Fluid Flow in Fractured Carbonates: Wettability Effects and Enhanced Oil Recovery

By
Åsmund Haugen

A dissertation submitted to the Department of Physics and Technology at the University of Bergen, Norway, in partial fulfillment of the requirements for the degree of philosophiae doctor

Table of Contents

Summary

The oil recovery in naturally fractured reservoirs is strongly linked to the relationship between the fractures and the rock matrix. Fractures provide large surface area for spontaneous capillary brine imbibition and may assist in providing high production rates even if matrix permeability is low. The efficiency of capillary imbibition strongly depends on the wettability of the systems. Large remaining oil reserves are located in oil-wet reservoirs where capillary forces retain oil in the rock matrix and recovery by imbibition is suppressed. Fluid flow in fractured reservoirs is dominated by high permeable fracture networks resulting in poor sweep efficiency and potentially low oil recovery where oil remains trapped in the rock matrices. Increasing energy demand and rising oil prices increase the focus on improved oil recovery in general, and in particular for fractured reservoirs because of enormous potential of improved oil recovery in these reservoirs. The technologies to improve oil recovery include disciplines such as drilling, seismics, geological characterization, integrated operations and reservoir management in addition to new EOR methods. This thesis focuses on improved understanding of the mechanisms of flow in fractured porous systems, and included experimental and numerical studies of the influence from wettability and fractures on oil recovery. This provided the basis for experimental investigations of two EOR methods.

The impact from fractures on oil recovery and saturation development in chalk and limestone was investigated during laboratory waterfloods with wettabilities ranging from strongly water-wet to moderately oil-wet conditions. The results are found in **Paper 1-4**. Visualization by either Magnetic Resonance Imaging (MRI) or Nuclear Tracer Imaging (NTI) demonstrated how fractures influence the displacement pattern. At strongly water-wet conditions, the displacement was capillary dominated and the fractures had minor impact on ultimate recovery, although significantly changing the water front dynamics. At less water-wet states, the displacement was less capillary dominated, thereby increasing the impact from fractures on ultimate recovery and water breakthrough time. At oil-wet states, no fluid transfer from matrix to fracture by capillary imbibition was observed. Recovery was based on viscous displacement alone, which was very limited in the highly permeable fractured system. MRI was used on a smaller scale to investigate capillary continuity across open fractures in limestone core plugs at moderately oil-wet conditions. Oil droplets on the fracture surface established capillary contact during an oilflood. This illustrated the mechanistic similarity between oilfloods at moderately oil-wet conditions and waterfloods at moderately water-wet conditions, forming capillary continuity by liquid phase bridges in both cases. A capillary threshold pressure for water to enter the moderately oil-wet matrix was identified during waterflooding.

Experimental results were history matched using numerical reservoir simulation models. Dynamic *in-situ* fluid saturation data was used as a history matching parameter to provide two-phase functions for the matrix. Fractures were modelled explicitly with exclusive two-phase functions to study sensitivities of fracture parameters. Both

fracture capillary pressure and fracture permeability impact displacement pattern and local recovery, and are shown to be important parameters to describe fluid flow in fractured reservoirs.

A fundamental study on the impact of boundary geometry during water imbibition into oil saturated strongly water-wet sandstone and chalk was performed. The commonly used all-faces-open boundary condition was compared to the two-ends-open boundary condition, where production from each end was collected separately. Results showed asymmetric oil production from each end. This undermines previous assumptions of strictly counter-current imbibition and can explain inconsistent scaling of imbibition experiments reported in the literature. Small scale heterogeneities on each of the end faces may be important factors in dictating direction of oil flow during spontaneous imbibition.

Experimental results and numerical simulations to characterize fluid flow in fractured carbonates provided the basis for studying two methods for enhanced oil recovery in oil-wet fractured limestone: 1) The ability of foam to divert flow from fractures to the matrix was studied experimentally. Foam is a well-known mobility control agent during gas injection in conventional, heterogeneous reservoirs, however, it is less studied for fractured reservoirs. Foam injection was compared to gas-, water- and surfactantfloods and injection of pre-generated foam was compared to foam generated *in situ* in the fracture system. Pre-generated foam injection was most efficient, with oil recoveries up to 80% OIP at high pore volume throughputs compared to less than 10% OIP by injection of gas, water or surfactant. 2) Reduction of fracture permeability by polymer gel was also studied. Polymer gels have very high resistance to flow and have been used for conformance control and water shut-off by the industry. The large 3D structures of the molecules prevent gels from entering the porous rock matrix. Polymer gel was injected directly into a fracture to reduce fracture permeability. A chase waterflood was performed to evaluate whether reduced fracture permeability by polymer gel diverted the flow away from the fracture and increased matrix sweep efficiency. Recovery increased by 15 % OIP during waterflooding when fracture permeability was reduced by polymer gel. *In-situ* saturation monitoring by X-ray computed tomography (CT) was used to track the saturation changes during gel and water injection.

