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Numerical Evaluation of the Combined Effect of Wettability and Heterogeneity on Waterflood Performance.

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Abstract

Laboratory experiments have shown that wettability affects fluid distribution at the pore scale and therefore has an important effect on the end-point saturations and the shapes of capillary pressure (Pc) and relative permeability (Kr) curves. At reservoir scale, the combined effect of wettability and permeability heterogeneity is not so clear. The purpose of the paper is to quantify the effect due to an uncertainty on wettability on oil recovery. Breakthrough times and fraction of recoverable oil during waterflood were numerically studied on a simple 2-dimensional reservoir with 3 and 5 facies of different permeabilities and uniform wettability ranging from oil-wet to water-wet conditions. At intermediate flow rate (0.3 m/day) we observe:

- from intermediate to water-wet wettabilities final recovery is always near 1, recovery decreasing with an increase of the wettability index WI. The correlation length. shows no significant effect.
- for oil-wet reservoirs, final recovery is about 30% less. In addition, there is a strong effect of heterogeneity: the best recovery occurs for layered reservoirs.

At higher flow rates, capillary effects are comparatively reduced and the effect of wettability on recovery becomes less important.

Introduction

In reservoir engineering little attention has been paid to the combined effects of wettability and permeability heterogeneity on oil recovery. While much literature has been devoted to effects at the core scale, very few studies have quantified the effects of wettability at the reservoir scale.

Wettability affects both end-point saturations and the shape of the capillary pressure curve Pc. For instance, it has been shown that intermediate wettability leads to minimum value for Sor (Jadhunandan and Morrow, 1991), thus at large scale inducing a higher recovery. Wettability also changes the shape of the Pc curve. The shape of a Pc curve is characterized by its curvature dPc/dS and its "level", i.e. the relative magnitude of positive and negative values (Fig. 1). The curvature alone is controlled mainly by the pore size distribution and is not function of wettability, yet the "level" of Pc depends strongly on wettability: Pc>0 for water-wet systems and Pc<0 for oil-wet systems (Fig. 1). Thus we can define a wettability index WI as the logarithm of the ratio A2/A1 of the area under the positive to the negative parts of the Pc curve (Fig. 2).

It is to be noted that the combined effects of wettability index (corresponding to a translation of the Pc curve along the Y axis) and heterogeneity can be predicted for strongly heterogeneous media, such as oil-wet fractured reservoirs, where displacement is controlled by spontaneous imbibition, therefore showing no significant oil recovery.

For intermediate cases of permeability heterogeneity, very few results exist in the literature. As early as 1941, Buckley and Leverett recognized that wettability, permeability and water injection rate combine to affect oil recovery. Furthermore, they pointed out that the magnitude of these effects depend on the textural properties of the sand as well as the oil viscosity. Some researchers studied the capillary cross-flow influence on oil recovery using simulation techniques. Goddin, *et al*. studied capillary cross-flow effects using a water-wet 2-layer system with two different capillary pressure curves. They concluded that the maximum capillary cross-flow occurs in the vicinity of the flood front. Fitzmorris *et al*., 1992, reached similar conclusions based on a model using several Pc curves and only one Kr data-set. Their results showed that capillary cross-flow was favorable for a water-wet system while unfavorable for an oil-wet one. On the other hand Kiriakidis *et al*. studied the wettability heterogeneity effect on oil recovery on a microscopic network porous media, using a percolation method. They reached to the conclusion that this type of heterogeneity does indeed have an influence on the recovery. Namba *et al*., 1995, introduced the concept of capillary force barrier, based on unfavorable capillary cross-flow effects observed for an oil-wet system. Observations of water encroachments were reproduced by using negative capillary pressure curves (oil-wet), which were measured by a centrifuge technique.

