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### A Model for Wettability Alteration in Fractured Reservoirs

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#### Abstract

Many of the world's oil reservoirs are naturally fractured. Injected water will flow into this highly permeable network and not sweep the matrix containing most of the oil. Spontaneous imbibition can drive oil into the fractures by capillary forces. However the wettability of the reservoir is critical for the ultimate potential of oil recovery. Experimental results indicate that exposing chalk cores to seawater or similar brines may alter the wettability towards a more water-wet state. In a fractured reservoir this exposure will happen by molecular diffusion and by water imbibing into the matrix. The injected brine is not in chemical equilibrium with the in-situ rock, water and oil so that chemical reactions occur. Experiments have shown that for chalk rocks the relevant processes are adsorption/desorption of ions on the mineral surface, precipitation/dissolution of minerals or ion exchange. We have developed a model where a reservoir is defined by a fracture surrounded by matrix on both sides. The injected brine contains a component that can adsorb on the matrix surface. These changes of the mineral surface are assumed to alter the wettability towards a more water-wet state. The wettability alteration is described by shifting curves for relative permeability and capillary pressure from curves representing oil-wet conditions towards curves representing more water-wet conditions. The model can make predictions regarding the effect of matrix properties such as wettability and external parameters such as schedule of brine compositions and injection rate. The understanding of the coupling between wettability alteration controlled by water-rock chemistry and fracture-matrix flow is highly relevant for gaining more insight into the observed high recovery in the North Sea chalk field Ekofisk.

#### Introduction

In fractured reservoirs it is essential to mobilize the matrix oil to gain a substantial recovery factor. Injecting water will not displace oil as effectively as in conventional reservoirs since advective flow is concentrated to fracture networks. A main recovery mechanism in such reservoirs is often spontaneous imbibition (SI) of the injected fluid that expels oil back to the fracture network for advective transport. The wettability of the matrix rock is an important characteristic that defines whether the water will be sucked into the rock (water-wet rock) or simply flow around (oil-wet rock). It seems that in some cases wettability is not a static parameter and can be affected.

In this paper we consider a fractured reservoir as modeled by a fracture surrounded by matrix on both sides. We assume advective flow in the fracture from an injector to a producer well, with spontaneous imbibition along the matrix interacting with the fracture flow. A component in the injected fluid can diffuse into the matrix, adsorb on the rock and alter the wettability towards a more water-wet state, depending on the degree of adsorption. We name the component WA (wettability alteration) agent. The wettability alteration is represented by shifting relative permeability and capillary pressure curves from relatively oil-wet towards relatively water-wet. Oil is continuously driven out from the matrix and into the fracture by capillary forces and water flows back countercurrent into the porous medium. Oil is then pushed towards the producer by the advective flow in the fracture.

The paper is organized such that we first present the main equations of the model. The behavior of the model for different conditions is then illustrated by numerical examples before some conclusions are made.

#### Experimental brine-dependent oil-recovery

A lot of experimental work has been carried out to improve recovery from oil-wet and mixed-wet fractured reservoirs.

The role of wettability on recovery from fractured rock was discussed in (Graue et al., 2001, Haugen et al., 2010). Blocks of porous media with defined fracture surfaces were flooded with brines and the importance of wettability was demonstrated by increased tendency to adsorb water into the more water-wet blocks as observed using MRI techniques. This also demonstrated the typical flow pattern of fractured reservoirs.

In (Zhang et al., 2007, Zhang and Austad, 2006) imbibition tests were carried out where relatively oil-wet chalk cores were submerged in seawater-like brines. The resulting oil recovery was clearly affected by changing composition of the imbibition brines. Simply modifying the setup of the natural ions in seawater had significant impact on the oil recovery. The mechanism was believed to be a chemically induced wettability alteration towards a more water-wet state. Other mechanisms suggested for wettability alteration are the use of surfactants (Delshad et al., 2009) or heated injection fluids (Al-Hadhrami and Blunt, 2001).

### Previous modeling

Different models exist on the topic of brine-dependent EOR and fracture flow. In (Yu et al., 2009, Yu et al., 2008) a 1D model of spontaneous imbibition core experiments was considered where an adsorbing agent altered the wettability towards more water-wet and hence increased the recovery. Similar models (Evje and Hiorth, 2011, Andersen and Evje, 2012a) with a more consistent geochemical description, see (Andersen et al., 2012), correlated geochemically induced modifications of the matrix to changes in wettability and were matched against experimentally observed oil recovery.

Analytical solutions for 1D transport of solutes in a 2-phase system by spontaneous and forced imbibition were presented in (Schmid et al., 2012). They accounted for arbitrary flow functions and dispersion and adsorption of the component. An underlying assumption was that the chemistry did not affect the flow functions.

In (Gautam and Mohanty, 2004) the authors modeled an experimental setup where water flowed in a thin channel (fracture) between two core plugs and oil was recovered from the cores by counter-current spontaneous imbibition.