Acknowledgements

I would like to thank the Norwegian Research Council for financial support to this thesis, which is part of the research project for enhanced oil recovery in heterogeneous carbonates.

I would especially like to acknowledge my supervisor Dr. Prof. Arne Graue for excellent guidance during my work and for providing a great environment for research and learning. I would also like to express my gratitude for having the opportunity to travel during my research. It has been fun!

I would like to thank my colleagues at the Department of Physics and Technology for academic discussions and good times. You all know who you are. I would especially like to thank my colleague Martin A. Fernø for collaboration and good collegial companionship.

Thanks to Dr. Prof. Henri J. Bertin for guidance, collaboration and a nice stay in Bordeaux. Thanks to Dr. Prof. Randy S. Seright at New Mexico Tech for valuable discussions on polymer gel and for showing me how to climb in Socorro. Thanks to Dr. Prof. Geoffrey Mason for discussions and a great time in Loughborough and Stanage.

Thanks to the staff at ConocoPhillips Research Centre in Bartlesville, Oklahoma for letting me work in their lab and making my stays both valuable and memorable. Special thanks to Dr. James J. Howard and Jim Stevens for guidance and assistance.

Thanks to Statoil Research Center for laboratory facilities and Lars Rennan and Ann Lisbeth Bye for guidance and assistance in the CT-lab.

Thanks to the Physics Department Mechanical Workshop by Kåre Slettebakken for excellent service and craftsmanship. It has been vital for my laboratory work. Thanks to Kåre Njøten for guidance and support with the Germanium detectors.

I thank my family and friends for genes and environment, whichever is more important.

Most importantly, I thank my girlfriend, Bergit, for love and for enduring a boyfriend that fades out on countless occasions. You make me happy!

List of Scientific Papers

1. Fernø, M.A., Ersland, G., **Haugen, Å.**, Graue, A., Stevens, J. and Howard, J.J.: *Visualizing Fluid Flow With MRI In Oil-wet Fractured Carbonate Rock*, Reviewed proceedings at International Symposium of the Society of Core Analysts held in Calgary, Canada, 10-12 September, 2007.

2. Haugen, Å., Fernø M.A., Bull, Ø. and Graue, A.: Wettability Impacts on Oil Displacement in Large Fractured Carbonate Blocks, accepted for publication in Energy & Fuels.

3. Haugen, Å., Fernø M.A., and Graue, A.: C*omparison of Numerical Simulations and Laboratory Waterfloods in Fractured Carbonates*, SPE 110368, proceedings at SPE Annual Technical Conference and Exhibition, Anaheim, California, USA, 11–14 November 2007.

4. Haugen, Å., Fernø. M.A., Graue, A**.:** *Numerical Simulation and Sensitivity Analysis of In-Situ Fluid Flow in MRI Laboratory Waterfloods of Fractured Carbonate Rocks at Different Wettabilities*, SPE 116145, proceedings at 2008 SPE Annual Technical Conference and Exhibition, Denver, Colorado, USA, 21 -24 September, 2008.

5. Mason, G., Fischer, H., Morrow, N.R., Johannesen, E., **Haugen, Å**,. Graue, A. and Fernø, M.A.: *Oil Production by Spontaneous Imbibition from Sandstone and Chalk Cylindrical Cores with Two Ends Open*, Energy & Fuels*, 2010, 24 (2), pp 1164–1169.*

6. Haugen, Å., Fernø, M.A., Graue, A and Bertin, H.J.: *Experimental study of foam flow in fractured oil-wet limestone for enhanced oil recovery*, SPE 129763 proceedings at SPE Improved Oil Recovery Symposium held in Tulsa, Oklahoma, USA, 24-28 April 2010.