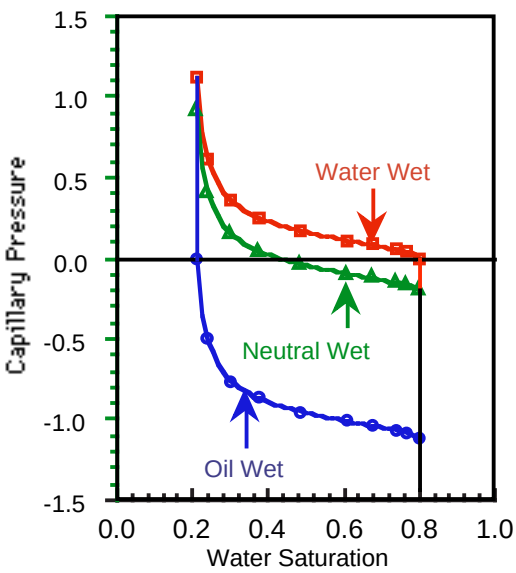

Fig.1 Pc curves for various wettabilities. dPc/dS is the same but the "level" varies, from positive to negative values.

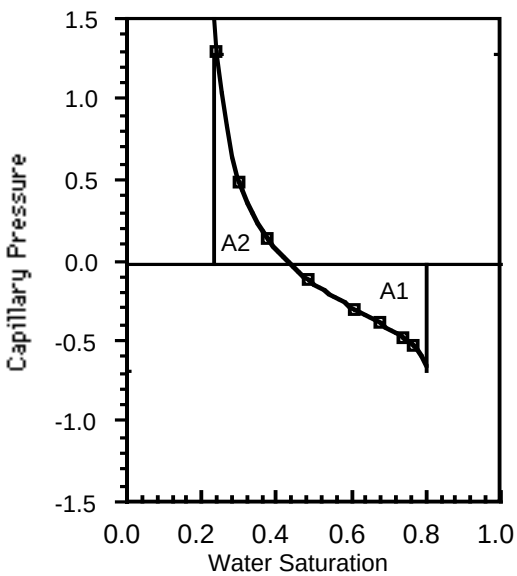

Fig.2 Definition of the wettability index, WI, as Ln(A2/A1).

As seen, not many studies were performed at reservoir scale, nor an evaluation of the effects on recovery due to the uncertainty related to such parameters as the Pc. On the other hand, it has been shown that local variation in relative permeabilities have no effect on large scale recovery (Tjolsen *et al*.) The purpose of this paper was to quantify the recovery uncertainty linked to an uncertainty on the wettability index. While Kr curves are usually available (or derived by indirect means), the derivation of representative Pc curves remains uncertain. Generally, the pore size distribution is inferred from mercury injection but there is no information concerning wettability of the core. Combine effects of wettability uncertainty is studied as a function of correlation lengths and injection rates using numerical simulations in a 2D multifacies model.

Numerical simulations

Simulations were performed under waterflooding conditions using a standard reservoir simulator **ATHOS**, developed by IFP and its subsidiaries. The reservoir consists in a rectangular two dimensional vertical cross-section with two vertical wells at each end. The different permeability fields were generated using **HERESIM**, also developped by IFP, which is an integrated model for reservoir description, using stochastic methods to obtain permeability and porosity maps. Two cases were studied using the same dimensions (x=100 m, y=50 m, z=20 m): Model A (1000 cells) and Model B (20000 cells). For Model A, 3 facies were used whereas for Model B it was 5 with uniform vertical proportions across the field (Table 1).

Table 1 - Proportion and horizontal permeability for models A and B

Facies	1	2	3	4	5
Kx (md)	10	50	100	500	1000
A (1000 grids) %	30	-	40	-	30
B (20000 grids) %	10	20	40	20	10