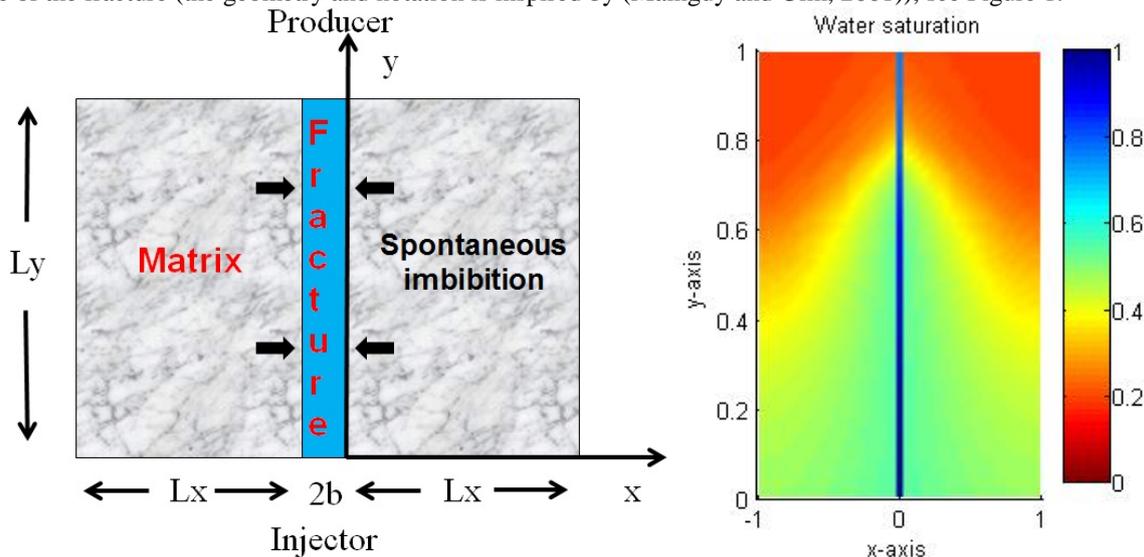
A model for solute transport along a fracture by molecular diffusion and chemical dissolution/precipitation with the matrix was given in (Mainguy and Ulm, 2001). They gave an analytical expression for the long-term behavior of the front.

(Rangel-German and Kovscek, 2002) presented experimentally how water flowing through a fracture would imbibe to a surrounding matrix and presented an analytical solution for the combined matrix-fracture flow by extending a 1D solution for imbibition. The main assumption was a constant capillary diffusion coefficient and non-changing flow functions. The authors showed how the initial recovery would be linear with time, while later it would be linear with the square root of time, consistent with experimental behavior.

A previous paper on the model discussed in this paper is given in (Andersen and Evje, 2012b). In that paper the model was considered at fixed wettability without component transport and the key model parameters were discussed.

### System description and modeling

Consider a horizontal plane  $(x, y)$  such that the  $y$ -axis by definition runs parallel with a linear fracture of length  $L_y$  and width  $2b$ . The fracture cuts the plane in half and porous medium (matrix region) is located on either side going a length of  $L_x$  on either side of the fracture (the geometry and notation is inspired by (Mainguy and Ulm, 2001)), see Figure 1.



**Figure 1** Coordinate system for the reservoir. Advection occurs along fracture from injector to producer, imbibition flow happens along matrix towards the fracture. Water distribution after flooding 1 reservoir volume is also illustrated for reference case.

The fracture is thus confined to

$$0 \leq y \leq L_y, \quad -2b \leq x \leq 0, \quad (1)$$

while the matrix is confined to

$$\begin{aligned} (x,y): \quad & -2b - L_x < x < -2b, \quad 0 < y < L_y \\ (x,y): \quad & 0 < x < L_x, \quad 0 < y < L_y \end{aligned} \quad (2)$$

The injector and producer are located at the surfaces

$$(x,y)^{\text{inj}} = \{-2b < x < 0, y=0\}, \quad (x,y)^{\text{prod}} = \{-2b < x < 0, y=L_y\} \quad (3)$$

The system contains 2 liquid phases, namely oil (o) and water (w), which are immiscible. The water phase can carry a component that we term WA (wettability alteration) agent as we assume this component has the potential to interact with the matrix and affect wettability properties. Relevant local variables are phase pressures  $p_w, p_o$ , phase saturations  $S_w, S_o$  and WA component concentration in the water phase:  $c$ . We make use of the following constraints:

- The saturations are dependent as  $S_o + S_w = 1$ . From this we eliminate the oil saturation  $S_o$ .
- The phase pressures  $p_w, p_o$  are in local equilibrium as given by the capillary pressure,  $P_c$ , which is a known function,  $p_o - p_w = P_c(S_w)$ . This is used to eliminate the water phase pressure,  $p_w$ .
- From boundary conditions we can determine the total velocity at any position. This parameter will replace the oil phase pressure  $p_o$ .

Accordingly the final model will be expressed by the 2 variables water saturation  $S_w$  and component concentration  $c$ . Equations for the matrix are given below (the derivation is similar to that in (Yu et al., 2008)). The water phase flow is controlled by a gradient in capillary pressure while the component flows along with the water phase, but also by dispersion/diffusion and is retained by adsorption.

$$\begin{aligned} \varphi^m \partial_t S_w &= -\partial_x (\lambda_o^m(S_w, c) f_w^m(S_w, c) K^m \partial_x P_c^m(S_w, c)) \\ \varphi^m \partial_t (S_w c + A(c)) &= -\partial_x (\lambda_o^m(S_w, c) f_w^m(S_w, c) K^m c \partial_x P_c^m(S_w, c)) \\ &\quad + \varphi^m \partial_x (S_w D^m(v_w^m) \partial_x c) \end{aligned} \quad (4)$$

$(0 < x < L_x; 0 < y < L_y)$

Flow in the fracture is controlled by an advective term due to injection and dispersion of the component. In addition source terms relate the fracture flow with flow in the matrix.

