Pore-scale modeling: Effects of wettability on waterflood oil recovery

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ABSTRACT
We study the effects of wettability on waterflood oil recovery using a capillary-controlled pore-scale network model. We validate the model against experimental data in the literature on mixed-wet Berea sandstone and then apply it to study multiphase flow through four networks extracted from different types of rock: a sand pack, a poorly consolidated sandstone from the Middle East, a granular carbonate and Berea sandstone. We study the effects of initial water saturation, contact angle distribution and oil-wet fraction on recovery. For a uniformly-wet system, where the contact angle everywhere falls within a relatively narrow range, recovery increases as the system becomes less water-wet and reaches a maximum for oil-wet conditions where recovery is approximately constant for average intrinsic contact angles above 100°. As the initial water saturation increases, recovery decreases in water-wet systems whereas in oil-wet systems it initially increases and then decreases. For mixed-wet systems that contain water-wet and oil-wet regions of the pore space, the oil-wet fraction plays a more important role in determining recovery than the contact angle in the oil-wet regions. Optimal recovery occurs when a small fraction of the system is water-wet. Pore structure plays a relatively minor role in the generic behavior, although it does influence the initial saturation for maximum recovery and the magnitude of the recovery. These results are explained in terms of pore-scale displacement mechanisms and fluid configurations.

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1. Introduction

The wetting condition of a reservoir rock plays a significant role in determining transport properties such as capillary pressure, relative permeability and oil recovery. Many experimental investigations on the impact of wettability have been conducted and several excellent review papers are available (Anderson, 1987a,b; Morrow, 1990; Jadhunandan, 1990). The wettability of a crude oil/brine/rock system can only be determined by indirect measurements of macroscopic behavior, such as the imbibition of water and oil in an Amott test; the fluid distribution and wetting state at the pore scale is not known with certainty. Network modeling, where displacement is simulated through a lattice of pores connected by throats, does make predictions of the microscopic fluid distribution and relates this to macroscopic parameters, such as wettability index and oil recovery (Blunt and King, 1991; Blunt, 1998; Ören et al., 1998; Dixit et al., 1999, 2000; Al-Futaisi and Patzek, 2003; Ören and Bakke, 2003) and hence is a useful tool for understanding the impact of rock structure and wettability on multiphase flow.

Kovscek et al. (1993) proposed a theoretical model for wettability alteration after primary drainage where areas of the pore space in direct contact with oil changed their oil/water contact angle for waterflooding, while water-filled regions remained water-wet. This model has been applied in network modeling to explore the effects of wettability on relative permeability and waterflood oil recovery (Blunt, 1998; Ören et al., 1998; Dixit et al., 1999, 2000). There are two distinct types of wettability. The first is what we describe as uniformly-wet, where all the pores and throats have approximately the same contact angle, within some relatively narrow range; the wettability varies from water-wet (contact angle less than 90°) to neutrally-wet (contact angles close to 90°) to oil-wet (contact angles greater than 90°). The second type is mixed-wettability (Salathiel, 1973) where some pores and throats are water-wet while others are oil-wet. Here the wettability is controlled principally by the fraction of the pores that are oil-wet.

McDougall and Sorbie (1995, 1997) investigated trends in relative permeability and recovery efficiency with a regular cubic network. Recovery was shown to be maximum in a network where half the pore space was oil-wet. McDougall et al. (1996) and Dixit et al. (1999) used the same network structure and introduced the regime theory of wettability classification and analysis, with which they explained experimental trends in waterflood oil recovery in terms of wettability characterized by the oil-wet fraction of pores and contact angle distributions. Al-Futaisi and Patzek (2003) studied the impact of wettability alteration on two-phase flow characteristics with a network extracted from a sample of Bentheimer sandstone. They showed that as the system became less water-wet, the residual oil

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saturation initially decreased but increased dramatically at the transition from water- to oil-wet conditions and then decreased to a minimum in oil-wet systems.