1 Fractured Reservoirs

1.1 Introduction

Oil recovery from fractured reservoirs poses different challenges compared to oil production from conventional reservoirs. This introduction explains some of the challenges and considerations that are particularly important in fractured reservoirs and the efforts made to describe and predict oil recovery, fluid flow and enhance oil recovery.

Fractures are discontinuities in the rock appearing as breaks in the natural sequence of rocks and cause large contrast in capillary pressure between fractures and matrices. This is the main reason for the fundamental difference in recovery from fractured reservoirs compared to non-fractured reservoirs (Saidi, 1987, Firoozabadi, 2000). According to Bourbiaux (2009), designing a process to recover the matrix oil at an economic rate often turns out to be the real challenge for such reservoirs. In this thesis the impact from fractures and wettability on oil recovery in carbonates were investigated both experimentally and numerically and techniques for improved oil recovery were studied in fractured laboratory models.

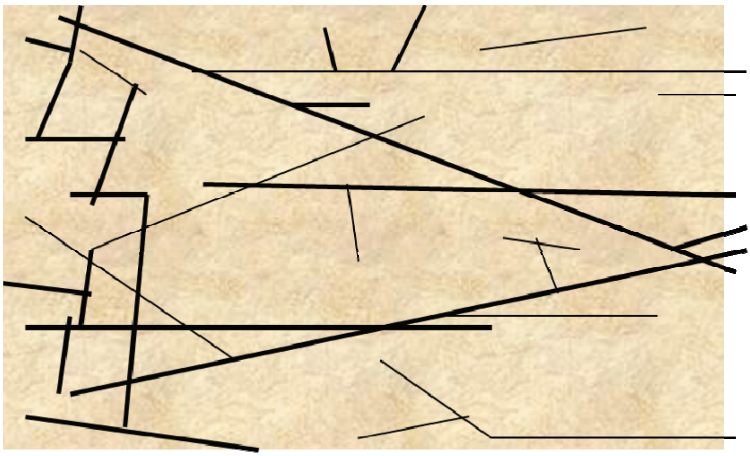

Figure 1: Sketch of smaller section of a fractured reservoir. Fractures of different orientations and widths surround matrix blocks. Some fractures are connected to a larger network of fractures, whereas others are isolated or dead-end fractures.

1.2 Classification of Fractured Reservoirs

Fractured reservoirs are heterogeneous reservoirs where matrix blocks are separated by fractures, **Figure 1**. Geological processes produce different types of fractured reservoirs, which may be classified in several ways. One common way of classifying fractured reservoirs was proposed by Nelson (2001). In Type 1 reservoirs, fractures provide both the essential permeability and porosity, exemplified by the Asmari Limestone fields in Iran where fracture pore volume range from 10-20% of the reservoir pore volume. Type 2 reservoirs are characterized by fracture dominated permeability, whereas the major part of the hydrocarbons resides in the rock matrix. North Sea chalk fields are examples of such reservoirs (Hermansen *et al.,* 2000). Type 3 reservoirs have fracture permeability that assists already producible reservoirs. In type 4 reservoirs, fractures provide no additional permeability or porosity, but create significant reservoir anisotropy. A slightly modified grouping was proposed by Firoozabadi (2000). In Group 1, the main hydrocarbon volume resides in the matrix and the fracture pore volume is very small. In group 2, the fracture pore volume constitutes between 10-20% of the total pore volume. In group 3 reservoirs, more than half of the hydrocarbons are stored in the fracture system with insignificant contribution from the matrix. This thesis focuses on reservoirs where oil recovery from the matrix is important, mostly associated with type 2 or group 1 reservoirs.

1.3 Characteristics of Fractured Reservoirs

Fractured reservoirs behave differently from conventional reservoirs during oil production. Some typical characteristics of fractured reservoirs according to van Golf-Racht (1982), are listed below:

- *Low producing gas-oil ratio*: The gas-oil-ratio is often substantially lower in fractured reservoirs compared to conventional reservoirs. High vertical communication in fractured reservoirs causes liberated gas to segregate towards the top of the reservoir.
- *Low pressure decline per unit oil produced*: The rate of pressure decline per unit of oil produced is normally low in fractured reservoirs compared to conventional reservoirs. This is caused by large supply of fluids from matrix to fracture as a result of gravity and imbibition combined with fluid expansion, segregation and convection. Conventional reservoirs must generally re-inject more than 80% of the produced gas to display similar rate of pressure decline per unit oil produced.
- *Lack of transition zone*: Fractured reservoirs often lack transition zones with sharp, horizontal fluid contacts. The fracture permeability is high, and changes in the fluid contacts are rapidly re-equilibrated even during production.
- *Small pressure drop around producing well:* High permeable fractures promote low pressure drops around producing wells even at high production rates.
- *Constant fluid properties with depth:* Compositional gradients are usually absent because fluids have been circulated by convection due to thermal expansion and compression. Conventional reservoirs always have varying bubble point as a function of depth.