$$\begin{aligned} \varphi^f \partial_t S_w + \varphi^f v_T^f(t) \partial_y (f_w^f(S_w)) &= -\frac{1}{b} (K^m \lambda_o^m(S_w, c) f_w^m(S_w, c) \partial_x P_c^m(S_w, c))^m \Big|_{\{x=0^+\}} \\ \varphi^f \partial_t (S_w c) + \varphi^f v_T^f(t) \partial_y (f_w^f(S_w) c) &= -\frac{1}{b} (K^m \lambda_o^m(S_w, c) f_w^m(S_w, c) c \partial_x P_c^m(S_w, c))^m \Big|_{\{x=0^+\}} \\ &\quad + \frac{1}{b} (\varphi^m S_w D^m(v_w^m) \partial_x c)^m \Big|_{\{x=0^+\}} \\ &\quad + \partial_y (\varphi^f S_w D^f(v_w^f) \partial_y c). \end{aligned} \quad (5)$$

$(-2b < x < 0; 0 < y < L_y)$

We work with average values in the fracture, meaning that these variables only depend on  $(y, t)$  and not  $x$ . The constant parameters above are fracture width  $2b$ , porosity  $\varphi^i$ , absolute permeability  $K^i$  where superscript  $i = m, f$  denotes matrix- or fracture-specific properties.  $v_T^f$  is the total pore velocity in the fracture and is defined by injection conditions. Also we define phase mobilities for matrix and fracture as

$$\lambda_j^m(S_w, c) = \frac{k_{rj}^m(S_w, c)}{\mu_j}, \quad \lambda_j^f(S_w) = \frac{k_{rj}^f(S_w)}{\mu_j}, \quad (6)$$

and flow functions as

$$f_j^m(S_w, c) := \frac{\lambda_j^m}{\lambda_w^m + \lambda_o^m}, \quad f_j^f(S_w) := \frac{\lambda_j^f}{\lambda_w^f + \lambda_o^f}. \quad (7)$$

Index  $j$  refers to oil (o) or water (w),  $k_{rj}$  is relative permeability and  $\mu_j$  viscosity. As noted above, the relative permeabilities and capillary pressure curves in the matrix are functions of both water saturation  $S_w$  and concentration  $c$  as we assume the WA component can alter the flow functions by changing wettability of the matrix. The WA component is however assumed to behave inertly in the fracture.

### Relative permeability and capillary pressure functions

In this section we present expressions for relative permeability curves ( $k_{ro}, k_{rw}$ ) and scaled capillary pressure curves  $J$ . For the matrix we will consider typical curves representative of either water-wet ( $k_{ro}^{m,ww}, k_{rw}^{m,ww}; J^{m,ww}$ ) or oil-wet state ( $k_{ro}^{m,ow}, k_{rw}^{m,ow}; J^{m,ow}$ ) as functions of water saturation and then include the wettability dependence as an interpolation between the curves. For the fracture we assume there is no wettability dependence.

### Fixed wettabilities

Introduce the normalized water saturation  $S^* = \frac{S_w - S_{wr}}{1 - S_{or} - S_{wr}}$  where  $S_{wr}$  and  $S_{or}$  represent residual saturation values at which the phase does not flow. Relative permeabilities are modeled using Corey type correlations:

$$\begin{aligned} k_{rw}(S_w) &= k_w^* (S^*)^{Nk_w}, \quad S_{wr} \leq S_w \leq 1 - S_{or}, \\ k_{ro}(S_w) &= k_o^* (1 - S^*)^{Nk_o}, \quad S_{wr} \leq S_w \leq 1 - S_{or}. \end{aligned} \quad (8)$$

$Nk_w$  and  $Nk_o$  are Corey exponents and  $k_w^*$  and  $k_o^*$  are end point relative permeability values. Separate curves are defined by specifying different parameters.

As a model for capillary pressure we consider a dimensionless function  $J$  of the following form  $P_c(S^*) = P_{c,\max} J(S^*)$ .

For the matrix we let imbibition curves  $J^m$  be defined as follows

$$J^m(S_w) = \frac{a_1}{1 + k_1 S^*} - \frac{a_2}{1 + k_2 (1 - S^*)} + b_1, \quad (9)$$

see (Skjaeveland et al., 2000) for a similar correlation. For oil-wet or water-wet matrix we choose parameters  $a_1, a_2, b_1, k_1, k_2$  in accordance with the characteristic shape of experimental capillary pressure data.  $J^m$  will decrease with  $S^*$  and be bounded to the interval  $-1 < J^m < 1$ . In accordance with other works (Terez and Firoozabadi, 1999) we assume here the capillary pressure in the fracture is identical to zero:

$$J^f = 0 \quad (10)$$

### Altering wettabilities

We couple the alteration in wettability to the adsorption of WA component on the matrix surface. The amount of adsorbed species (measured per porous volume) is assumed to be given by a Langmuir isotherm:

$$A(c) = A_{\max} \frac{r c}{1 + r c} \quad (11)$$

The wettability alteration is coupled to the relative adsorption  $w(c) = \frac{A(c)}{A_{\max}}$ , that is, how much is adsorbed compared to what is obtainable. The interpolation is assumed to be linear in  $w$ :

$$\begin{aligned} k_{rw}(S_w, c) &= w(c) k_{rw}^{ww}(S_w) + [1 - w(c)] k_{rw}^{ow}(S_w), \\ k_{ro}(S_w, c) &= w(c) k_{ro}^{ww}(S_w) + [1 - w(c)] k_{ro}^{ow}(S_w), \\ J(S_w, c) &= w(c) J^{ww}(S_w) + [1 - w(c)] J^{ow}(S_w). \end{aligned} \quad (12)$$

If there is no adsorbed WA component then no wettability alteration has occurred and the matrix remains oil-wet. Then  $w = 0$  and the curves are given by the oil-wet state. On the other hand, if the matrix has adsorbed its maximal amount of WA component the matrix becomes water-wet. Then  $w = 1$  and the curves are given by the water-wet state.

