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Evaluation of low-salinity waterflooding in Middle East carbonate reservoirs using a novel, field-representative coreflood method

Rong Xiao [*], Robin Gupta, Rodney C. Glotzbach, Somnath Sinha, Gary F. Teletzke

ExxonMobil Upstream Research Company, USA

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ABSTRACT

Low-salinity waterflooding attempts to improve recovery by reducing the salinity of the injection water, where the wettability alteration towards more water-wet state of the reservoir rock is believed to be the leading mechanism. This technology has received significant interest and a rich body of unsteady-state coreflooding test data has been reported in the past few years. However, capillary end-effect driven artifacts in conventional unsteady-state coreflooding could hinder proper understanding and interpretation of the measured results. We have developed a modified steady-state fractional-flow method to minimize capillary end effects. The fractional-flow analysis and simulation illustration of the new method has been published earlier by Gupta et al. (2015). In this work, we applied this new method to several Middle East carbonate reservoirs where slight changes in relative permeability consistent with a change in wettability can be observed but the overall uplift in recovery was very small. In addition, the results from the new method and the conventional coreflooding method were compared in selected cases to demonstrate the benefit of the new method in minimizing capillary end effect artifacts. Overall, this work demonstrates an improved laboratory screening methodology for low-salinity waterflood and similar EOR methods. The results of this work highlight the potential as well as challenges in low-salinity waterflooding in carbonates as a practical EOR technology.

1. Introduction

Low-salinity waterflooding is an enhanced oil recovery (EOR) technology where the total dissolved solids (TDS) and ionic strength of the injection brine is reduced to improve waterflooding performance. A significant body of work has been devoted to low-salinity waterflooding in sandstone reservoirs in the past two decades (Morrow and Buckley, 2011). Various laboratory and field tests have been performed to demonstrate the benefit from reduced ionic strength of the injection water (Cissokho et al., 2010; Law et al., 2014; Nasralla and Nasr-El-Din, 2011; Rotondi et al., 2014; Xie et al., 2015). The mechanism in sandstone reservoirs is believed to be the wettability alteration of clay materials towards more water-wet (Alotaibi et al., 2010; Austad et al., 2010).

Given the large potential prize, especially in the Middle East and North Sea, applying low-salinity waterflooding in carbonate reservoirs has received growing interest (Romanuka et al., 2012). The mechanism for carbonates is more complex and not as well understood as in sandstones and is still an active area of research. But most researchers agree that the wettability alteration towards a water-wet condition is the underlying mechanism for low-salinity waterflooding in carbonates (Al Shalabi et al., 2013; Alameri et al., 2014; Mahani et al., 2015a, 2015b, 2017). A large number of laboratory tests have reported recovery uplift from low-salinity waterflooding with considerable variation (Al-adasani et al., 2015; Al-Attar et al., 2013; Al Harrasi et al., 2012; Nasralla et al., 2014, 2016; Sorop et al., 2015).

In addition to the inherent complexity of carbonate systems, the conventional unsteady-state coreflooding method could also contribute to variations in the experimental results by introducing significant capillary end effects (CEE). In previous work, a novel coreflooding method, the Intermediate Fractional Flow (IFF) method, was developed to minimize capillary end effects and mimic actual field conditions (Gupta et al., 2015). In this paper, we demonstrate the application of this new method in selected Middle East carbonate reservoirs. Slight wettability alteration was observed in most of the cases but the total incremental recovery was small. In some cases, a comparison between the conventional unsteady-state coreflooding method and the new IFF method was shown to highlight the potential contribution from the CEE.

* Corresponding author.
E-mail address: rong.xiao@exxonmobil.com (R. Xiao).

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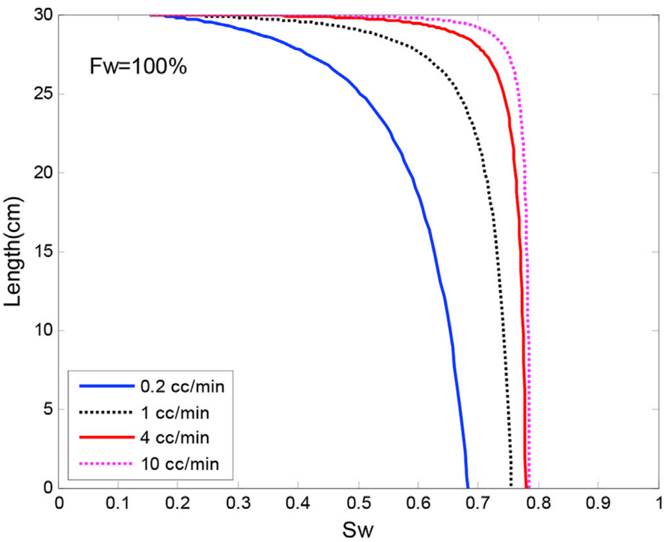


Fig. 1. Calculated water saturation S_w in the core at Fw = 100% and different flow rates under model relative permeability and capillary pressures. A significant capillary end effect can be observed at low flow rates.