2 Recovery Mechanisms in Fractured Reservoirs

Recovery mechanisms are different in fractured reservoirs compared to conventional, unfractured reservoirs. As stated above, the large contrast in capillary pressure between the matrix and the fractures is the main reason for the difference in recovery performance between fractured and conventional reservoirs (Saidi, 1987, Firoozabadi, 2000). This chapter focuses on important recovery mechanisms in fractured reservoirs, such as gravity drainage, spontaneous imbibition and the effect of capillary continuity between matrix blocks.

2.1 Gravity Drainage

Gravity drainage was first described by Cardwell and Parsons (1949) and is frequently an important mechanism of oil recovery in fractured reservoirs. Gravity drainage is a gas-oil displacement where gravity forces dominate over viscous and capillary forces, and may result in high oil recovery (Hagoort, 1980). Matrix blocks surrounded by gas are subject to gravity drainage if the gravity forces overcome the capillary forces. The gravity forces are determined by the density difference between the gas in the fracture and oil in the matrix, and the height of each matrix block. The effective height of the matrix block determines if gravity drainage will occur. If matrix blocks are short, the capillary threshold pressure will prevent recovery by gravity drainage. If matrix blocks are tall, gravity drainage may be an important recovery mechanism. The effective height of the matrix blocks increases if capillary continuity between matrix blocks is established. This is discussed further in section **2.4 Capillary Continuity.**

2.2 Spontaneous imbibition

Spontaneous imbibition, where water displaces oil from the matrix to the fracture by capillary forces, is an important recovery mechanism in fractured reservoirs. The large surface area open to imbibition in highly fractured reservoirs may provide economical production rates even in low permeability matrix reservoirs. Spontaneous imbibition of water is a direct function of the capillary and gravity forces, and depends on the pore system, the wettability (Zhou *et al.,* 2000), matrix-block sizes and shape (Mattax and Kyte, 1962), Zhang *et al.,* 1996, Ma *et al.,* 1997, Torsaeter and Silseth, 1985), the interfacial tensions (Karimaie and Torseter, 2007, Ma *et al.,* 1997), boundary conditions (Bourbiaux and Kalaydjian, 1990) and initial water saturation (Viksund *et al.,* 1998).

2.2.1 Capillary Pressure and Wettability

Capillary pressure is the controlling factor for spontaneous imbibition. Low capillary pressure in the fractures and high positive capillary pressure in the rock matrices drive the imbibition of water from fractures into the matrix. The capillary pressure is a function of pore structure, fluid properties, wettability and fluid distribution. Fluid distribution is controlled by fluid saturation and wettability. The efficiency of capillary imbibition in fractured reservoirs is thus strongly influenced by the wettability of the system (Zhou *et al.*, 2000). While clastic reservoirs are often considered water-wet, the majority of carbonate reservoirs are less water-wet or oil-wet, and capillary imbibition is suppressed or absent. In such reservoirs water will mainly flow through the fracture network rather than imbibing into the matrix, resulting in early water breakthrough and low oil recovery. The importance of wettability should not be underestimated, as wettability is the controlling factor for imbibition in fractured reservoirs.

2.2.2 Initial Water Saturation

The initial water saturation (IWS) in oil-water systems has been shown to influence ultimate oil recovery and rate of oil recovery during capillary imbibition. Imbibition rates decreased with increasing IWS in strongly water-wet Berea sandstone, whereas an opposite trend was reported for strongly water-wet chalks (Viksund *et al.,* 1998)). Maximum imbibition rate for chalk was observed at 34% IWS, ascribed to the net effect of reduced capillary pressure and change in relative permeability. Recovery was insensitive to IWS in Berea sandstone, however, ultimate recovery decreased with increasing IWS in chalk. Wettability also impacted the relationship between IWS and oil recovery. At strongly water-wet conditions, fractured chalk samples showed slightly decreased recovery with increased IWS during waterflood, but recovery increased with IWS at weakly water-wet conditions (Tang and Firoozabadi, 2001). The same observations were recently made in slightly water-wet limestone, where both the recovery and rate of recovery increased with increasing initial water saturation (Karimaie and Torseter, 2007).