### Dispersion

The dispersion coefficient  $D$  is given by an advective and diffusive part:

$$D^i = \alpha_{disp}^i |v_w^i| + D_{mol}, \quad (13)$$

where  $i = m, f$  refers to matrix or fracture,  $\alpha_{disp}^i$  (m) is the dispersivity of the medium,  $v_w^i$  the water pore velocity and  $D_{mol}$  the molecular diffusion coefficient of the species.

### Initial and boundary conditions

In addition to the transport equations the system is equipped with initial conditions of the following form:

$$S_w(x, y, t=0) = S_{w,0}(x, y), \quad c(x, y, t=0) = c_0(x, y). \quad (14)$$

Boundary conditions for the fracture at the injector is given by the composition of the injected fluid:

$$S_w(y=0, t) = S_w^{inj}, \quad c(y=0, t) = c^{inj}. \quad (15)$$

It is assumed dispersion is only relevant inside the reservoir and there is no flux related to this at the injector or producer. The boundary at the exterior of the matrix is assumed closed.

**Numerical solution**

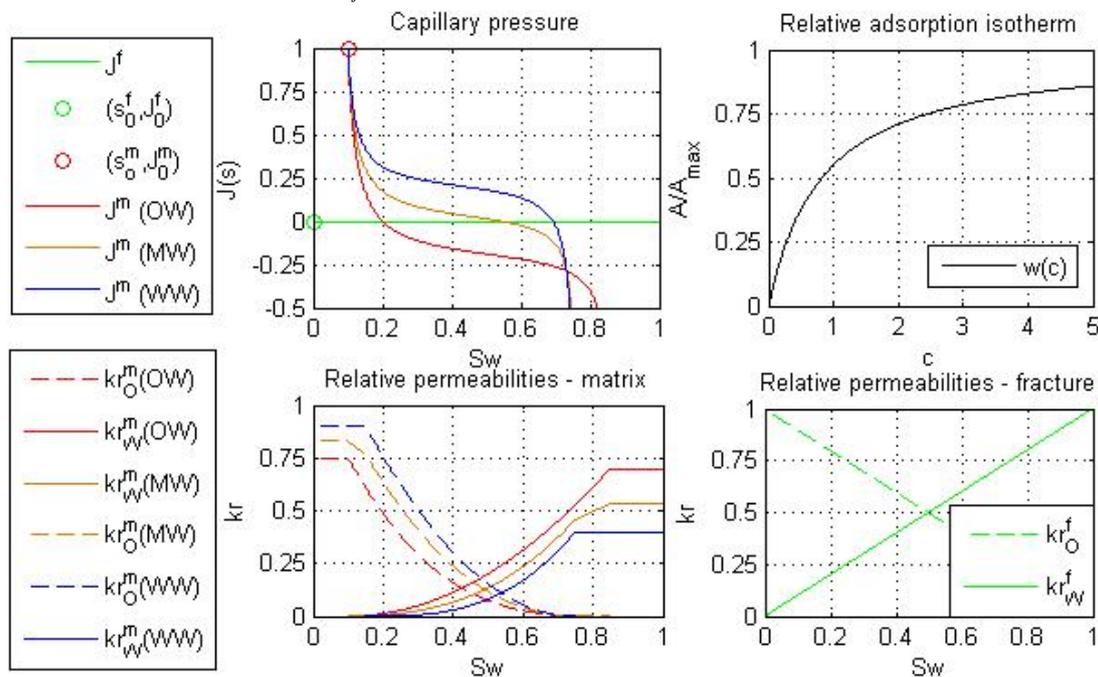
The system is solved by an operator splitting approach based on making two subsystems where flow either goes in x- or y-direction and we switch between solving each system. The system is discretized into 20 cells along the x-axis and 60 cells along the y-axis.

**Numerical investigations**

**Input**

As constant input parameters we use length between injector and producer  $L_y=100$  m, fracture width  $2b = 0.001$  m, porosities  $\varphi^f = 1$ ,  $\varphi^m = 0.20$ , fracture spacing  $2L_x=0.10$  m, injection velocity along fracture  $v_T^f=10$  m/d, matrix permeability  $K^m = 5$  mD  $= 5 \cdot 10^{-15}$  m<sup>2</sup>, viscosities  $\mu_o=\mu_w = 1 \cdot 10^{-3}$  Pa s and reference capillary pressure is set to  $P_{c,max} = 250$  Pa. The molecular diffusion coefficient is set to  $D_{mol} = 1 \cdot 10^{-9}$  m<sup>2</sup>/s, the dispersivities  $\alpha_{disp}^m = \alpha_{disp}^f = 0.01$  m. The adsorption parameter  $r$  is set to 1.22. Initial saturations are  $S_{w,0}^m = 0.10$  in the matrix and  $S_{w,0}^f = 0.0$  in the fracture. Initial concentrations are  $c_0 = 0.0$ . Water is injected, so  $S_w^{inj} = 1$ . With the given parameters we note that 1 reservoir pore volume (RV) corresponds to 21 fracture volumes (FV).