2. Method

A brief introduction on the IFF method is included in this section with the focus on minimizing artifacts from capillary end effects. A more detailed discussion of the IFF method is presented in the previous work (Gupta et al., 2015). For a 1D core-flood, the steady-state water--saturation distribution in the core is given by

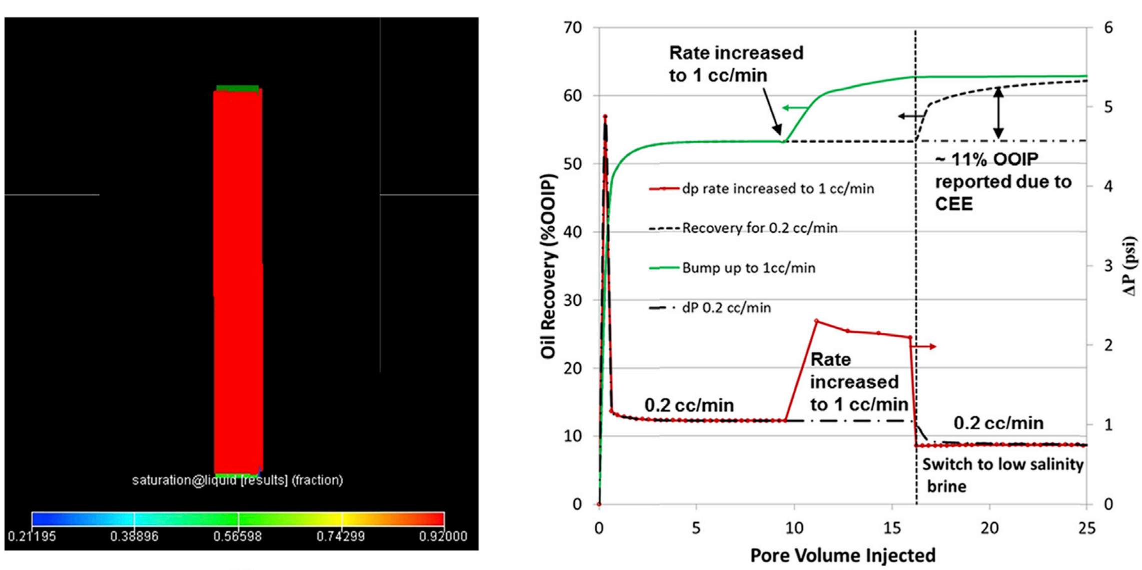
$$\frac{dS_w}{dx} = \left(\frac{dP_o}{dx} - \frac{dP_w}{dx}\right) \Big/ \frac{dP_c}{dS_w}$$

where. $\frac{dP_i}{dx} = \frac{Q_i \mu_i}{K_i(S_w)A} + \rho_i g$, *for* $i = o, w$ The boundary conditions is that the capillary pressure is zero at the outlet.

For illustration purposes, we assume model relative permeability and capillary pressure curves and calculate the water saturation profiles at different flow rates for water fractional flow of Fw = 100%, which corresponds to the case of conventional unsteady-state waterfloods, as shown in Fig. 1. The permeability of the rock in calculation was assumed to be 257 mD. We can clearly observe the capillary end zone where the water saturations near the outlet deviate significantly from the average water saturation in the core. As a result, a significant amount of oil could be "trapped" within this capillary end zone. The trapped oil could be released when the injection fluid was switched, which introduces artifacts to the measured recovery. The length of the capillary end zone and the amount of trapped oil increases with decreasing flow rates. For rocks with lower permeability, the pressure drop at the same flow rates would have been higher, leading to stronger viscous effects and reducing the capillary end effects.

A simulation case is shown in Fig. 2 to highlight such artifacts. A 1-ft long vertical core was set up with zero capillary pressure condition on the outlet and uniform initial water saturation at S_{wir} (Fig. 2(a)). More than 15 PV of a first brine was injected followed by injection of a second brine. The flow rate was constant at 0.2 cc/min. The relative permeability were the same for the two brines as shown in Fig. 1(a). The capillary pressure curve between the oil and the first brine is the same as shown in Fig. 1(b). The interfacial tension (IFT) between oil and water was reduced by half for the second brine, leading to 50% reduction in the capillary pressure. Such level of reduction in IFT has been observed in our lab with significant change of TDS. The oil recovery and pressure drop are shown in Fig. 2(b). With the conventional unsteady-state coreflooding method at low flow rates (0.2 cc/min), the release of trapped oil by the capillary end effect introduced an artificial uplift of as much as 11% OOIP when there was no change in the relative permeability. If a flow rate bump to 1 cc/min was introduced before switching the brine, the capillary end zone would be compressed and no artificial uplift would be reported. However, in practice, high rates for multiple pore volumes would significantly reduce the oil mobility as the oil saturation moves very close to the residual saturation. If the low salinity water alters rock wettability with minimal change in residual oil saturation, to observe the benefit with the conventional coreflood method would be very difficult.

However, flow rates as high as several milliliters per minute may not always be practical, especially if the permeability of the reservoir rocks is low. An alternative approach is to co-inject the oil and the brine at an intermediate fractional flow (IFF) which is less than 100%. Fig. 3 shows



(a) (b)

Fig. 2. (a) The model setup in the simulator. The core was 1 ft long with zero capillary pressure at the outlet and constant water saturation at S_{wir} at the beginning. (b) The simulated oil recovery and pressure drop during the coreflood. As much as 11% OOIP apparent recovery uplift can be caused by 50% reduction in capillary pressures by the second brine. Such artifacts are diminished by a rate bump before switching the brine.