2.2.3 Matrix Block Size

Matrix block size influences the recovery and performance of spontaneous imbibition in fractured reservoirs. Intensely fractured reservoirs provide large surface area open to imbibition and high rates of recovery may be obtained even in reservoirs with low matrix permeability. Recovery by spontaneous imbibition may be dramatically less efficient if matrix blocks are large and the surface area open to imbibition is small. The influence from gravity is determined by the height of the matrix block. Tall blocks promote gravity effects such as co-current imbibition, where oil is produced towards the top of the matrix block.

2.3 Capillary Continuity

Capillary continuity between matrix blocks is important during oil recovery from fractured reservoirs. Capillary continuity provides fluid communication between partially or completely isolated matrix blocks, thus increasing the ultimate recovery by gravity drainage and viscous displacement (Horie *et al.,* 1990, Labastie, 1990, Stones *et al.,* 1992). During gravity drainage, capillary continuity increases the effective height of the oil column to extend over several matrix block heights. This effectively allows gravity drainage to reduce oil saturations to lower residual oil saturation values than for single discontinuous matrix block gravity drainage, as shown in **Figure 2**. Vertical capillary continuity between matrix blocks also improved the predicted oil recovery by water displacement when modeling recovery from mixed-wet, fractured reservoir (Pratap *et al.,* 1997).

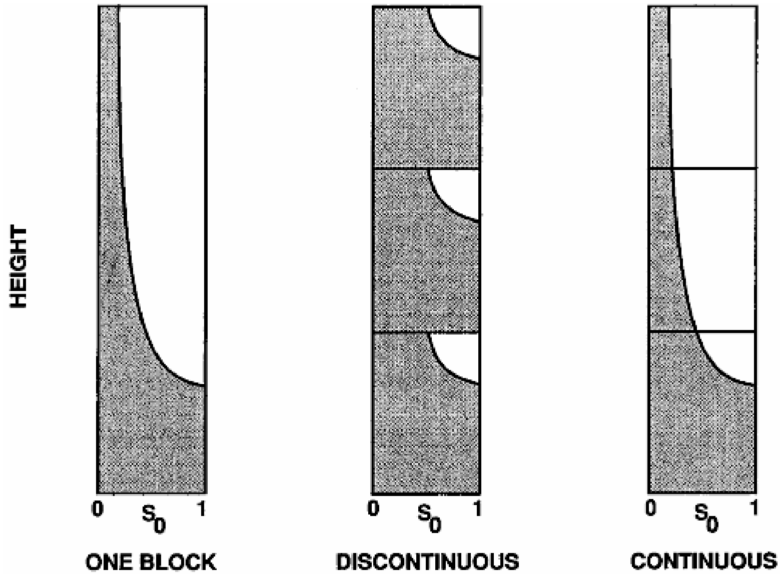

Figure 2: Effect of capillary continuity on ultimate oil recovery by Horie and Firoozabadi (1988).