Other input parameters that we will vary are the injected WA concentration  $c_{inj}$  and the maximum amount of adsorbed species  $A_{max}$ . As reference values we let  $c_{inj} = 1$  and  $A_{max} = 1.5$ .



**Figure 2 Scaled capillary pressure  $J$  and relative permeability curves  $k_{ro}$ ,  $k_{rw}$  for matrix (at different wettabilities: oil-wet, mixed-wet, water-wet) and fracture and scaled adsorption isotherm for WA component. Mixed-wet curves correspond to reference case with WA concentration  $c=1$ .**

Curves for capillary pressure and relative permeability are given in Figure 2. The matrix curves are defined for oil-wet, water-wet and mixed-wet state (an interpolation corresponding to  $c = 1$ ).

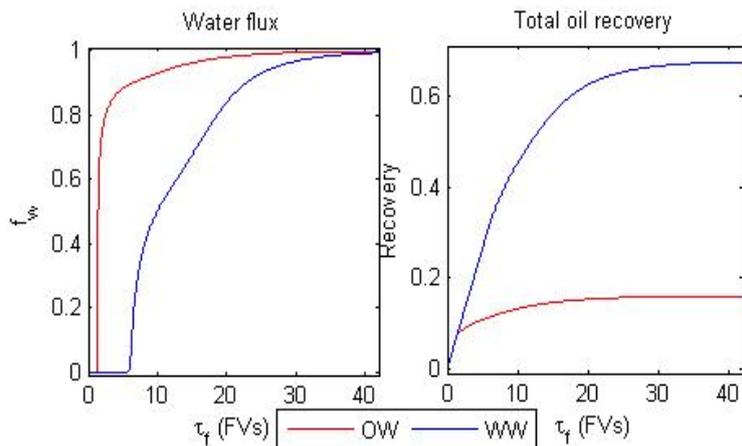
**Behavior at constant wettability**

First we consider the extremes of the model. For the given reservoir and injection conditions we compare the behavior if the matrix is completely oil-wet or completely water-wet. Note from the capillary pressure curves that we allow some imbibition in the more oil-wet case, but the matrix saturations will not exceed 0.20. In the water-wet case they may reach 0.7. Results are shown in Figure 3 and Figure 4.

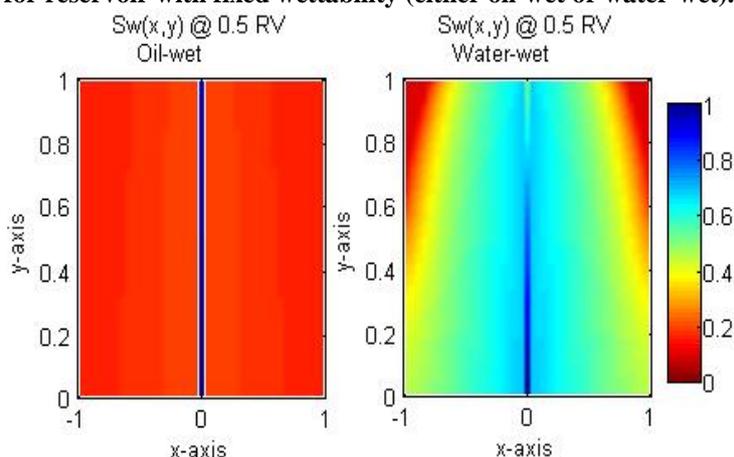
It is observed that the water breaks through first for the oil-wet reservoir since the water mostly bypasses the matrix. Breakthrough is followed by a high water flux indicating that the injected water mostly flows through the fracture and does not imbibe.

In the water-wet case water breakthrough does not occur until several fracture volumes (ca 1/3 RV) have been injected indicating an efficient imbibition into matrix. It is followed by a gradually increasing water flux indicating that much of the injected water still goes into the matrix. As seen by the distribution of water in each case after 0.5 RV a lot of water has gone

into the water-wet matrix, while the saturations are low in the oil-wet matrix.



**Figure 3 Producer water flux and oil recovery measured vs. scaled time (# FV water injected) for reservoir with fixed wettability (either oil-wet or water-wet).**



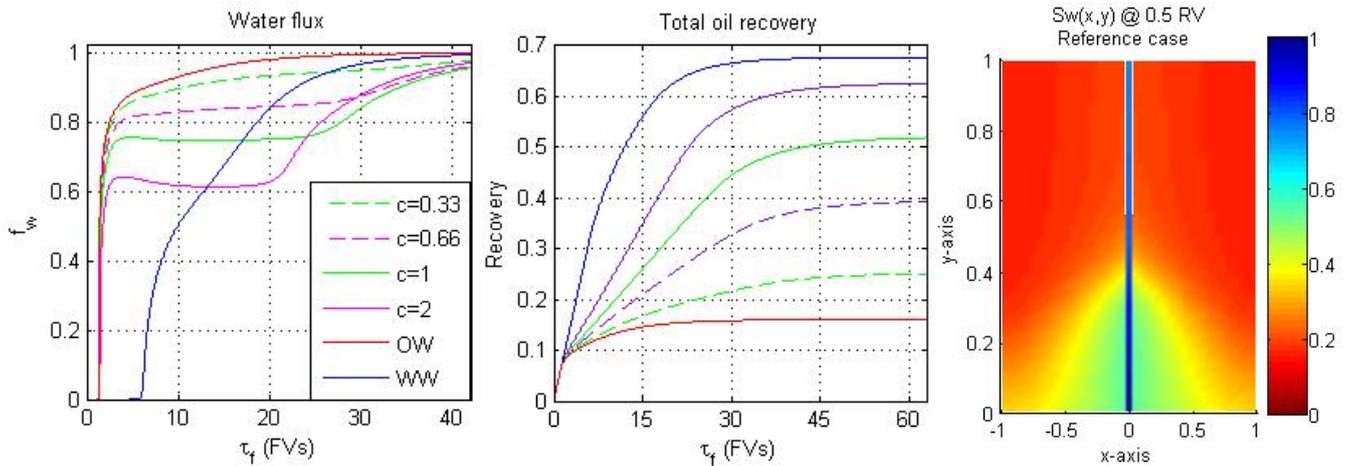
**Figure 4 Distribution of water in reservoir after having injected 0.5 RV for oil-wet and water-wet matrix. Note that the presented axes are scaled as  $x/L_x$  and  $y/L_y$ .**

