VISUAL INVESTIGATION OF LOW SALINITY WATERFLOODING

Alireza Emadi and Mehran Sohrabi

Centre for Enhanced Oil Recovery and CO2 Solutions, Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh, UK

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ABSTRACT

Low salinity waterflooding (LSW) has been reported to improve oil recovery in numerous laboratory and field experiments. The general assumption among researchers is that LSW shifts wettability towards a more favourable wetting state for oil recovery. However, a consistent theory to explain the process of wettability modification has not yet emerged. This paper presents the results of a series of visual experiments performed in transparent micromodels to investigate the mechanisms involved in LSW. We show by vivid images of micromodels that when low salinity water comes in contact with some crude oil samples it results in formation of a large number of water micro-emulsions at the oil/water interface. Having higher density compared to oil, the micro-emulsions may precipitate at the bottom of the oil blobs in vertically oriented systems, if enough time is given. In the micromodel tests the formation and disappearance of these micro-emulsions was associated with slight change in the wettability of the system. The hypothesis proposed here suggests that when the water micro-emulsions form they are covered by surface active agents in the oil phase. As the number of water micro-emulsions increases, the oil-water interface is depleted from surface active agents or at least a group of them. This results in alteration of the charge at oil-water and oil-mineral interfaces and wettability alteration in the system. Using the visual results from this study, we introduce depletion of the oil/water interface from surface active agents, associated with formation of water micro-emulsions, as a contributing mechanism to wettability alteration and improved oil recovery.

INTRODUCTION

Improved oil recovery by injection of LSW was first reported by Tang and Morrow (1997). Since then, there has been substantial amount of research on low salinity effect (LSE) to explore the potential of LSW as an enhanced oil recovery technique and to understand the underlying mechanisms. Whilst it is generally accepted that lowering water salinity can improve basic waterflood performance in certain conditions, a consistent mechanistic explanation has not yet emerged. In part it may be the result of the use of different materials and variations in test procedures. The complexity of the minerals, crude oils, and aqueous phase compositions and the interactions among all these phases also may contribute to confusion about the cause of LSE. The variety of circumstances under which LSE may or may not be observed suggests that more than one mechanism may be in play.

The general assumption among researchers is that injecting low salinity water creates a wetting state more favourable to oil recovery (Morrow and Buckley, 2011). Alteration of wettability affects the microscopic distribution and flow of oil and water in porous media and thus the residual oil saturation. Different mechanisms have been proposed in the literature to explain the process of wettability alteration during LSW including; migration of fine particles (Tang and Morrow, 1999), multi-component ion exchange (Lager et ad, 2006), expansion of electrical double layers (Ligthelm et.al., 2009), salt-in effect (RezaeiDoust et. al., 2009), and pH elevation (McGuire et al, 2006). Evidence for change in wettability is often indirect such as from changes in relative permeability curves or centrifuge capillary pressure (Morrow and Buckley, 2011). The most direct, but less frequently used, techniques of wettability investigation are spontaneous imbibition and flow visualization tests. While there are few spontaneous imbibition tests reported in the literature, the use of the glass micromodels for the purpose LSW has grabbed much less attention. Visualization tests offer a unique advantage of direct and real time analysis of the wettability while the low salinity water is injected in different injection strategies. Additionally, the interactions between oil and low salinity water (if any exist) can be visually detected and then compared to the case of high salinity waterflooding. As the main mechanisms in oil recovery by LSW is not clear yet, direct visualization tests can improve our understanding and help to develop a theory to predict the performance of LSW under different conditions. The insights from the micromodel experiments can be then confirmed and quantify through core flood experiments.

This paper presents the results of a set of three micromodel tests carried out to investigate the mechanisms and interactions involved in LSW. The first test is the base case in which high salinity water is used as both connate water and flood water. The second test is similar to the first test with the only difference being that high salinity water is replaced by low salinity water. In the third test, low salinity waterflood is applied after an initial period of high salinity waterflood to simulate process of low salinity waterflooding in tertiary mode.

EXPERIMENTAL

A high-pressure micromodel rig was used to perform the micromodel experiments. Table 1 shows the dimensions of the vertically oriented micromodel and their pores. Details of the experimental facilities can be found elsewhere (Sohrabi et al. 2000). Table 1 presents the basic properties of the crude oil used in this study. The crude oil was centrifuged and filtered before being injected in the rig. A high salinity (30000 ppm) and a low salinity (500 ppm) water solutions were used in this study as the aqueous phase which are listed in Table 2. Water was injected from the top end of the vertical micromodel at a very slow rate of 0.01 cm^3/hr which corresponds to a capillary number of ca. 2.5 E-7. This series of micromodel tests were performed at pressure and temperature of 600 psig and 44 °C.

