on the flow behavior[1-5]. However, little literature was found for extra-heavy oil reservoir. For mechanism study, there were some previous literature about chemical flooding in heavy oil reservoirs, stating that the emulsion may play an important role[6-12]. However, most previous work was done for alkali flooding and very little about surfactant flooding method. Furthermore, in this study, the emulsion type and particle size distribution was carefully investigated during the experiments and direct relationship between particle size and displacement efficiency was found.

2. Experimental setup and Experimental procedures

2.1. Experimental devices and materials

The experimental devices mainly include pump, thermos-static chamber, core flooding system and Oil-water metering device (figure 1). The pump is Teledyne ISCO pump. The core flooding system is composed of core holder and high pressure fluid containers. Pressure and the flowrate is recorded densely at different time interval.

![Figure 1. The experimental setup for relative permeability curve measurement.](image)

The cores are artificial sandstone with a diameter of 2.54 cm and length around 7 cm. The permeability ranges from 3000 mD to 3600 mD. The experimental water is NaHCO₃ type formation water, with a total salinity of 2133 mg/L. The oil was obtained from Xinglongtai formation in Du84 block of Liaohe oilfield. The viscosity-temperature curve indicates that the crude oil does not flow at laboratory temperature (30 ℃), at which the viscosity can reach 290×10⁴ mPa·s. The viscosity of this dead oil at different temperature from 30 ℃ to 200 ℃ is measured as shown in 'figure 2. The viscosity decreases sharply to 58×10⁴ mPa·s when the temperature rises to 40 ℃, and there is an inflection point of crude oil viscosity at 70 ℃. After 100 ℃, the decrement of crude oil viscosity slows down as temperature increases. The surfactant used in this work is provided by the oil field and mainly functions as viscosity reducer.
Figure 2. The viscosity of dead oil at different temperature.

2.2. Experimental procedures
The relative permeability and recovery factor of heavy oil and surfactant at 0.1%, 0.2% and 0.3% mass fraction and under 100 ℃, 150 ℃ and 180 ℃ were investigated by unsteady state method. Hot water flooding at different temperature was also performed as blank tests. The experiments were done according to the following procedures:

① Firstly, the cores were saturated with water, and then oil was injected into the cores until the irreducible water saturation ($S_{wi}$) was reached.

② Suitable displacement rate were determined based on Rapoport criterion. Data was recorded more densely immediately after water breakthrough. The experiments were ended when the water cut reaches 99.5% and the pressure difference becomes stable.

③ Produced liquid were heated to break the emulsions and generate accurate oil and water data. Finally, the relative permeability curve is processed by JBN method. This work also did a serious of pipeline flow experiments at different conditions to calculate the dead volume of oil in the pipeline in order to correct fluid volume for accurate data processing.

3. Experimental results

3.1. Analysis of relative permeability curve
The relative permeability curves by hot water flooding and surfactant flooding at different concentration at 100 ℃, 150 ℃ and 180 ℃ are shown separately from figure 3(a) to figure 3(c).
With the concentration of surfactant increases from 0%(hot water) to 0.1% to 0.3%, the oil relative permeability ($K_{ro}$) becomes larger and the water relative permeability ($K_{rw}$) becomes smaller and the mobility ratio becomes more favorable. $K_{rw}$ increases rapidly right after water breakthrough and then its uplift is obviously inhibited probably due to the formation of crude oil emulsions, which will be explained in details in next section.

The width of two-phase flow zone is enlarged as temperature increases. For example, at 0.3% surfactant, the width of two-phase flow zone increases from 0.39 to 0.45 and 0.49 as temperature increases from 100℃ to 150℃ and 180℃.

3.2. Analysis of recovery efficiency

The recovery efficiency changing with different pore volume (PV) of displacing agent injected at 100 ℃, 150 ℃ and 180 ℃ are shown from figure 4(a) to 4(c). It can be seen that the recovery efficiency with surfactant flooding increases greatly compared with hot water flooding and it also increases as surfactant concentration increases. For example, the final oil efficiency at 0.3% surfactant is increased by more than 3.2% OOIP at 150 ℃ than it at 150 ℃. At 180 ℃, the oil viscosity reduces more and water-oil mobility ratio is lower so that the recovery efficiency is improved. Also, the O/W emulsion plays an important role of emulsifying and carrying oil droplets, so that the crude oil remained at the corner of the pore throat can be displaced.
3.3. Investigation of oil displacement mechanisms

The surfactant used in this experiment is not only functioning as a viscosity reducer, but also acts as an emulsifier as it decreases interfacial tension between water and oil. It was found that the emulsions formed during the displacements were mainly O/W emulsions, but showing different morphology at different stages during displacement process. In the middle and late stage, as water cut increases, the viscosity of the O/W emulsion is very low, and the small oil droplets on the side of the percolation passage are continuously carried out, which contributes to the oil recovery factor.