### Injecting different concentrations of WA agent

To study the interplay between wettability alteration (controlled by the WA agent) and matrix-fracture flow we let the injected brine carry a certain concentration of the WA agent. As injection begins the matrix is originally oil-wet, but some of the water imbibes and carries with it the WA agent. The component adsorbs to the matrix, but the water flow induces dispersion which, in addition to diffusion, spreads the WA agent towards even concentrations. As the agent adsorbs in matrix the capillary pressure increases and the matrix-fracture transfer picks up. Once the agent concentration evens out and the potential of adsorbed amount is reached there is no more diffusive flow across the matrix-fracture interface, nor will there be any more alteration of the wettability. A certain concentration of the WA agent will only change the wettability to some extent (as given by how much will adsorb) and the ultimate recovery is therefore bounded by the concentration.

Several tests were run where the injected concentrations were varied. Results in terms of water flux and oil recovery are shown in Figure 5. In all cases the water breakthrough is very early, indicative of an oil-wet matrix. The water flux is high as the matrix allows much water to bypass. As the component adsorbs in the matrix more water will imbibe which is seen by a lower water flux compared to the oil-wet case. For higher WA concentrations the capillary pressure stays positive for higher saturations. The competition between lowered capillary pressure for increased saturations and increased capillary pressure for higher WA adsorption leads to a slowing down of the water flux and in the cases of high concentrations, even a reduction (see case with  $c=2$ ). The onset of wettability alteration produces a break-off point from the oil-wet reference curve. The water flux  $f_w$  increases fast in the early phase, but then reaches a level where it flats out (imbibition becomes significant) before steadily approaching 1 as the potential oil is recovered.

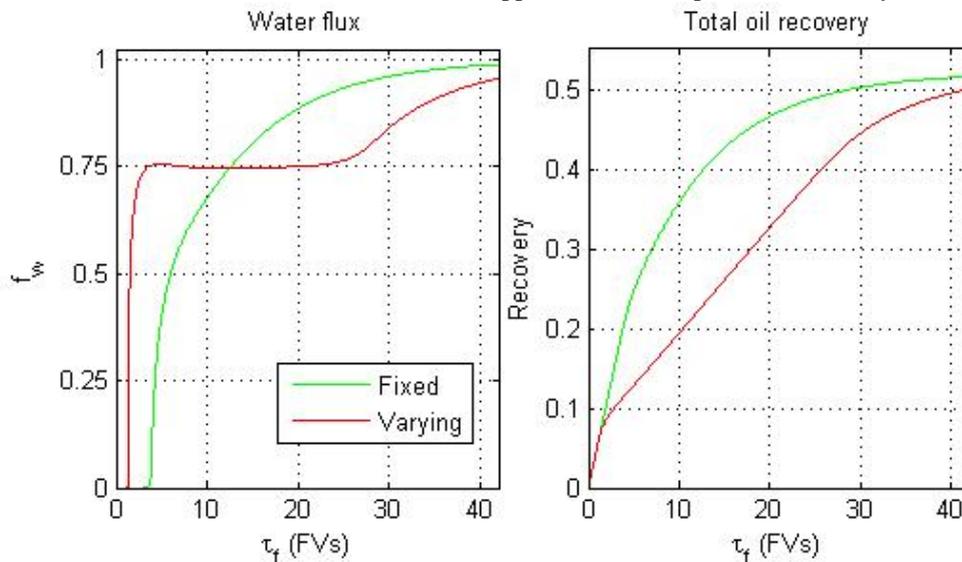
Also the water distribution is depicted in Figure 5 for the reference case after injecting 0.5 RV of water. Comparing with Figure 4 more water has imbibed than the oil-wet reservoir, but less than in the water-wet. The local saturations are not as high as in the water-wet case either due to limitation on the degree of alteration. The section closest to the injector adsorbs component first and therefore becomes more water-wet first. Since the process of wettability alteration takes time much of the first injected water has passed through the fracture.



**Figure 5 Producer water flux and oil recovery measured vs. scaled time ( $\tau^f = \#FV$  water injected) for different injected concentrations compared to oil-wet and water-wet cases. Water distribution for reference case ( $c=1$ ) is given after 0.5 RV.**

An additional comparison was made for the reference case  $c=1$  where we distinguish between fixed wettability corresponding to this concentration and a gradual alteration as WA component adsorbs. The results are given in Figure 6.