For both models the correlation length CL in the vertical direction was kept constant at 1.0 m and 0.5, 10, 50, 100, 1000 m. in the x direction. The vertical permeability, Kz was kept at 1/10 of the horizontal one, Kx. For all simulations, the end-point saturations were kept constant at values Swi=Sor=0.2. Relative permeability curves are the same for all facies. They are generated using the Corey function with exponents 2 and end-points values equal to unity.
As explained above, wettability changes were achieved through a shifting technique of the Pc curves. This technique is shown in Figure 1 along with the actual Pc curves. When the area A1 (integration of the negative Pc curve with respect to Sw) is equal to A2 (integration of the positive Pc with respect to Sw), the system is neutral-wet. The reference water-wet capillary pressure curve was chosen to be that of the 1000 md rock and was calculated using the following equation: $Pc=P_{ref}\,[(1 - Sw^*)/Sw^*)^{1/2}$ where Sw*=(Sw-Swi)/(1-Sor-Swi) and P_{ref} = 0.16. For all the other permeabilities, Pc curves were obtained using the classical J-function curve. The J function is the sum of a function J1(S) which accounts for the pore size distribution (scaling with $K^{1/2}$) and that of a constant J0 related to the USBM wettability index WI (J0>0 for water-wet reservoirs). For a given simulation, the wettability index of all facies is the same.
All simulations were performed at a mobility ratio, M = 1.0 with gravity effects ($\Delta\rho$= 150 Kg/m^3). Initial water saturation is 0.2 and all simulations were performed at constant flow rates (corresponding to front velocities of 3,0.3 and 0.03 m/day).
It is generally useful to characterize the displacements by dimentionless numbers. However, there is no universal definition of the magnitude of capillary forces for heterogeneous reservoirs of intermediate wettability. We have chosen the following procedure. First, an average capillary pressure curve <Pc(S)> for the reservoir is calculated assuming pressure equilibrium (Ahmadi *et al.*). Then we define an average capillary pressure Pc* by

$$Pc^*(1 - Swi - Sor) = \int ABS(< Pc(S) >)dS$$

The absolute value avoids a null value for intermediate wettability (WI=0). For Model B, Pc*=1.08 for WI=1 and 4.02 for WI=-1
The capillary number Nc is defined as the ratio of the average capillary pressure Pc* to viscous pressure drop (for one-phase flow). The gravity number Ng is the ratio of gravity forces across the reservoir to viscous ones (one-phase flow). Viscous pressure drop is 7.5, 8.3 and 12.1 bar respectively for the 1000, 100 and 10 CL fields and for front velocity V=0.3 m/day. The pressure difference due to gravity between top and bottom of reservoir is 0.30 bar .The various values of Nc and Ng are given in table 2 for the 10 and 1000 m. CL reservoirs (Model B).

Table 2 Capillary and Gravity numbers for the various simulations (front velocity V=0.3 m/day)

	Capillary Number		Gravity Number
	WI=1	WI=-1	
CL=10 m	0.09	0.33	0.025
CL=1000 m	0.14	0.54	0.04

Results

Results of the numerical simulations for a waterflood performed at 0.3 m/day are presented in Figures 3 and 4 in terms of oil recovery (fraction of recoverable oil) as a function of time for 5 values of Wettability Index and 3 correlation lengths.

For all the correlation lengths, oil recovery decreases when the medium becomes more oil-wet (Fig. 3, case B). Final recovery (at t=10 PV) is always 100% for water-wet reservoirs and decreases by about 30% for oil-wet with CL=10 m. The same results are presented in Figure 4 (case B), using this time CL as parameter instead of WI. For oil-wet and mixed-wet reservoir, oil recovery increases with the correlation length. Nevertheless, for water-wet reservoirs, there is no effect of the correlation length (Fig. 4). Results are similar for Case A but not presented.

Results due to the effect of flow rate are presented for V(injection) = 3.0 and 0.03 m/day in Figure 5 for Case A alone. For V(injection) = 0.3 m/day, results are similar to Case B (Figures 3 and 4). For both cases, recovery increases when water injection rate increases.