2.3.1 Wetting Phase Bridges

A series of experimental results where fracture aperture and degree of contact between blocks were varied was reported by Firoozabadi and Markeset (1994). They observed that the mechanism of oil displacement from the matrix was in some cases the forming and breakdown of liquid droplets across an open fracture. Capillary continuity has been described for gravity drainage to be prevalent in the vertical direction, however, Rangel-German *et al.* (2006) observed that capillary continuity can occur in any direction, illustrating that the processes is not only gravity dominated. Capillary continuity during waterfloods by liquid bridges was observed by Graue *et al.* (2001a), Aspenes *et al.* (2002, 2007), using Magnetic Resonance Imaging to investigate flow across open fractures. At less water-wet states, capillary continuity was established by water droplets growing into liquid bridges that transported water across open fractures of up to 2.3 mm. At strongly water-wet conditions no capillary contact by liquid bridges was observed. The significance of wettability and fractures during waterfloods in larger blocks of chalk was investigated by Graue *et al.* (2000a, 2000b, 2001a, 2001b). They concluded that capillary continuity across fractures at less water-wet conditions transmitted differential pressure across the open fractures. This reduced the impact of the fractures and provided an additional viscous component across the individual matrix blocks. The viscous component compensated for loss in oil recovery by the reduced capillary imbibition and contributed to increased recovery of 10% pore volume above the potential for spontaneous imbibition (Aspenes *et al.,* 2007). At strongly water-wet conditions, the recovery was generally capillary dominated, and fractures were barriers to flow causing a matrix block-by-block displacement without capillary continuity. The controlling mechanisms of capillary continuity by liquid bridges were explained by contact angles at various wetting states. A strongly water-wet surface has a contact angle close to zero, causing water to spread as a film on the fracture surface. This inhibits the growth of water droplets and the fractures fill hydraulically. At less water-wet states the contact angle is larger, allowing water droplets to form and grow on the fracture surface during water injection. Depending on fracture width, wettability, differential pressure and interfacial tension, the droplets may attach across the fractures and establish capillary continuity by wetting phase bridges. Transmission of differential pressure and transport of wetting phase fluid across the fracture is thus possible. The mechanism for two different water-wet states is sketched in **Figure 3**.

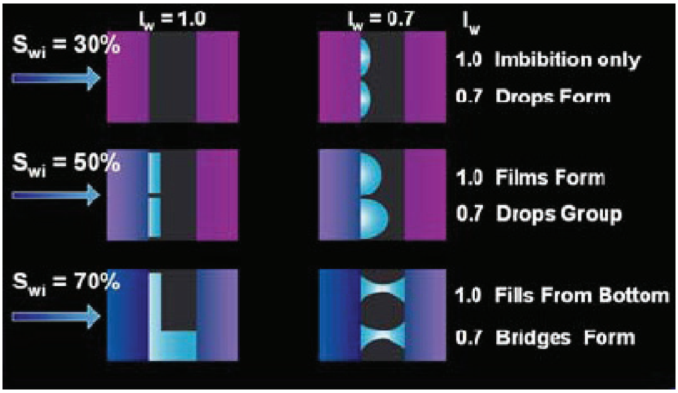

Figure 3: Proposed mechanism for fracture crossing from Aspenes *et al.* (2007). *Left*: Strongly water-wet state where a fracture fill hydraulically. *Right*: Droplet growth from bridges at moderately water-wet conditions.

3 Description of Fluid Flow in Fractured Systems

To improve oil recovery in fractured reservoirs it is important to understand the physical processes determining the interaction and fluid transfer between matrix and fracture (Gautam and Mohanty, 2004). This section focuses on description of flow in fractured reservoirs, in particular on scaling laboratory imbibition data. The effect of boundary conditions, fracture flow functions and fluid transfer between matrix and fractures during oil recovery is discussed briefly.

3.1 Scaling

The size of the matrix blocks in a reservoir is several orders of magnitude larger than matrix blocks in the laboratory. Imbibition data from laboratory tests must therefore be scaled to account for this size difference to be representative of reservoir imbibition behavior. Scaling of laboratory imbibition data have been proposed by several authors including Mattax and Kyte (1962), Zhang *et al.* (1996) and Ma *et al.* (1997). A widely used, semi-empirical scaling relationship based on the characteristic length, L_c ,was proposed by Ma *et al.* (1997), and is given by

$$L_C = \left(V_b / \sum_{i=1}^{n} \frac{A_i}{l_{Ai}}\right)^{0.5} \tag{1}$$

where V_b is the bulk volume of the core, A_i is the area open to imbibition in the ith direction, l_{Ai} is the length from the open face to the no-flow boundary, and n is the number of surfaces open to imbibition. The characteristic length normalizes spontaneous imbibition results performed with various boundary conditions. **Figure 4** shows four boundary conditions studied in the literature, where All-Faces-Open (AFO) is the most commonly used. Imbibition may be expressed by dimensionless time, t_D, to account for other variables including fluid viscosities, permeability, porosity and interfacial tension. The dimensionless time is given by

$$t_D = \frac{1}{L_C^2}\sqrt{\frac{K}{\varphi}}\frac{\sigma}{\sqrt{\mu_w \mu_{nw}}}t \tag{2}$$

where K is rock permeability, φ is porosity, σ is interfacial tension between the phases, μ_w and μ_{nw} is wetting and non-wetting fluid viscosities, t is the imbibition time and L_c is defined by equation (1). The dimensionless time may be used to compare imbibition for different boundary conditions with the assumption that flow is counter-current. In a more recent study, Li and Horne (2006) proposed an extended scaling that would account for parameters such as relative permeability, wettability, gravity and capillary forces.