When the initial wettability is more water-wet the water breakthrough is delayed and the imbibition of water is only reduced due to the weakening of the capillary gradient. The water flux therefore increases gradually until no more oil is produced. Considering the case with varying wettability we first see breakthrough as a rapid increase in the water flux, but then the flux seems to stabilize and remain constant which also appears as a linear profile in recovery.

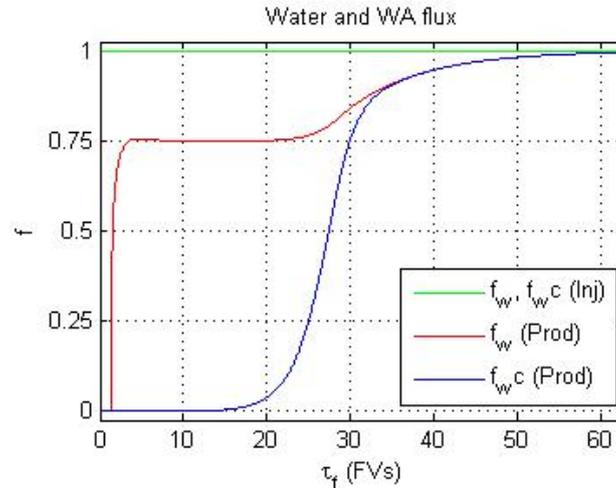


**Figure 6 Producer water flux and oil recovery vs. time (# FV water injected) comparing gradual wettability alteration to fixed wettability for the reference case ( $c=1$ ).**

Both in the case of fixed and varying wettability we observe identical slopes in recovery before water breakthrough. The fixed wettability case only has one linear phase before the profile gradually flattens out, but the varying wettability case seems to have two linear phases. The second linear phase results from a dynamic equilibrium between the advective and imbibing forces. The supply of component alters the wettability to increase capillary suction at the same rate as the supply of water decreases the rate. When the potential for wettability alteration expires, the capillary forces weaken and more water will bypass the matrix. Note that the water flux in the varying case is lower than in the fixed case after some time and will produce oil faster than in the case of fixed wetting. However, the recovery curve is always lagging behind, although they move towards the same ultimate recovery.

In Figure 7 we compare the outgoing flux of the WA component with that of water. Clearly, the WA component arrives later to the producer than the water front. This is only due to the interaction with the matrix as the fracture is initially oil-saturated. The component disperses into the connate water in the matrix and also adsorbs to the matrix rock surface. This process effectively strips the water for its component and as a result there is no significant production of the component until

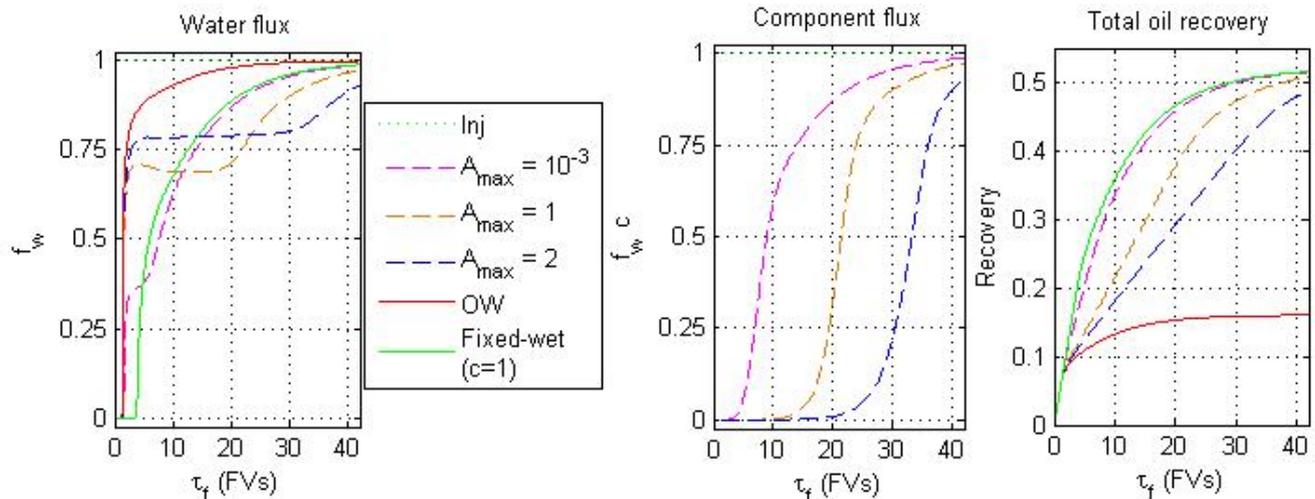
almost an entire RV has been injected. Note that the time of component production coincides with the time when the water flux begins to increase again. At this point the reservoir does not adsorb the component very efficiently as its storage becomes saturated for the given concentration. Therefore the wettability alteration stops and does not sustain the capillary drive. The imbibition process weakens and recovery stops.



**Figure 7 Injected and produced fluxes of water and component  $f_w, f_w c$  vs. time (# FV water injected) for reference case ( $c=1$ ).**

### Required amount of adsorption

When the WA agent adsorbs to the surface to change wettability it is important to know how much species is required to achieve a certain effect. If the matrix requires several pore volumes of injected water to alter the wettability significantly it may be an expensive option compared to other techniques. The required amount is directly linked to how much of the species can adsorb on the matrix surface.