Jadhunandan and Morrow (1995) investigated the relationship between wettability and waterflood oil recovery in a series of Berea cores. They used crude oil as a wettability-altering agent. By varying the initial water saturation $S_w$ and aging conditions, they reproduced different mixed-wet systems representing a range of reservoir conditions. Their study showed that oil recovery by waterflooding initially increased and then decreased as the wettability changed from strongly water-wet to oil-wet, with maximum recovery observed at weakly water-wet conditions. To model this behavior, Bakke and Øren (1997) and Øren et al. (1998) constructed a geologically realistic network of Berea sandstone. Using this network, Jackson et al. (2003) predicted the recovery trend as a function of wettability. They assumed that all oil-invaded pores after primary oil flooding become oil-wet and then matched the experimental wettability indices by varying the contact angle distribution. Øren and Bakke (2003) proposed a method for estimating the oil-wet fraction and contact angle distributions from experimentally measured Amott water and oil indices. With their model, they obtained a quantitative match with the experimental recoveries. Valvatne and Blunt (2004) studied the combination of representative networks with an improved understanding of pore-scale physics allows the successful reproduction of experimental results. However, most studies have been performed on either cubic networks or on a relatively homogeneous network representing just one sandstone — Berea. Micro-CT scanning (Arns et al., 2003, 2004) has enabled the pore structure of a wide range of rock samples to be determined. In this paper we will extend previous studies to investigate the effects of wettability using networks derived from micro-CT images of different rock types.

The paper is organized as follows. In Section 2, we will reproduce the experimental results from Jadhunandan and Morrow. The pore-scale model used to simulate flooding cycles will be briefly introduced and validated. We then select four networks, each of which represents a different rock system. The effects of wettability, initial water saturation, and oil-wet fraction on waterflood oil recovery in different rock systems are systematically studied. The results from uniformly- and mixed-wet systems will be presented in Section 3 and Section 4 respectively. In the last section, we conclude our work.

2. Comparison with experiment

As mentioned above, Jadhunandan and Morrow (1995) conducted a systematic experimental study of waterflood recovery in Berea sandstone. The flow rate was sufficiently low to reproduce capillary-dominated conditions (capillary numbers were $10^{-6}$ and lower). A series of rock samples were initially filled with water and then flooded with crude oil to some initial water saturation $S_w$, between 0.079 and 0.32. All the cores were aged to alter their wettability states, and then waterflooded until 20 pore volumes had been injected. The wetting states of the cores are determined by the Amott test (Amott, 1959) which combines both spontaneous imbibition and forced displacement. The Amott index for each phase $p$ is given by

$$I_p = \frac{\Delta S_p}{\Delta S_{ps} + \Delta S_{pf}}$$

where $\Delta S_p$ and $\Delta S_{ps}$ are the saturation changes contributed by spontaneous imbibition and forced displacement respectively. The Amott water index $I_w$ and Amott oil index $I_o$ are combined to give the Amott–Harvey index $I_{w-o} = I_w - I_o$, which varies between +1 (strongly water-wet) and -1 (strongly oil-wet).

We now use pore-scale network modeling to reproduce the experiments and see whether the same trend and results could be predicted. We use a similar methodology to that presented by Valvatne and Blunt (2004). We use Øren et al’s geologically realistic Berea network as the input to a two-phase simulation code (Valvatne and Blunt, 2004). Contact angle hysteresis is included by adopting Morrow’s experimental results (Morrow, 1975), which relate the receding and advancing contact angles to the intrinsic contact angle. The network properties are listed in Table 1 and presented in Fig. 1. We assume capillary-controlled displacement meaning that there is no effect of flow rate on the results.

