Investigation of Pore Structure Impact on the Mobilization of Trapped Oil by Surfactant Injection.

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ABSTRACT

We report an experimental investigation on the effect of flooding parameters, fluid interfacial properties and rock structure on the CDC and on the water relative permeability. Experiments were performed on a set of water-wet sandstones with different petrophysical properties. CT-scan imaging was used to accurately measure the mean residual oil saturation at the macro plug scale. Oil ganglia size distribution as well as pore scale geometrical properties were quantified using high resolution micro-CT images. Results showed that the CDC depends on the pore structure; however rescaling using the relative permeability allows the curves to collapse. We show that for intermediate trapping numbers, a strong dependence of the water relative permeability on the latter can be noticed. Finally, we propose a new method to predict CDC based on structural properties determined experimentally by micro-CT.

INTRODUCTION

The evolution of the residual oil saturation as a function of the trapping number N_t (capillary number plus Bond number), is generally known as the Capillary Desaturation Curve (CDC) and constitutes an important input parameter in chemical EOR flooding. However, less importance has been paid to the investigation of the influence of oil ganglia mobilization on relative permeabilities.

A first attempt to predict CDC from structural parameters have been proposed by Stegemeier [1] and Zhou and Stenby [2]. They have calculated CDC using pore throat radii distribution and a correlation function defining the amount of trapped oil. A good estimation of experimental CDC was obtained. However, these approaches use a correlation function that is not trivial to obtain. Yet these pioneer works show the dependency of CDCs on two main structural parameters: the throat size distribution and the trapped cluster size, which impacts the accessibility path of the flooding fluid. In [3] authors have measured the CDC and end point relative permeabilities for a set of water wet sandstones using surfactant flooding. They have shown the dependency of the CDC on the relative permeability as well as ganglia size. In order to obtain information on the dependence of the pressure- flow rate relation on the capillary number, Sinha et al. [4], Tallakstad et al. [5] and

Yiotis et al. [6] investigated steady state immiscible two-phase flow. They observed the existence of three regimes, when expressing the normalized pressure gradient as a function of the capillary number. In the present work we first provide information on the dependency of the pressure gradient on the trapping number and discuss the water relative permeability scaling. Then we introduce a new scaling group based on water permeability and measured pore scale geometrical properties to propose a single curve for the different CDC.

Material and methods

Experiments were performed on highly consolidated water-wet, clean Berea, Bentheimer, Fontainebleau and Clashach sandstones cores. Coreflood experiments were combined with CT-scan imaging to accurately measure the mean residual oil saturation. Samples were first saturated with brine and drained by n-Decane injection. Then, we displaced the oil by injecting brine (or a mixture of brine and surfactant) at different capillary numbers and the pressure between the inlet and outlet was continuously measured. Mini-plugs (5,6 mm in diameter) were also submitted to drainage under n-Decane followed by a free spontaneous imbibition. Samples were then imaged by a mico-CT at dry and residual oil saturation conditions with 3 µm resolution. More details on experimental procedure and sample properties can be found in [3].

DISCUSSION

Scaling of the water relative permeability

For all samples three regimes can clearly be distinguished all following $\Delta P^{*} \approx N_t^{\beta}$ (cf. Figure 1) where ΔP^{*} is the pressure gradient normalized by $\sigma L/K_a$ (σ is the interfacial tension, L the core length and K_a the absolute permeability) and N_t the trapping number. In the first regime, for values of N_t less than N_t^{c1} we observed β=1 (linear Darcy's law). In this regime, oil ganglia are not yet mobilized as the imposed flow rate is too low to overcome capillary forces. Thus, only brine is flowing and the flow type equates to single phase flow in a medium of constant permeability. Once the capillary number is increased beyond the critical value N_t^{c1}, ΔP is now proportional to N_t^{β} with β~0.5 until N_t^{c2}. In our case, the trend can be explained as follows: in the capillary number range $N_t \in [N_t^{c1}; N_t^{c2}]$, a small change in N_t leads to an amount of mobilized ganglions, unblocked paths are now accessible to the brine. As the imposed flow rate is constant and each accessible path contributes quasi linearly to the total flow, the increase in the number of accessible paths leads to an exponent β smaller than one. The third regime is then characterized by β=1, as either no more oil is in the core or as the increase in N_t mobilizes only few ganglia and the number of new accessible paths is negligible. In this regime flow follows again the classical, linear Darcy's law. Thus, we can conclude that the pressure-capillary number relation during ganglia evacuation is similar to the one of steady state immiscible two-phase flow.