**Figure 8 Injected and produced water and WA component flux  $f_w, f_w c$  and oil recovery for different values of  $A_{max}$  when  $c=1$ . Cases are also compared to cases of fixed wettability corresponding to  $c=1$  or oil-wet.**

In Figure 8 we have varied  $A_{max}$  which corresponds to how much component must adsorb on the surface for maximum wettability alteration. It is seen that oil recovery is delayed when  $A_{max}$  is high (the ultimate recovery is the same). If  $A_{max}$  is very small (compared to the injected concentration) it seems the dynamic transition converges towards the case with fixed water-wet state. This is because the wettability will change almost instantaneously at the front and the water will lose negligible component by adsorption. The dilution into the connate water is also of little importance in this case, as diluted concentrations still are very effective. When  $A_{max}$  increases the water rapidly loses its species by adsorption and more injected water is required to build up the correct amounts. This is reflected in the late arrival of the component front in cases of high adsorption.

Note that in the case of fast wettability alteration the recovery profile resembles that of a square root of time shape, however when the transition is very gradual the recovery profile is linear.  $A_{max}$  controls the slope of this linear phase after water breakthrough, or more interesting, to which degree the recovery resembles a linear or square root profile vs time.

## Concluding remarks

In this article we have presented a model to illustrate how brine-dependent oil recovery by imbibition may behave in a matrix-fracture system. Experimental evidence has shown that imbibition is an important recovery mechanism in fractured reservoirs and that the ultimate recovery is controlled by wettability. It is possible to alter the wettability towards a more water-wet state and hence increase the potential for imbibition by introducing chemically reactive components (ions, chemicals, etc.) to the system that will alter the initial equilibrium state.

The model considered injection of water into a reservoir where advective flow occurred in a fracture channel, while capillary flow appeared in the matrix to feed the fracture with oil. As water would imbibe the component would adsorb to the matrix and alter the wettability. The following observations were made:

1. If the matrix is fixed oil-wet water breakthrough occurs quickly and recovery is low. If the matrix is water-wet water breakthrough is late and recovery is high.
2. The component enters the matrix by imbibition of the water phase, dispersion and diffusion. The diluting into connate water and adsorption onto the matrix rock delays the component breakthrough compared to the water front.
3. Altering concentrations would alter the amount of adsorption onto the rock. Therefore it is possible to observe differences in ultimate recovery when changing the concentration of the WA component.
4. Since the component takes some time to mix into the matrix the reservoir will initially behave as oil-wet. This means that the time of water breakthrough will be similar as for an oil-wet reservoir. However, since the capillary drive is strengthened over time a substantial amount of water will go into the matrix instead of through the fracture. This phase was observed as a linear recovery profile with lower slope than before breakthrough.
5. The amount of component that needs to adsorb to make a wettability alteration is an important parameter and will tell how fast the alteration goes. If the amount is negligible the alteration will follow the component front which lies ahead of the water front due to dispersion and diffusion. The matrix will then be water-wet at first contact with the imbibed water.
6. If much component needs to adsorb the wettability alteration is slower and recovery is controlled by how fast the reservoir is fed by the component. A linear profile in recovery develops which has a higher slope vs time if less needs to adsorb.

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## Appendix

### Curve parameters

For oil-wet matrix we use the following parameters:

$$\begin{aligned} S_{wr} &= 0.1, S_{or} = 0.15, k_w^* = 0.7, k_o^* = 0.75, Nk_w = 2, Nk_o = 3, \\ a_1 &= 1.24, a_2 = 0.82, k_1 = 30, k_2 = 40, b_1 = -0.22, \end{aligned} \quad (16)$$

For water-wet matrix we use

$$\begin{aligned} S_{wr} &= 0.15, S_{or} = 0.25, k_w^* = 0.4, k_o^* = 0.9, Nk_w = 3, Nk_o = 2, \\ a_1 &= 0.82, a_2 = 1.23, k_1 = 30, k_2 = 50, b_1 = 0.2. \end{aligned} \quad (17)$$

## Nomenclature

A short explanation of the symbols used are given below:

$A$	=	Adsorbed WA agent
$A_{max}$	=	Maximum adsorption WA agent
$a_1, a_2, b_1, k_1, k_2$	=	Capillary pressure correlation parameters
$b$	=	Fracture halfwidth
$c$	=	WA agent concentration
$D_{mol}$	=	Molecular diffusion coefficient
$D^i$	=	Dispersion coefficient
$f_j^i$	=	Phase flow function
$FV$	=	Fracture volume
$J^i$	=	Scaled capillary pressure
$K^i$	=	Absolute permeability
$k_j^*$	=	Endpoint relative permeability
$k_{rj}^i$	=	Relative permeability
$L_x$	=	Matrix width from fracture
$L_y$	=	Length of fracture
$Nk_j$	=	Corey exponent

$p_c^i$	=	Capillary pressure
$r$	=	Adsorption isotherm parameter
$RV$	=	Reservoir volume
$S^*$	=	Normalized water saturation
$S_{jr}$	=	Residual saturation
$S_w$	=	Water saturation
$v_T^i$	=	Pore velocity
$WA$	=	Wettability alteration
$w$	=	Relative adsorption WA agent
$\alpha^i$	=	Dispersivity
$\lambda_j^i$	=	Phase mobility
$\mu_j$	=	Viscosity
$\phi^i$	=	Porosity

Note indices  $i=m, f$  (matrix, fracture) and  $j=o, w$  (oil, water).

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