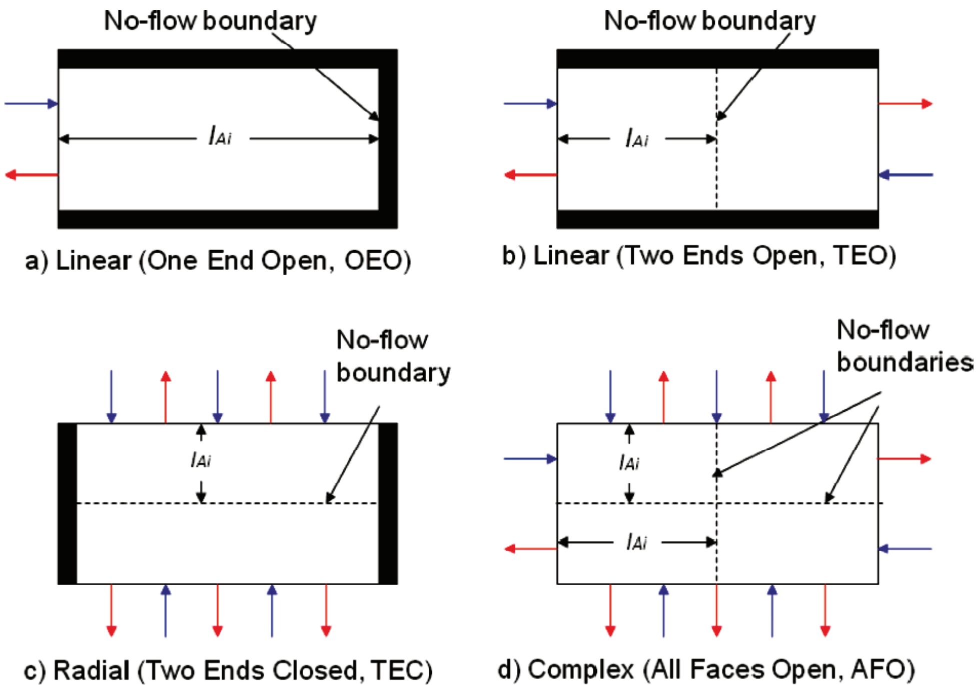

Figure 4: Counter-current imbibition for different boundary conditions including One-End-Open (OEO), Two-Ends-Open (TEO), Two-Ends-Closed (TEC) and All-Faces-Open (AFO). l_{Ai} is the distance between the surface open to imbibition and the no-flow boundary (Ma *et al.*, 1997).

3.1.1 Effect of Boundary Conditions

Laboratory imbibition experiments will in most cases result in counter-current flow conditions (Morrow and Mason, 2001), mainly because the core plugs are short and gravity forces are negligible compared to capillary forces, and the matrix boundaries are fully submerged in water at all times. Matrix blocks are generally far taller in fractured reservoirs, promoting co-current flow by gravity forces. Water drive will involve both counter-current and co-current flow in various portions of the reservoir depending on the magnitude of capillary to gravity forces (Bourbiaux, 2009). According to Pooladi-Darvish and Firoozabadi (2000) and Firoozabadi (2000), co-current imbibition prevails if parts of the matrix block surfaces are exposed to water, for example in gravity segregated fractures. Oil flow will preferentially be towards the boundary in contact with oil. Both co- and counter-current imbibition may coexist during waterfloods in fractured reservoirs (Karpyn *et al.,* 2009). The relationship between fracture flow rate and fracture/matrix transfer rate was experimentally verified to be a controlling factor for co- or counter-current imbibition in the matrix by Rangel-German and Kovscek (2002, 2006). Low fracture flow compared to the fracture/matrix transfer rate (*filling fracture* regime) occurred either by low injection rate, wide fractures or high imbibition rate into the matrix, and promoted co-current imbibition. In the *instantly filling* regime, fractures rapidly fill with water due to low fracture/matrix transfer rate, high injection rate or narrow fractures and imbibition is counter-current. Similar observations were made by Karimaie *et al.* (2006), where the recovery mechanism changed from co-current to counter-current when the boundary conditions changed from an advancing fracture water level to a fully water saturated fracture. Consequently, the mode of imbibition is sensitive to conditions at the boundary between fracture and matrix, including fracture saturation, speed of the rising water table and fracture flow rate compared to imbibition rate, which in turn are influenced by factors such as wettability, initial water saturation and matrix block size.