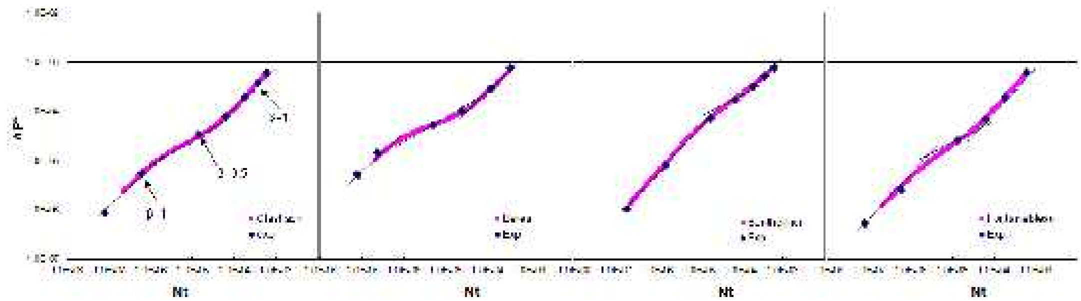


Figure 1: Different flow regimes observed when plotting the normalized pressure gradient as a function of N_t

CDC scaling group

We have investigated the correlation between the effective brine permeability ($K_a K_{rw}$), porous structure, the equivalent oil blobs mean radius (R_b) (corresponding to the radius of the sphere of a same volume (V_b)) and capillary desaturation curve. Micro-CT images (cf.Figure 2 (a)) showed clearly differences in pore structure between the four sandstones leading to a different blob size distribution. At the pore scale represented by the scheme in Figure 2(b) the minimum pressure drop (ΔP_{min}) required to mobilize the oil blob is equal to the capillary pressure given by:

$$\Delta P_{\min} = P_{w1} - P_{w2} - \rho_o g(2R_b) = 2\sigma\cos\theta\left(\frac{1}{r_p} - \frac{1}{R}\right) \ldots(1)$$

where θ is the contact angle, ρ_o represents the oil density, g the gravity acceleration, R the pore radius and r_p the blocking pore throat radius. Darcy's law is expressed by:

$$V = -\frac{K_a K_{rw}}{\mu L}(P_{w2} - P_{w1} + \rho_w g(2R_b)) \ldots\ldots\ldots(2)$$

where V, μ and ρ_w are respectively the Darcy velocity, viscosity and density of the displacing fluid. Substituting (P_{w1}-P_{w2}) deduced from equation (1) in equation (2) leads to:

$$\frac{V\mu}{\sigma\cos\theta} + \frac{(\rho_w - \rho_o) g K_a K_{rw}}{\sigma\cos\theta} = \frac{K_a K_{rw}}{R_b}\left(\frac{1}{r_p} - \frac{1}{R}\right) \ldots(3)$$

Using the definition of the trapping number from [3] equation (3) becomes:

$$N_t = \frac{K_a K_{rw}}{R_b}\left(\frac{1}{r_p} - \frac{1}{R}\right) \ldots\ldots\ldots(4)$$

As a consequence and considering $1/r_p >> 1/R$ an oil blob can be mobilized if the following inequality is respected**:**

$$N_t \geq \frac{K_a K_{rw}}{r_p R_b} \ldots\ldots\ldots(5)$$

This equation shows that the trapping number at the threshold of ganglia mobilization is linked to three main parameters: the effective brine permeability (K_aK_{rw}), the throat radius of the trapping pores and the trapped phase size. However, these three parameters are not independent. Indeed, the effective permeability depends on the available path that is controlled at the pore scale by the pore throat radius and the size of the blocking oil cluster. It is also obvious, that during a capillary desaturation process the mean size of the trapped oil cluster changes. Indeed, experimental observations in [7, 8] shows that the mean size of the trapped clusters decreases when the capillary number increases during the capillary desaturation process. Equation (5) can be written as:

$$\frac{N_t}{K_a K_{rw}} \geq \frac{1}{r_p R_b} \qquad (6)$$

Parameters of the left hand side of the latter equation are defined at the macro plug scale whereas parameters of the right hand side are defined at the pore scale (mini plug). We now assume that the aspect ratio (α) between the oil ganglia radius and the corresponding trapping radius is constant ($r_p = R_b/\alpha$) and multiply the two sides of equation (6) by the square of the mean pore throat radius $< r >^2$. We can then define two equivalent scaling groups :

$$N_t^* = \frac{N_t < r >^2}{K_a K_{rw}} \geq \frac{\alpha < r >^2}{R_b^2} \qquad (7)$$