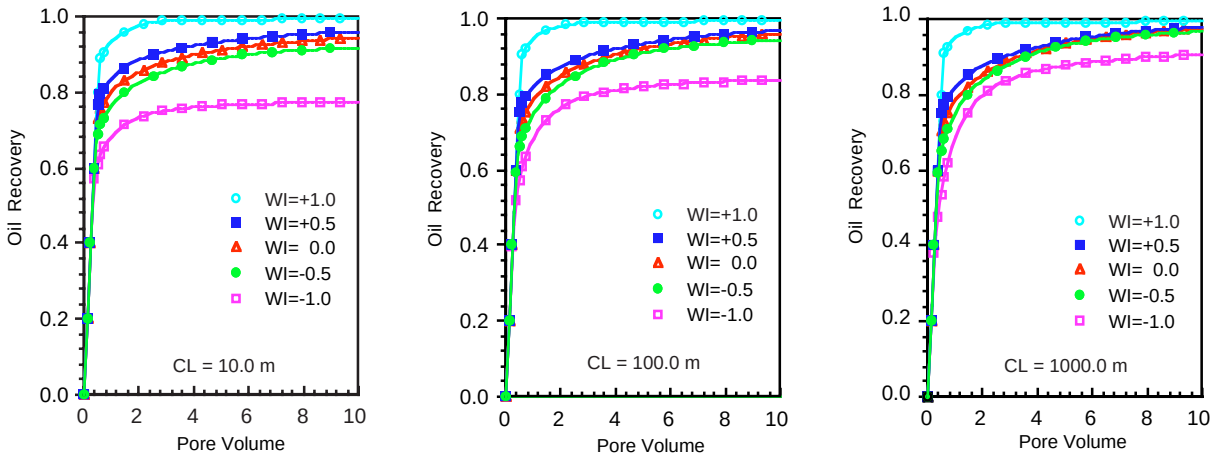

Fig. 3 Effect of wettability and correlation length on oil recovery (case B), Injection velocity = 0.3 m/day.

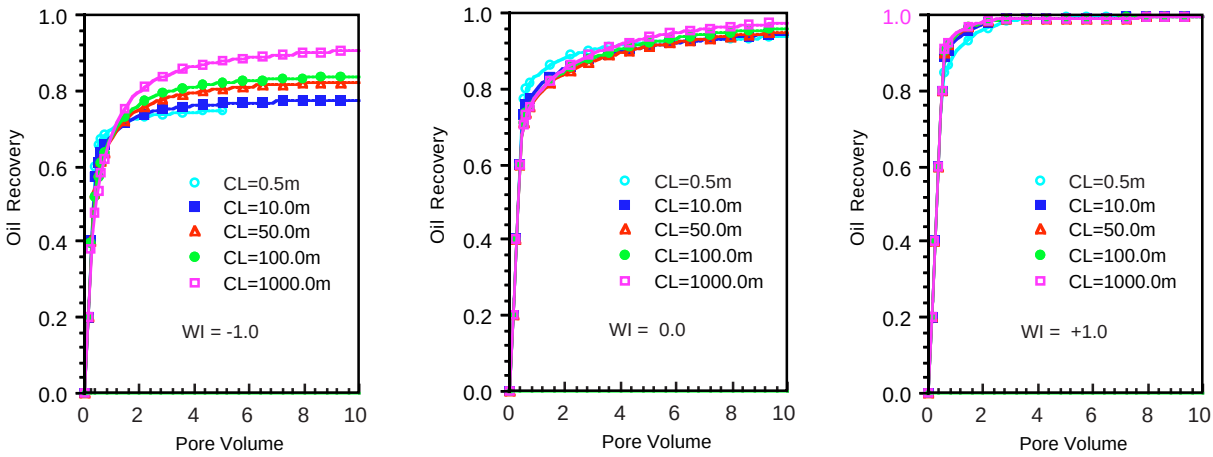

Fig.4 Effect of correlation length on oil recovery at a given wettability. (Case B), injection velocity = 0.3 m/day.

Discussion

The main result is that the effect of wettability change is not negligible at the 100 m scale used for our field simulation. This is not surprising. Effects of capillary pressure on large scale simulation have already been studied (Bu and Haoy, 1995) and the underlying physical mechanisms are well understood.

The effect of flow rate is a consequence of a balance between capillary and viscous forces (if neglecting gravity effects). In steady-state regime, a pressure gradient along the reservoir exists in the water phase while none in oil phase, since this phase is no longer flowing (Fig. 6). Since only water is flowing, pressure in water is always larger than pressure in oil (assuming the same pressure in both fluids at the boundary) and therefore, capillary pressure is negative. Consequently, there is a positive gradient in capillary pressure along the reservoir, with a minimum at the entrance (Fig. 6). The average capillary pressure, Pv* is related to the pressure drop in water, and therefore to the injection rate. The final saturation can be qualitatively deduced from the intersection of the Pc curves of the various facies and the line Pc=Pv*. In Figure 7, we have shown one facies using three different wettabilities. In this example, which could correspond to a low injection rate, final saturation is Sf=0.8 for water-wet and mixed-wet cases, and near 0.2 for the oil-wet case. Increasing the flow rate will decrease the Pv* value, thus increasing the final water saturation Sf. For several facies, there are more than one Pc curve, yet the mechanism is similar. This mechanism explain why recovery is always unity for water-wet cases while increasing with flow rate for mixed and oil-wet cases.