Another mechanism is improvement of microscopic sweeping efficiency by formation of O/W emulsions. The effluent sampling shows that there are emulsions with a particle size about 5μm or more at 0.2% and 0.3% surfactant. The emulsion particles increase the flow resistance of water due to Jamin effect, and divert the water to flow through smaller pores. This effectively delays water breakthrough time. The morphology of emulsions obtained from different experiments were carefully observed under microscope with 350 times magnification. To be concise, only the microscopic pictures and the particle size statistics of emulsions from effluents at 100 °C are shown in Figure 5. And the comparison between the emulsion morphology at 0.3% surfactant at 100 °C, 150 °C and 180 °C is shown in Figure 6.
Figure 5. Emulsion morphology and particle size distribution at 100 °C from surfactant flooding at different concentration. (a) and (b): 0.1% surfactant flooding; (c) and (d): 0.2% surfactant flooding; (e) and (f): 0.3% surfactant flooding;

Figure 6. The comparison of emulsion morphology from 0.3% surfactant flooding at different temperature. (a): 100 °C; (b): 150 °C; (c): 180 °C.
At 100℃, the effluent is almost clear and the black heavy oil droplets float in the upper layer and less emulsions were observed. At 150 ℃, the effluent colour changes to brown and dark brown. A large number of black oil belts float in the effluent at early stage of displacement, which becomes a small number of black oil droplets in the middle and late stage of displacement. At 180 ℃, emulsions are more readily to be formed.

Figure 5 shows that the average particle size in the 100 °C test was 3.30μm, 3.38μm, and 4.36μm for 0.1%, 0.2% and 0.3% surfactant, respectively, indicating that the particle size of the emulsion particles in the produced liquid increases as the mass fraction of the surfactant increase. It is also noteworthy to point out that for 0.3% surfactant, about 25% of emulsion particles are distributed in the range of 5μm to 12μm, which is much higher than 0.1% and 0.2% surfactant.

At 150 ℃, larger particle size of O/W emulsion particles and W/O/W emulsion particles were observed in the effluent. The average particle diameter of the emulsions is 3.36μm, 4.41μm, and 6.90μm for 0.1%, 0.2% and 0.3% surfactant respectively and they are 3.97μm, 4.89μm, and 5.89μm at 180 ℃. It is interesting to find that the emulsion particles are larger and more densely distributed at higher surfactant concentration and higher temperature, and even some 35μm emulsion particles are present during 0.3% surfactant flooding at 180 ℃.

4. Conclusions

(1) The relative permeability curves of the extra-heavy oil obtained from Liaohe Oilfield have significant characteristics. When the surfactant concentration is low, the water breakthrough is early, resulting in a comparatively steep relative permeability curve of oil phase. At the same temperature, as the surfactant increases, \( K_{ro} \) increases and the end point of \( K_{rw} \) decreases.

(2) When the surfactant concentration increases while keeping the experimental temperature constant, the residual oil saturation decreases and the ultimate recovery factor increases. Extra-heavy oil recovery efficiency by hot water is found to be the lowest compared with surfactant flooding.

(3) One of the reasons for the improved displacement efficiency of extra-heavy oil by surfactant flooding is the oil viscosity reduction by surfactant. The other important mechanism should be attributed to the emulsification and carrying effect of O/W emulsions. At the same experimental temperature, when the surfactant concentration increases, the average diameter of the emulsion particles is larger and resulting in improved oil recovery efficiency.

(4) As experimental temperature increases from 100 ℃ to 150 ℃ and 180 ℃, the displacement efficiency of extra-heavy oil by surfactant flooding increases. The mechanism underlying this phenomenon can also be attributed to emulsion formation and oil viscosity reduction.

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