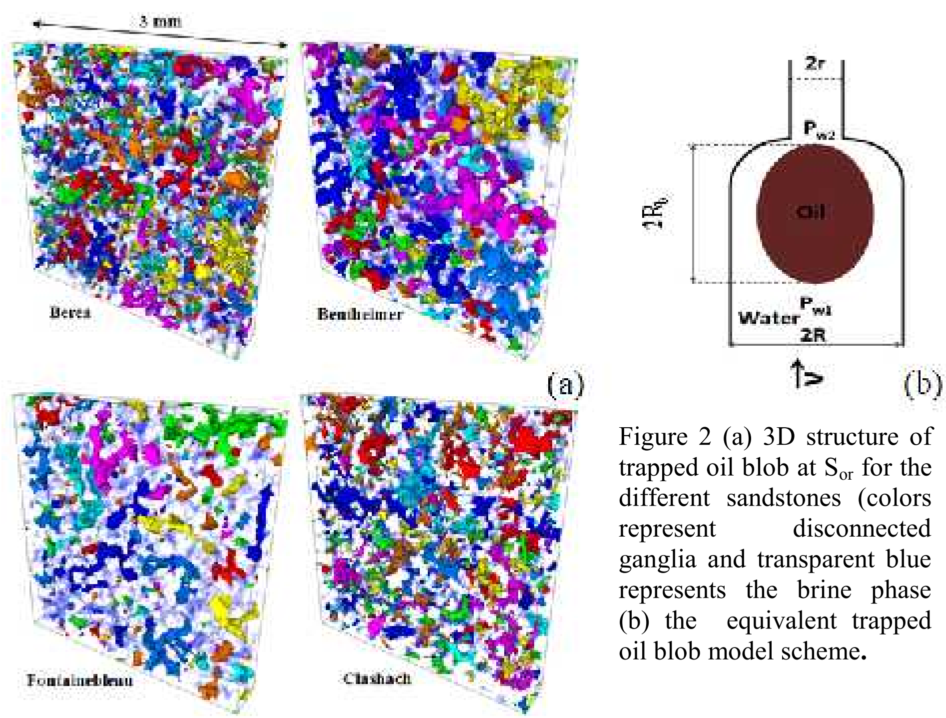


Figure 2 (a) 3D structure of trapped oil blob at S_{or} for the different sandstones (colors represent disconnected ganglia and transparent blue represents the brine phase (b) the equivalent trapped oil blob model scheme.

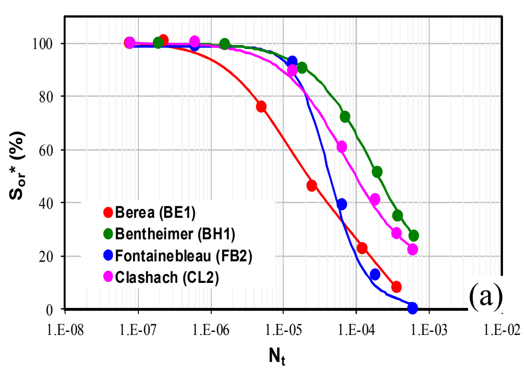
Figure 3 shows the CDC curve obtained on macro plug and plotted in as a function of the unmodified trapping number in (a) and as a function of the reduced trapping number in (b). Using this new scaling group the four CDC quasi superimposed with a critical capillary number around $N_t^*=10^{-2}$ and a total desaturation at $N_t^*=1$.