All systems are assumed to have the same connate water saturation 0.079, the minimum value achieved in experiments. Fluid properties are consistent with their experimental values. Water and oil viscosities are 0.99 and 5.23 mPa s respectively and the interfacial tension is 12 mN/m. The network is initially water saturated and then oil flooded to the experimentally measured $S_w$. During this primary oil flooding, the receding contact angles are assumed to be 0°. Water is then injected to displace oil and in this flooding cycle, the intrinsic contact angles for water-wet pores are between 50° and 60°. We adjust the oil-wet fraction of the network to match $I_{w-o}$, to match $I_o$ we keep the lower bound of intrinsic contact angle in the oil-wet fraction at 80° and adjust the upper bound. During secondary water flooding, water and oil relative permeabilities are calculated and used to predict oil recoveries using Buckley–Leverett analysis.

Our predictions are illustrated in Fig. 2. Both the experimental and predicted maximum recoveries occur at nearly neutrally-wet conditions although our prediction is shifted to more oil-wet conditions.

3. Effects of wettability on waterflood oil recovery

3.1. Network preparation

We have built up a library of images of sand packs, sandstones and carbonates obtained using micro-CT scanning (Dong and Blunt, 2009). A maximal ball algorithm (Silin et al., 2003; Patzek and Silin, 2006; Al-Kharusi and Blunt, 2007; Dong and Blunt, 2009) is used to extract topologically equivalent networks of pores and throats from the selected target area of the images. We select networks S, F and C from three different rock systems. S is a poorly consolidated sandstone from an Arabian oilfield. It mainly consists of quartz grains, which show a bimodal grain-size distribution, and some poikilotopic cements. Sand pack F is made from quartz sand, which is unground silica provided by US Silica Company. The grains are well sorted and the average size is 0.29 mm. Carbonate C is a typical calcrite or lithified paleosol, enclosing carbonate elastic detritus and rhizoliths (calcified root tubules). Further analysis of its thin-section images suggests it probably developed as a weathering ring of limestones during exposure (uplift or sea-level drop). Fig. 3 shows 2-D sections of the micro-CT images from samples S, F, C and their extracted networks.

The average properties of the three networks are listed in Table 1 while pore size, throat size, aspect ratio and coordination number distributions are presented in Fig. 1. Three important features about the pore structures of different rock systems should be noted. First, C has much wider pore and throat size distributions than Berea and S while most parts of its pore space are smaller. Diagenesis and structural changes play key roles in determining the carbonate’s pore space after sedimentation, while compaction and cementation dominate the pore space development for the sandstones studied. In this example, which is typical of carbonates, complex diagenetic processes lead to a wide distribution of pore sizes with many very small elements. Second, while a small fraction of pores in C have
Table 1
Network properties for different rock systems. $\phi$, $K$, $r_p$, $r_t$ refer to porosity, permeability, pore and throat radius respectively. The coordination number is number of throats connected to each pore. The aspect ratio is the average ratio of the pore radius to the average radius of its connected throats.

<table>
<thead>
<tr>
<th>Network</th>
<th>Rock type</th>
<th>Network size/mm</th>
<th>Pores</th>
<th>throats</th>
<th>$\phi$</th>
<th>$K$/d</th>
<th>Ave. $r_p$/(\mu)m</th>
<th>Ave. $r_t$/(\mu)m</th>
<th>Ave. coord. no.</th>
<th>Aspect ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Berea</td>
<td>Sandstone</td>
<td>3</td>
<td>12,349</td>
<td>26,146</td>
<td>0.183</td>
<td>3230</td>
<td>19.2</td>
<td>11</td>
<td>4.2</td>
<td>2.1</td>
</tr>
<tr>
<td>S</td>
<td>Sandstone</td>
<td>2.73</td>
<td>8532</td>
<td>15,105</td>
<td>0.168</td>
<td>301</td>
<td>16.7</td>
<td>7.5</td>
<td>3.5</td>
<td>2.7</td>
</tr>
<tr>
<td>F</td>
<td>Sand pack</td>
<td>3</td>
<td>1000</td>
<td>2856</td>
<td>0.328</td>
<td>77,613</td>
<td>44.7</td>
<td>27.9</td>
<td>5.5</td>
<td>2.1</td>
</tr>
<tr>
<td>C</td>
<td>Carbonate</td>
<td>2.138</td>
<td>6718</td>
<td>10,336</td>
<td>0.168</td>
<td>134</td>
<td>11.4</td>
<td>6.2</td>
<td>3</td>
<td>2.9</td>
</tr>
</tbody>
</table>