RESULTS

Test 1: In the first micromodel test, the process of conventional waterflooding was simulated; in which a high salinity water (brine type 1) was used as connate and flood water. Micromodel was first saturated with high salinity water and then flooded with oil to establish the initial oil and water distribution (Figure 1a). Micromodel was then flooded with high salinity water which continued for an extended period of time (Figure 1b). Continuation of waterflood (up to 50 PV's) after breakthrough did not result in additional oil recovery or changes of fluid distribution in the system.

Test 2: The second test was performed using a procedure similar to that of the first test; however, the high salinity water was replaced by a low salinity water (brine type 2) as both connate water and flood water. One important observation in test was darkening of the crude oil when it came in contact with the low salinity water. The very high magnification pictures of the micromodel revealed that this change of colour is in fact a consequence of formation of very fine particles at the oil/water interface. When waterflood continued for an extended time period, these dark particles gradually precipitated at the bottom of separated oil blobs and colour of oil became brighter. The red arrows in Figure 2 illustrate the pores in which precipitation of the dark particles is apparent. Nevertheless, the oil/water distribution remained unchanged during the extended period of waterflood.

Test 3: In the third test, to simulate the process of low salinity waterflooding in tertiary mode, the high salinity water was used as the connate water. The micromodel was then flooded by crude oil (Figure 3a) and subsequently by the high salinity water for 3 PV's (Figure 3b). At this point, injection of the low salinity water started and continued for 50 PV's. Initially, injection of the low salinity water resulted in darkening of the oil colour and formation of dark particles in those parts of the crude oil which were closer to the flowing path of water (the red arrows in Figure 3c). However, as injection of low salinity water continued, the dark particles were also observed in the oil blobs which were further from flowing path of water. When injection of low salinity water continued for an extended period of time the dark particles precipitated and the oil colour returned to its original colour (Figure 3d), similar to the observations made in the second test. The extended period of low salinity waterflood carried out in this test was associated with slight modification in water/oil distribution in the micromodel.

DISCUSSION

Interaction between Oil and Low Salinity Water

The results of this series of micromodel tests shows that there are certain interactions in the oil phase when it comes in contact with low salinity water. These interactions, which were described here as formation of dark particles, take place if low salinity water is used either as connate water or as flood water and may result in re-distribution of fluids in the porous media. In other tests (not reported here) in which low salinity water injection was followed by high salinity waterflood, the dark particles disappeared in the system and instead small water droplets formed. Formation of water droplets inside the oil phase, after disappearance of the dark particles, implies that the dark particles are micro-emulsions of water in oil. However, the water micro-emulsions are required to be covered by polar components of the oil in order to remain stable in the oil phase. Our hypothesis to explain this behaviour is that when crude oil is in contact with a high salinity water, the surface active agents of the crude oil accumulate at the oil/water interfaces. Since the bulk of the oil is poor in surface active agents, there are limited numbers of water micro-emulsions in the oil phase. If the ionic strength of the water is lowered (low salinity level), polar components would leave the oil/water interface towards the bulk of the oil phase. Presences of surface active agents in the oil stabilize the water micro-emulsions and hence, their number dramatically increases. When high salinity water is injected in the system again, the polar components return to the oil/water interface and leave the water micro-emulsions. Therefore, the micro-emulsions become unstable and collapse forming the droplets of water observed inside the oil phase. The segregation of the dark particles in the oil phase, which was observed in tests 1 and 3, is believed to be as a result of the density difference between the water micro-emulsions and the oil.

Wettability Alteration

Injection of the low salinity water did not cause additional oil recovery in the tests which were reported here, however slight modification was observed in oil/water distribution when low salinity water was injected subsequent to a period of high salinity waterflood (test 3). The weak response to low salinity waterflood, in terms of wettability alteration and incremental oil recovery, is believed to be due to lack of clay particles and divalent ions in the micromodel tests reported here. In real reservoir conditions (presence of clay particles and divalent cations), the observed interaction between low salinity water and crude oil may play an important role in wettability alteration. Our hypothesis is that injection of low salinity water results in depletion of the oil interfaces from part of surface active agents which causes wettability modification in the system, either through alteration of electrostatic forces or by removal of cation bridges between oil and mineral surfaces. For instance, if density of negatively charges sites on oil surface decreases as a result of low salinity water injection the multivalent cation bridges on the oil/rock surfaces could lose the leg connected to the oil. Thus, the oil is desorbed from the rock surface and the state of the wettability alters towards increased water-wetness.