According to equation (7) we can consider that after flooding at a given reduced trapping number N_t^* corresponding to a given R_b all the ganglia with a size greater then R_b are removed. At this trapping number the normalized residual oil saturation $S_{or}^*(N_t^*)$ in the mini plug can be expressed as:

$$S_{or}^*(N_t^*) = \frac{4\pi}{3V_{ori}} \sum_{R_{bi} \le R_b} R_{bi}^3 f(R_b = R_{bi}) \quad \ldots\ldots\ldots\ldots(8)$$

where R_{bi} is the i[th] class size of ganglion radius distribution function $f(R_b)$ and V_{ori} is the total volume of oil in the mini plug after spontaneous imbibition. One can notice that the function $S_{or}^*(N_t^*)$ is the volume weighted cumulative distribution function of the ganglion size. In Figure 4 we plot S_{or}^* obtained on macro plugs as a function of $\frac{N_t < r >^2}{K_a K_{rw}}$ and S_{or}^* obtained by equation (8) as a function of $\frac{\alpha < r >^2}{R_b^2}$ which correspond respectively to the CDC at the macro and mini plug scale.

The average aspect ratio α is computed from the ratio between initial $<R_b>$ (computed from the initial residual oil saturation (S_{ori}) distribution) and $< r >$, with the assumption that at S_{ori} $< r > \sim < r_p >$. It is to be noted that $< r_p >$ cannot be obtained easily from the micro-CT images as the flow direction is not known. From these curves we can see that the CDC defined at the two different scales match very well for all samples. These results show that CDC can be estimated using structural parameters and that ganglion size distribution is a first order parameter.



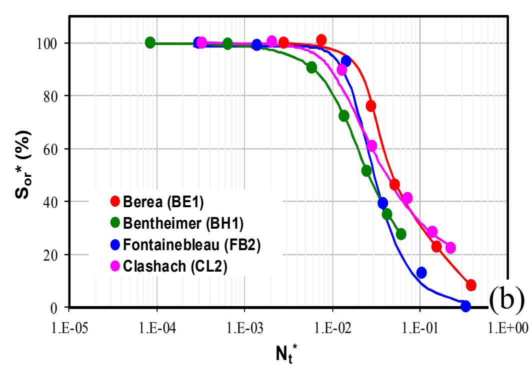


Figure 3 Comparison of capillary desaturation curves plotted using in (a) S_{or}^* vs N_t and in (b) S_{or}^* vs N_t^*. Data are collected on the macro plug experiments for the four sandstones (S_{or}^* is the residual oil saturation normalized by the residual oil saturation after the first waterflood, see [3] for the experimental details).

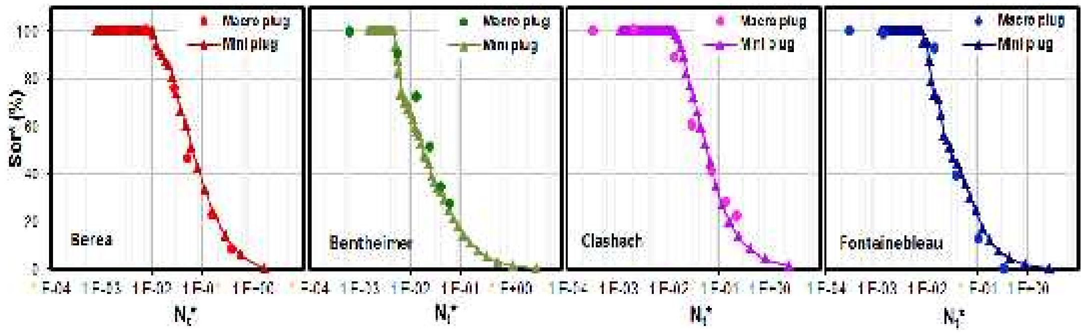


Figure 4: Capillary desaturation curves as a function of the modified trapping number (from macro plug experiments (points) and from mini plug image properties computed at Sor (triangles).

CONCLUSIONS

In the present work we performed brine and surfactant flooding experiments in Berea, Bentheimer, Fontainebleau and Clashach sandstone in order to investigate the influence of the pore structure on the mobilization of oil ganglia and the resulting relative permeabilities. We observed, that for low and high trapping numbers and for all rock types, the pressure gradient between the inlet and the outlet of the sample scales like $\Delta P \approx N_t^{1}$, whereas it becomes $\Delta P \approx N_t^{0.5}$ for the intermediate trapping number range. A modified trapping number was introduced, that takes into account effective brine permeability, or in other words, the size of the effective pathways through which fluid flow occurs. Use of the modified trapping number permits rescaling CDC on quasi unique curve. Finally we have introduced a pore scale method to predict CDC based on image statistics at S_{or}.

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