quite large coordination number, it is more remarkable that there are many of dead-end pores, which can act as fluid storage space but which are not effective fluid transport paths. Third, the sand pack F, as expected, has large pores and throats since the medium is composed of relatively large grains that remain unconsolidated. The sandstone S tends to have higher aspect ratios (ratio of pore to throat size) than Berea, which is surprising, since it is poorly consolidated; however this is related to the wide range of grain size, apparent in Fig. 3.

We perform water–oil flow simulations on these four networks to study the effects of wettability. The results are presented in the following two subsections. Water and oil physical properties are the same as those used when we reproduced the experimental results in the previous section and three pore volumes of water are injected to predict waterflood oil recovery using Buckley–Leverett theory based on the computed relative permeabilities.

3.2. Effects of wettability in uniformly-wet systems

For each network model, we displace the initially water-filled system by oil to a pre-determined water saturation $S_{wi}$. In the model we assume that water can remain connected down to zero saturation — we do not allow for a genuinely irreducible saturation due to clays or disconnected water. During this primary oil flooding, the receding contact angle is set to 0 everywhere. During secondary water flooding, we adjust the intrinsic contact angles to obtain different wettabillities indicated by the Amott–Harvey Index $I_{w-o}$. The intrinsic contact angles are randomly distributed to pores and throats in the network. For each system, they follow a uniform distribution with a range of 20°. By adjusting the average of the intrinsic contact angle interval, we can obtain different wetting systems from strongly water-wet to oil-wet. Fig. 4 illustrates the correlation between $I_{w-o}$ and the average intrinsic contact angle $\theta$. As $\theta$ increases, the wetting state changes from water-wet ($I_{w-o}>0$, $\theta<80°$) to oil-wet ($I_{w-o}<0$, $\theta>100°$), with a neutrally-wet plateau where $\theta$ ranges from 80° to 100°. It is also clear that the system becomes slightly more water-wet as $S_{wi}$ increases.

The predicted recoveries as a function of $I_{w-o}$ for the different networks are presented in Fig. 5.

3.2.1. Effects of wettability

These results indicate that oil recovery increases as the system becomes less water-wet. When the system is weakly water-wet, oil recovery improves dramatically as $I_{w-o}$ decreases towards neutral wettability ($80°<\theta<100°$). The maximum recovery occurs for oil-wet conditions ($\theta>100°$), where recovery becomes a constant function of $I_{w-o}$. In Fig. 6 we present the relative permeabilities, fractional flows and recovery curves as a function of wettability for one example case: network F with an $S_{wi}$ of 0.05.

Water relative permeability and residual oil saturation increase with $I_{w-o}$. The trend in residual saturation has been discussed by several authors previously (McDougall and Sorbie, 1995; Blunt, 1997, 1998). After primary oil flooding, oil occupies the centers of large

Fig. 1. Network static property distributions.
pores and throats while their corners and smaller elements are still filled with water. In strongly water-wet media, water can flow readily through the wetting layers in the corners of the pore space, preferentially filling the narrowest elements by snap-off. Oil is stranded in the larger pores. As the contact angle increases, snap-off is less favored in comparison with piston-like advance of water into oil, which leads to a connected front and less trapping. When the medium becomes oil-wet, oil remains connected in layers sandwiched between water in the corners and water — as the non-wetting phase — in the centers of the pores. These layers maintain continuity of the oil down to very low saturations.