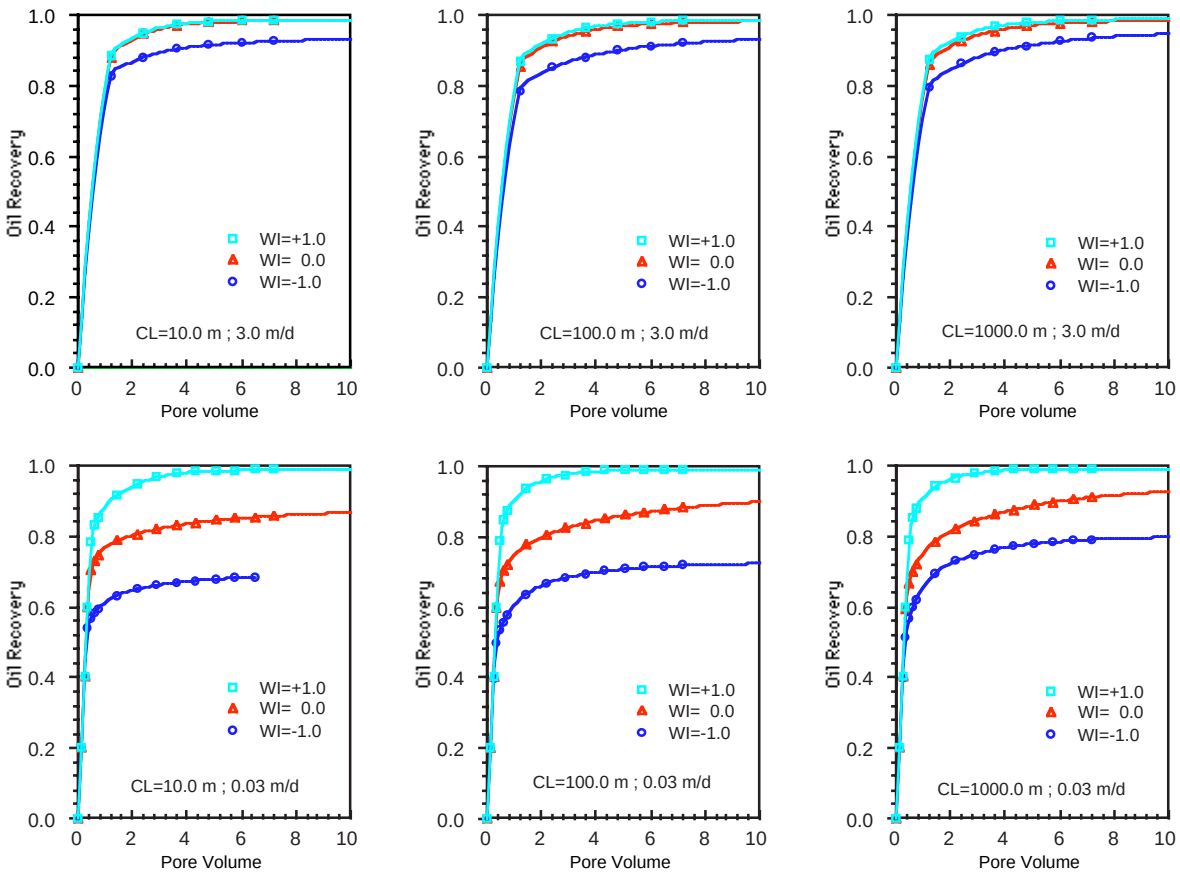

Fig.5 Effect of flow rate on recovery (flooding velocity 3.0 and 0.03 m/d).

