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Surfactant oil recovery in fractured carbonates: Experiments and modeling of different matrix dimensions



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ABSTRACT

Oil recovery from fractured carbonate reservoirs by water flooding is often inefficient due to the commonly oil-wet nature of these rocks and the lack of sufficient spontaneous capillary imbibition driving force to push oil out from the matrix to the fracture network. Chemical processes such as surfactant/alkali-induced wettability alteration and interfacial tension (IFT) reduction have shown great potential to reduce the residual oil saturation in matrix blocks, leading to significant incremental oil recovery (IOR). However, the time required to achieve a significant amount of oil recovery is the most crucial deciding factor in field projects. The magnitude of recovery and response time of any chemical process depends on the degree of wettability alteration and IFT reduction, the nature and density of fracture network, and the matrix block size.

Oil recovery experiments were performed for the same matrix rock and chemical formulation, but for different sized cores to gain a better understanding of the time dependence of the recovery process. The measured oil recoveries were history-matched. The simulation models were then used to predict the recovery response times for larger cores. The controlled and systematic laboratory measurements for several core sizes helped in developing dimensionless scaling groups to aid in understanding the time dependence and the upscaling of laboratory results to field-scale applications.

This finding is significant as it illustrates the extent of wettability alteration and IFT reduction needed in fractured reservoirs. Laboratory measurements and simulation work substantiate the validity and the range of applicability of upscaled procedures and indicate the importance of viscous and buoyancy forces in larger field cases. The results of this work will be useful for the design of future field projects.

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1. Introduction

Water flooding is effective for fractured reservoirs if the rock is water-wet, but most of the fractured reservoirs (around 80%) are mixed-wet to oil-wet carbonates (Treiber et al., 1972; Roehl and Choquette, 1985; Borchardt and Yen, 1989). The recovery factor in these reservoirs depends on matrix permeability, wettability, fracture intensity, and fluid properties (Adibhatla et al., 2005). Alkaline chemicals, such as sodium carbonate, especially in fractured carbonate reservoirs, can diffuse into matrix blocks and may alter wettability from oil-wet to water-wet. In addition, surfactants can alter wettability and reduce interfacial tension (IFT) to increase macroscopic Bond number and, consequently, push water into the matrix.

The oil recovery from fractured carbonate reservoirs is influenced by a combined viscous, gravity, and capillary forces, but can be dominated either by spontaneous imbibition or buoyancy, or

for some mixed-wet rocks, both buoyancy and spontaneous imbibition can be dominant mechanisms. A three-dimensional multiphase multicomponent chemical compositional simulator, UTCHEM, will be used for modeling chemical EOR processes and aiding to develop a dimensionless scaling group in this study.

During the capillary imbibition process in a water-wet highly fractured rock, where there is small pressure gradient across the matrix blocks, water will flow into the matrix rock and oil will be produced via fractures due to capillary pressure by counter-current imbibition. Therefore, positive capillary pressures for water-wet rocks indicate higher water pressure in fractures (than pressure in matrix) which pushes water into matrix blocks by force and displaces oil toward fractures (Babadagli, 2003). However, it should be noted that if there are communication between matrix blocks (i. e. not surrounded by fractures in all directions) or the injection rate is high, the process of co-current imbibition can also happen. The rate of imbibition will be a function of matrix block size and permeability. Unfortunately, for oil-wet fractured carbonate rocks the water imbibition recovery without the presence of surfactant is very low because the initial capillary pressure is negative.

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Imbibition experiments using surfactants that produce low IFT have been done by several investigators (Hirasaki and Zhang, 2004; Seethepalli et al., 2004a, 2004b; Abidhatla and Mohanty, 2006). Hirasaki and Zhang (2004) suggested that the dominant oil recovery mechanism in low IFT imbibition is buoyancy and wettability alteration. With some anionic surfactants, the IFT can be reduced to ultra-low values where the capillary pressure is reduced to nearly zero. When the capillary pressure is nearly zero, other forces must be present to account for the rapid imbibition observed in many experiments. Simulation results by Abbasi-Asl et al. (2010) showed that transverse pressure gradients between the fractures and the matrix can push the surfactant further into the matrix in the dynamic imbibition process. Korrani et al. (2013, 2014) mechanistically modeled wettability alteration due to low salinity waterflooding through coupling a geochemical package, IPHreeqc, with compositional reservoir simulators, UTCHEM and UTCOMP. They modeled wettability alteration dynamically using the total ionic strength. Lashgari et al. (2014a, 2014b) presented a steam-surfactant-foam model by having four-phase flow (steam/oil/water/microemulsion) in equilibrium to reveal the efficiency of hybrid thermal-chemical method in improvement of recovery from heavy oil reservoirs.

Imbibition experiments showed that increasing surfactant concentration raised the recovery rate slightly at early times but did not have a considerable effect on final oil recovery. Lu et al. (2012b, 2014) performed static and dynamic imbibition experiments using new surfactant formulations and investigated the effect of surfactant on IFT reduction and oil recovery. Capillary imbibition is an efficient process for small size blocks and its effectiveness is reduced by increasing matrix block size. If capillary forces are small due to IFT reduction by surfactant, gravity forces will be significant and a combination of wettability alteration and gravity will dominate during the imbibition process.