The trend in water relative permeability is counter-intuitive, however. As the system becomes more oil-wet, water preferentially invades the larger pore spaces which have the greatest conductance to flow. Hence, at a given water saturation one would expect the water relative permeability to increase as the system becomes more oil-wet; instead we see the opposite — although larger values of the water relative permeability are reached in oil-wet media, this is only at high water saturations. The reason for this behavior is that the water remains poorly connected through the pore space at low and intermediate water saturation. In a water-wet medium, a connected pathway of smaller elements across the system is established at lower water saturations than when the larger elements (that have more volume) are filled. It is only when there is a connected path of water-filled pores and throats in the larger elements — at high water saturations — that the water relative permeability is large and increasing steeply with saturation in oil-wet media.

Similarly the oil relative permeability increases as the system becomes more oil-wet; again this is at first sight the opposite of what would be expected. The explanation rests on the connectivity of the oil phase. In a water-wet system, the filling of small elements by snap-off effectively disconnects conductive pathways of oil between the larger pores and the oil relative permeability drops rapidly with increasing water saturation. In neutrally-wet media, there is a more connected advance of water and the oil remains better connected. In oil-wet media, oil layers maintain the connectivity of the oil phase even in elements whose centers are water-filled; these layers retain flow paths across pores and throats between oil-filled regions and allow the oil relative permeability to stay relatively high.

The combination of low water relative permeability and residual oil saturation gives the best waterflood recovery for oil-wet media. While this can be explained, it is contrary to the analysis of the experimental data we performed in the previous section, where it appeared that neutrally-wet media gave the best recoveries. Again we have an apparent contradiction whose explanation hinges on the likely typical nature of the distribution of wettability in apparently oil-wet media, which we discuss in the subsequent sections.
Fig. 4. Amott–Harvey index $I_w-o$ as a function of average intrinsic contact angle $\theta$ on different rock systems.

Fig. 5. Recovery as a function of Amott–Harvey index $I_w-o$ on different rock systems (the recovery is computed after three pore volumes of water are injected).
3.2.2. Effects of initial water saturation ($S_{wi}$)

As shown in Fig. 5, the oil recovery decreases with $S_{wi}$ for water-wet systems regardless of rock type. For oil-wet systems, the oil recovery initially increases and then decreases as $S_{wi}$ increases. We plot recovery as a function of $S_{wi}$ in Fig. 7 for different rock types for oil-wet systems ($\theta > 100^\circ$). It is clear that there exists a range of $S_{wi}$ that gives optimal oil recovery and that this range depends on the rock type.

We again choose network F as an example to interpret the predicted results. For both water- and oil-wet conditions, three systems with different initial water saturations are selected. The intrinsic contact angles are [60°, 80°] for water-wet and [105°, 125°] for oil-wet conditions. The effects of $S_{wi}$ on relative permeability are shown in Fig. 8.

As $S_{wi}$ increases, the number of elements initially filled with water as well as the thickness of corner water will increase; therefore, the water conductivity increases, while the oil conductivity, restricted by water blocking flow channels, will decrease. Hence the initial oil relative permeability decreases and the initial water relative permeability increases with $S_{wi}$.

Under water-wet conditions, an increase in $S_{wi}$ leads to more flow in wetting layers and more snap-off and oil trapping, resulting in increasing residual oil saturations and lower recoveries. Note that the water relative permeability is not independent of $S_{wi}$, but increases with increasing $S_{wi}$ since the water is better connected throughout the system. With a low $S_{wi}$ there is less snap-off and piston-like advance needs to fill a large number of elements to establish a connected pathway of water-filled elements, whereas for a larger $S_{wi}$, the water is initially relatively well connected and further filling rapidly adds to the water conductivity (Valvatne and Blunt, 2004).