CONCLUSIONS

- The results of this series of micromodel tests reveal certain interactions between crude oil and low salinity water which are associated with formation of water micro-emulsions in the oil phase.
- A hypothesis is introduced here in which formation of a large number of water micro-emulsions during low salinity waterflood is attributed to release of surface active agents from the oil/water interface and dispersion in the bulk of the oil. This reduction in oil surface charges may result in change of wettability and release of oil from rock surfaces.
- The observed water micro-emulsions never formed in presence of high salinity water and if they have formed previously they would coalesce as soon as they came in contact with high salinity water

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Table 1: Basic properties of the extra-heavy crude oil used for the experiments.

API	19.1
Viscosity	92 @ 50 °C
Asphaltene Content	0.54 (wt/wt%)
Acid Number	1.31 (mgKOH/gr)

Table 2: Salinity and composition of the brine solutions.

Brine Solution	Total Salinity	Salt Type
Type 1 (High Salinity)	3000 ppm	NaCl
Type 2 (Low Salinity)	500 ppm	NaCl

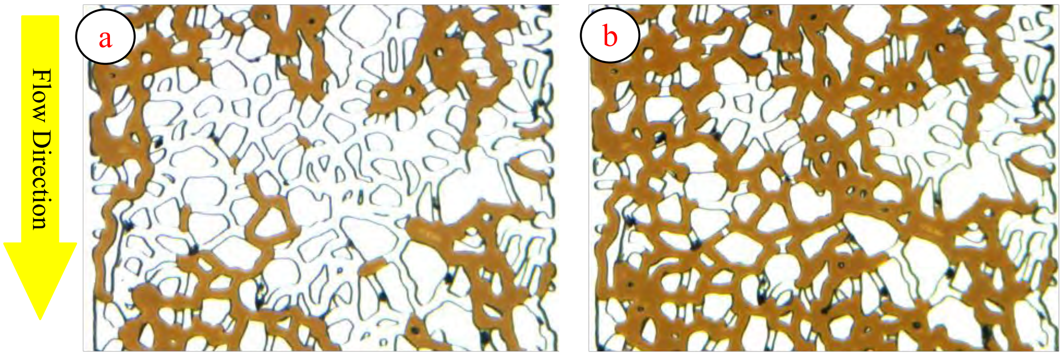

Figure 1: Fluid distribution in a magnified section of the micromodel, after oil flood (a), and waterflood (b) using high salinity waterflood in test 1.