Laboratory experiments including coreflood and imbibition tests provide an understanding of oil recovery mechanisms and the effectiveness of different chemical formulations. With the improved understanding of the relationship between the surfactant structure and the performance, surfactant formulations are developed that give promising results even under high temperature and high salinity reservoir conditions (Solairaj et al., 2012; Adkins et al., 2012; Lu et al., 2012a). However, the same recovery or recovery rate of lab scale cannot be expected at larger real field cases. The main goal of this study is to use laboratory data as the starting point for upscaling chemical processes to reservoir scales. Without these scale-up studies and comprehensive understanding of involved mechanisms for oil recovery during a chemical flood, it will not be possible to design cost-effective, successful chemical processes for heterogeneous fractured carbonate reservoirs.

2. Model description

Surfactants can alter wettability and reduce IFT to increase capillary number; consequently, residual oil will be mobilized due to reduced capillary forces. UTCHEM has the capability to model wettability alteration for both static imbibition cell and dynamic corefloods. Relative permeability and capillary pressure for each extreme wetting condition in every gridblock will be calculated in every time step based on the Corey model as follows:

$$k_{r\ell} = k_{r\ell}^o S_{n\ell}^{n_\ell}, \quad (1)$$

where ℓ refers to water, oil, or microemulsion phase, $k_{r\ell}^o$ is the endpoint relative permeability, n_ℓ is the exponent, and $S_{n\ell}$ is the

normalized saturation as computed by

$$S_{n\ell} = \frac{S_\ell - S_{\ell r}}{1 - \sum_{\ell=1}^{n_p} S_{\ell r}}, \quad \ell = \text{water, oil or microemulsion phase} \quad (2)$$

where S_ℓ is the saturation, n_p is the number of phases, and $S_{\ell r}$ is the residual saturation.

The altered relative permeability and capillary pressure will be calculated by interpolating between two initial and final wetting conditions using a factor ω which can either be a constant value or be dependent on surfactant adsorption as shown below (Delshad et al., 2006).

$$k_{r\ell}^{\text{altered}} = \omega_1 k_{r\ell}^{\text{final}} + (1 - \omega_1) k_{r\ell}^{\text{initial}} \quad (3)$$

$$P_c^{\text{altered}} = \omega_2 P_c^{\text{final}} + (1 - \omega_2) P_c^{\text{initial}}, \quad (4)$$

where ω_1 and ω_2 are the interpolation scaling factors for relative permeability and capillary pressure, respectively, *final* and *initial* refer to the two extreme wetting states, $k_{r\ell}$ is phase ℓ relative permeability, and P_c is the capillary pressure between pair of phases.

The scaling factors ω_1 and ω_2 in Eqs. (3) and (4) are either constant or dependent on adsorbed surfactant concentration as follows:

$$\omega_1 = \omega_2 = \frac{\hat{C}_{\text{surf}}}{C_{\text{surf}} + \hat{C}_{\text{surf}}}, \quad (5)$$

where C_{surf} and \hat{C}_{surf} are the total and the adsorbed surfactant concentrations calculated in every gridblock and every time step.

Surfactant effect on IFT and subsequently on residual saturations is incorporated by a dimensionless group, *trapping number*, which is a combination of capillary number and Bond number as expressed below to model the effect of capillary, gravity and viscous forces at the pore-scale in three dimensions (Delshad, 1994):

$$N_{T\ell} = \frac{|\vec{K} \cdot \vec{\Delta} \phi_\ell - \vec{K} \cdot [g(\rho_\ell - \rho_e) \vec{\Delta} h]|}{\sigma_{\ell\ell}}, \quad (6)$$

where $N_{T\ell}$ is dimensionless trapping number, \vec{K} is permeability tensor, ρ_l is phase density, h is vertical depth, and σ is interfacial tension. The imbibition process is first initiated by considering surfactant diffusion into a gridblock; IFT is then reduced with the increase in trapping number (Eq. (6)). The residual oil saturation reduces as trapping number increases, with subsequent changes in endpoint relative permeability, endpoint capillary pressure, and exponents of relative permeability curves.

The effect of mobilization on residual phase saturations is modeled in UTCHEM as follows (Delshad, 1994):

$$S_{\ell r} = S_{\ell r}^{\text{high}} + \frac{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}}{1 + T_\ell N_{T\ell}}, \quad (7)$$

where $S_{\ell r}^{\text{high}}$ and $S_{\ell r}^{\text{low}}$ are residual saturations for phase- ℓ at high and low trapping numbers, respectively, T_ℓ is the trapping parameter for phase ℓ assigned as input and $N_{T\ell}$ is trapping number of phase ℓ . The effect of mobilization on endpoint relative permeabilities is modeled as follows:

$$k_{r\ell}^o = k_{r\ell}^{\text{high}} + \frac{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}}{S_{\ell r}^{\text{low}} - S_{\ell r}^{\text{high}}} (k_{r\ell}^{\text{high}} - k_{r\ell}^{\text{low}}), \quad (8)$$

where $k_{r\ell}^{\text{high}}$ and $k_{r\ell}^{\text{low}}$ are phase ℓ endpoint relative permeabilities at high and low trapping numbers, respectively, $S_{\ell r}^{\text{low}}$ corresponds to residual saturation of the conjugate phase ℓ , and $S_{\ell r}^{\text{low}}$ and $S_{\ell r}^{\text{high}}$ are residual saturations at low and high trapping numbers, respectively.

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