For oil-wet conditions, the behavior has been described for Berea networks (Valvatne and Blunt, 2004). Piston-like advance is favored and water prefers to fill the large pores and throats by displacement from initially water-filled elements. When $S_{wi}$ is low, there are relatively few of these elements. Therefore, to connect across the system through the centers of the pore space, water has to find a pathway of larger elements. As $S_{wi}$ increases, the number of initially water-filled elements will increase. However, most of these are isolated and only connected to each other through wetting layers. As water preferentially displaces oil in large pores and throats, the water saturation increases while its conductivity changes only very slowly, which results in low $k_{rw}$ and high $k_{ro}$ over a large $S_{wi}$ range. When $S_{wi}$ becomes high, some initially water-filled clusters are more closely connected. Therefore, they can be easily merged by injected water and form high-conductivity flow paths, resulting in a rapid increase in $k_{rw}$. A low water relative permeability gives a macroscopically high advancing shock front and good recovery. Oil recovery is highest for intermediate values of $S_{wi}$, when $S_{wi}$ is very low, the pathway of large elements, once connected, allows $k_{rw}$ to increase rapidly with

![Fig. 6. Influence of wettability on relative permeability, fractional flow and waterflood oil recovery for a sand-pack network, F with $S_{wi} = 0.05$.](image)

![Fig. 7. Recovery after three pore volumes of water injected as a function of initial water saturation under oil-wet conditions ($\theta > 100^\circ$) for different rock types.](image)
saturation, while higher $S_{wi}$ leads to poorer connectivity until $S_{wi}$ is sufficiently large to allow water to be well connected. This trend in recovery has been discussed in the context of waterflooding transition zone reservoirs, where the decrease of $S_{wi}$ with height above the oil/water contact leads to variation in wettability (Jackson et al., 2003).

3.3. Effects of wettability in mixed-wet systems

To simulate mixed-wet conditions, we assign a target volume fraction of oil-filled pores and throats and alter their wettability after primary oil flooding. The intrinsic contact angle for water-wet elements is between 30° and 50°. We keep the lower bound of the intrinsic contact angle distribution for oil-wet elements at 90°, and then adjust both its upper bound and the oil-wet fraction to obtain different wetting conditions. We calculate water and oil relative permeabilities and use Buckley–Leverett analysis to predict oil recoveries. Again, three pore volumes of water are injected to displace oil in the recovery prediction.

The results obtained from our four networks show the same generic features and thus we present the results from Berea here as an example. The effects of oil-wet fraction and wettability on oil recovery are shown in Fig. 9, where each figure represents a mixed-wet system with a different initial water saturation. Oil recovery is approximately a constant function of $I_{w-o}$ for a given oil-wet fraction, since the residual oil saturation remains approximately constant, at a low value, for the oil-wet regions as the contact angle is altered.

However, both $S_{wi}$ and the oil-wet fraction have a significant impact on oil recovery. Initial water saturation gives the same trend in recovery for both uniformly-wet and mixed-wet systems. The effects of oil-wet fraction on relative permeability and water fractional flow are illustrated in Fig. 10 for Berea with an initial water saturation of 0.1. The behavior is similar to that observed with initial water saturation: lowering the oil-wet fraction is equivalent to increasing $S_{wi}$ with the same non-monotonic trend in recovery, with the optimal displacement achieved at some intermediate oil-wet fraction. However, there are two differences between the relative permeability behavior, evident from a comparison of Figs. 8 and 10. First, the oil and water relative permeabilities at the beginning of water flooding are the same regardless of oil-wet fraction, since the initial distribution of water is the same. Second, the residual oil saturation increases as the oil-wet fraction decreases. This is because oil can be trapped by snap-off in the water-wet portions of the pore space.

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Fig. 8. Effects of initial water saturation $S_{wi}$ on relative permeability for a sand pack F: left for water-wet and right for oil-wet conditions.