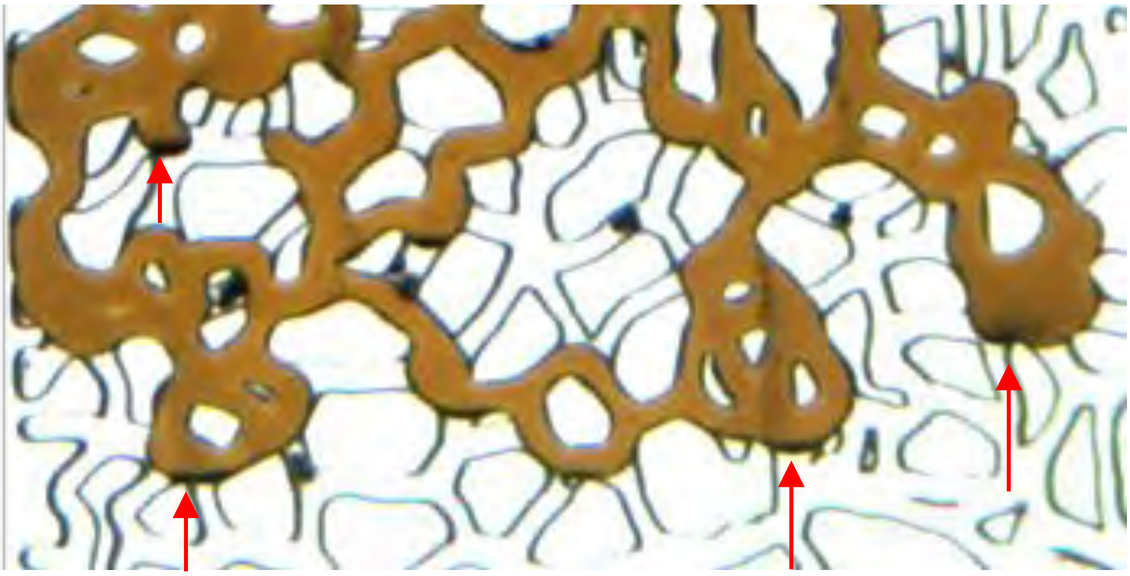

Figure 2: A highly magnified section of the micromodel which clearly shows formation and precipitation of dark particles (water micro-emulsions) in the oil phase during low salinity waterflood in test 2. The red arrows show the locations in which precipitation of dark particles in more apparent.

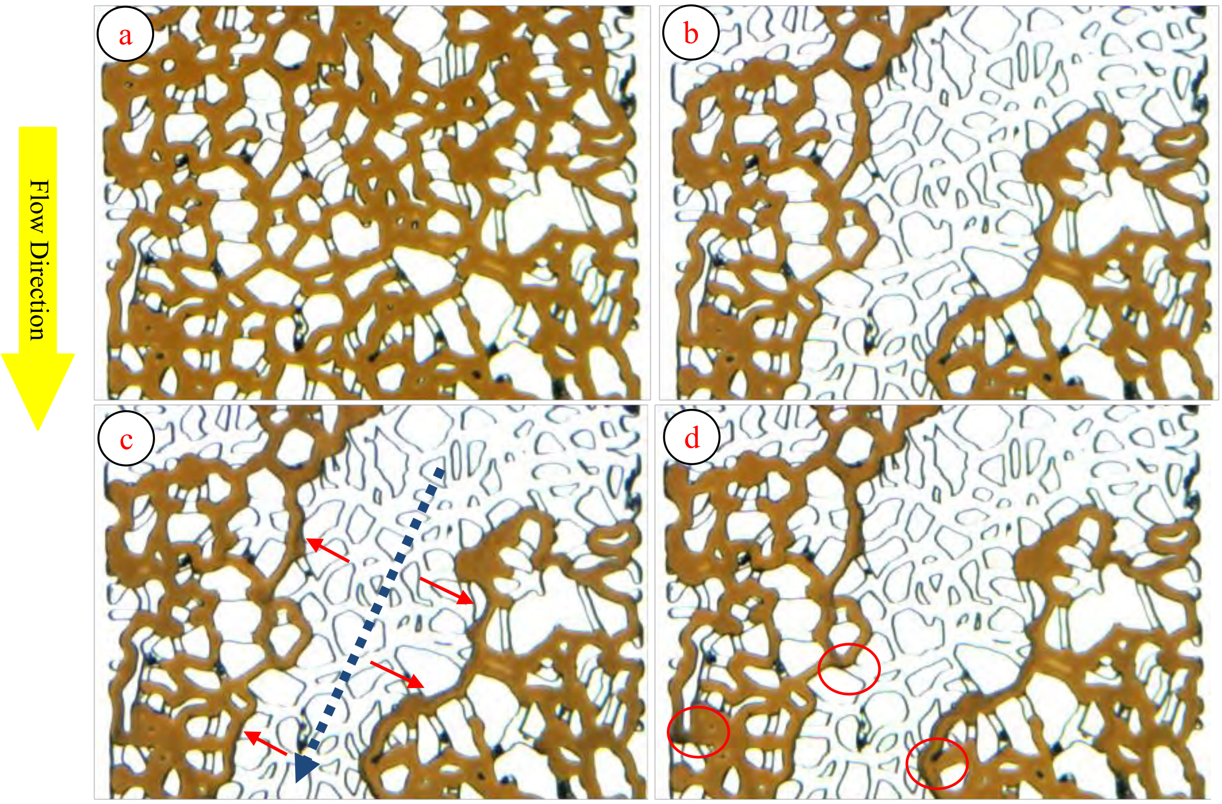

Figure 3: Fluid distribution in the magnified section of the micromodel, after oil flood (a), waterflood using high salinity water (b), early times of waterflood using low salinity water (c) and after extended period of waterflood using low salinity water in test 3.