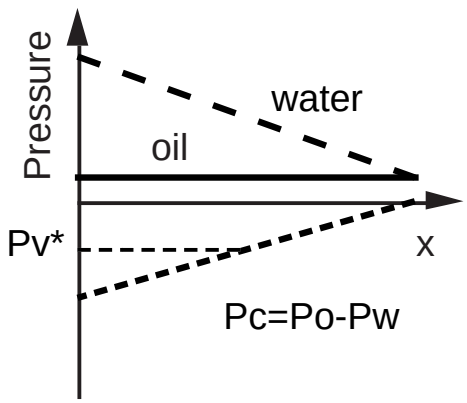

Fig. 6 Schematic of the pressures along the reservoir during steady-state waterflood

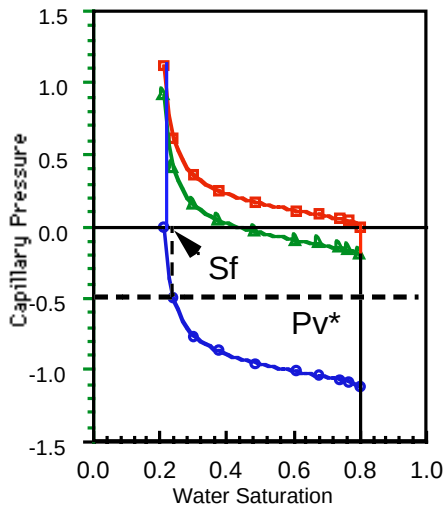

Fig. 7 Equilibrium between viscous pressure drop and capillary pressure during steady-state waterflood.

The effect of correlation length is not so easy to interpret. Results show that recovery is best in layered fields. Here, we are facing two opposite effects. First, the one-phase permeability is higher in layered fields than in low CL fields (for instance, for a CL of 10.0 m, K=145.9 md whereas for a CL=1000.0 m, K=235 md). Consequently, for the same flow rate, the viscous

pressure drop is lower and should lead to a lower recovery (as explained in the previous paragraph). The second effect, is the presence of by-passed areas where oil remains trapped. This effect is less important for layered fields and may explain the better recovery.
It is clear that our results cannot be extrapolated to any types of reservoir. We have assumed uniform wettability. Other assumptions could be used, for instance, that low permeability facies remains always water-wet. Results would be different. What seems important to us is that our fine grid simulations show an effect due to wettability heterogeneity. Very often, full Pc curves are not considered in large-scale reservoir simulations and results overestimate recovery since simulations do not account for capillary trapping. Our results have shown that errors of the order of 30% can be made. The consequence of our work is twofold :

1) we need experimental determination of the negative part of the capillary pressure, such as by centrifuge or porous plate method. The negative part is directly related to the fluid/rock interaction ("wettability") and can not be inferred from mercury porosimetry.
2) the up-scaling method used must account for capillary effects. Even if capillary curves are not used at reservoir scale, the "information" concerning capillary trapping related to wettability must be passed on through the pseudo relative permeabilities used.

Conclusion

In reservoir simulation, the Kr curves are generally known but there is an uncertainty on the Pc curves, due to the lack of information on wettability (imbibition curves are generally inferred from mercury porosimetry or drainage curves). We have performed numerical simulations of a waterflood on a simple 2-dimensional reservoir with 3 and 5 facies. Permeability heterogeneity is characterized by its stochastic properties (variance and correlation length). At intermediate flow rate (0.3 m/day):

- from intermediate wettability to water-wet ($0<WI<1$)), final recovery is always near 1, but the kinetics of recovery decreases with an increasing of the WI. There is no effect of correlation length.
- for oil-wet reservoirs, final recovery is about 30% less. A strong effect of heterogeneity: is observed: the best recovery is obtained for layered reservoirs.

At higher flow rates, capillary effects are comparatively reduced and the effect of wettability on recovery become less important.
Finally, the results are interpreted by a simple physical analysis based on the balance between viscous and capillary forces. The main conclusion is that the imbibition Pc curves (positive and negative) must be used in reservoir simulations for a water injection.

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