Fig. 9. Recovery as a function of Amott–Harvey index $I_{w-o}$ at different $S_{wi}$ for Berea sandstone. Fraction represents the fraction of initially oil-filled elements that are oil-wet.
We now combine these results to show oil recovery as a function of oil-wet fraction for all four networks and for different values of $S_{wi}$, see Fig. 11. As we have already discussed, the contact angles in the oil-wet regions have little effect on recovery: in Fig. 11, the oil-wet regions have a contact angle distribution in the range $[90°, 120°]$. There is, however, a non-monotonic trend in recovery with wettability, similar to that observed for uniformly-wet systems, Fig. 7: in Fig. 11, oil recovery initially increases and then decreases with oil-wet fraction. When the oil-wet fraction is high, displacement proceeds by piston-like advance through the wider elements: once these connect, the water relative permeability increases rapidly, leading to modest overall oil recovery. The water-wet regions of the pore space are filled first during waterflooding. When the fraction of water-wet elements is small, these regions are filled first, but do not significantly increase the connectivity of the water. Once filled, further displacement of larger elements occurs, seeded from these water-wet patches. Only at relatively high water saturation is the water connected across the system through the centers of the pore space. This leads to a very low water relative permeability over a wide saturation range, giving a favorable oil recovery. As more of the pore space becomes water-wet, these regions connect and the water relative permeability is higher. Furthermore, oil can be trapped in the water-wet portions of the pore space. These two effects lead to a lower recovery when the water-wet fraction is larger. There is an optimal water-wet fraction (around 15%–30% for Berea, 5%–20% for S, 10%–30% for F). The key to our successful reproduction of the experimentally-observed variation in recovery — Section 2 — is the difference in oil-wet fraction.

Network C, in contrast, displays a rather different behavior. For each value of $S_{wi}$, the recovery is initially very high but decreases dramatically with a minor increase in water-wet fraction. The low coordination number of this network allows oil and water to become easily disconnected. When the network is entirely oil-wet, oil remains connected through layers and the residual saturation is very low, leading to high recoveries. However, a small number of water-wet pores — which are filled first during waterflooding — is sufficient to give a high residual oil saturation, as filling a few elements strands significant quantities of oil. This is confirmed by the relative permeabilities and fractional flows shown in Fig. 12: a small proportion of water-wet elements is sufficient to give a very large

Fig. 11. Oil recovery as a function of oil-wet fraction.
residual oil saturation. The poor connectivity of the network means that there is only a narrow range of saturation where both oil and water relative permeabilities are greater than around 0.01.

4. Conclusions

We have studied the effects of wettability on waterflooding recovery using a pore-scale network model. We validated the model against experimental data in the literature on mixed-wet Berea sandstone and then applied it to study multiphase flow through four networks extracted from different types of rock: a sand pack, a poorly consolidated sandstone from the Middle East, a granular carbonate and Berea sandstone. We studied the effects of initial water saturation, contact angle distribution and oil-wet fraction on recovery. Our key conclusions are outlined below.

For a uniformly-wet system recovery increases as the system becomes less water-wet and reaches a maximum for oil-wet conditions where recovery is approximately constant for average intrinsic contact angles above 100°. As the initial water saturation increases, recovery decreases in water-wet systems whereas in oil-wet systems it initially increases and then decreases.

For mixed-wet media the oil-wet fraction plays a more important role in determining recovery than the contact angle in the oil-wet regions. Optimal recovery occurs when a small fraction of the system is water-wet. Pore structure plays a relatively minor role in the generic behavior, although it does influence the initial saturation for optimal recovery and the magnitude of the recovery.

Nomenclature

\begin{itemize}
  \item FOIP: fraction of oil in place
  \item \(l_w\): Amott water index
  \item \(l_o\): Amott oil index
  \item \(l_{w-o}\): Amott–Harvey index
  \item \(K\): water absolute permeability, mD
  \item \(k_{rw}\): water relative permeability
  \item \(k_{ro}\): oil relative permeability
  \item PV: pore volume
  \item \(S_{wi}\): initial water saturation
  \item \(r_p\): pore radius, μm
  \item \(r_t\): throat radius, μm
  \item \(\phi\): porosity
  \item \(\theta\): average intrinsic contact angle
\end{itemize}

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