Experimental work and numerical models for different boundary conditions revealed that oil and water mobilities were lower during counter-current flow compared to co-current flow (Bourbiaux and Kalaydjian (1990)). Counter-current flow has lower mobile saturations (lower relative permeability) and higher viscous interaction between faces than co-current flow. Co-current imbibition is faster and have higher displacement efficiency than counter-current imbibition (Pooladi-Darvish and Firoozabadi, 2000, Unsal *et al.,* 2006, Karimaie *et al.,* 2006). Consequently, counter-current laboratory conditions may underestimate both rate and ultimate recovery when scaled to field conditions because of failure to capture the complexity of imbibition in fractured reservoirs.

3.2 Fracture Flow Functions

The simplest way of depicting a fracture is by two parallel plates separated by some aperture. Fracture permeability is then a function of the cube of the fracture aperture, also known as the cubic law (Witherspoon *et al.,* 1980). Fracture permeability in rough fractures does not always follow the cubic law (Lomize, 1951), especially if the fracture aperture is small compared to the roughness (Jones *et al.,* 1988). Fracture flow is also saturation dependent. Nevertheless, the fracture relative permeability and capillary pressure are often ignored or simplified in simulations of fractured reservoirs. A common simplification is to use linear fracture relative permeability curves with no irreducible saturations and set the fracture capillary pressure to zero.

3.2.2 Capillary Pressure in the Fracture

The capillary pressure difference between fractures and matrix have significant effect on recovery performance in fractured reservoirs (Firoozabadi, 2000). Romm (1966) found fracture capillary pressure to be zero in the aperture between two parallel glass plates. This is also the most commonly used assumption in reservoir simulation. The evidence of capillary continuity in fractured reservoirs, stated by Saidi *et al.* (1979), raised the question of capillary pressure in fractures. Horie *et al.* (1990) demonstrated that the fracture capillary pressure could not be constant and independent of saturation in stacked matrix blocks during gravity drainage. Firoozabadi and Hauge (1990) proposed that capillary pressure could be saturation dependent, similar to that of a porous medium, based on fracture aperture and roughness. The experimental data of fracture capillary pressure is very limited in the literature.

Assuming zero capillary pressure was incorrect in oil-gas systems if fractures were narrow, which was especially important if matrix block heights were small. Zero fracture capillary could, however, be used during water injection in water-oil systems (de la Porte *et al.,* 2005). Contradictory results reported by Rangel-German *et al.* (2006) found zero fracture capillary pressure to be incorrect for narrow fractures when simulating experimental waterfloods.

3.2.3 Fracture Relative Permeability

Flow in a fracture between smooth parallel glass plates was studied by Romm (1966). He found that relative permeability curves were straight line functions with relative permeabilities equal to the phase saturation. This is the most widely used input to numerical simulations of naturally fractured reservoirs, as few other data exist. Natural fractures are rough-walled, and Persoff *et al.* (1991) and Fourar *et al.* (1993) demonstrated experimentally that relative permeability was not linear with saturation in rough-walled fractures. Babadagli and Ershaghi (1992, 1993) stated that fracture relative permeability is not only a function of saturation, but also depend on flow velocity, permeability and capillary pressure of the matrix. They proposed an *effective fracture relative permeability* based on flow velocity and matrix properties such as wettability and initial water saturation. The viscosity ratio, capillary number and flow pattern were found to affect fracture relative permeability by Pan (2000). This was also supported by a recent analytical study by Shad and Gates (2010). Rossen and Kumar (1992) proposed to construct fracture relative permeability by a dimensionless fracture height based on the ratio between gravitational and capillary forces where the fracture capillary pressure curve was given by Firoozabadi and Hauge (1990).

The consequence and importance of fracture relative permeability curves on reservoir performance was demonstrated numerically by Rossen and Kumar (1994). They observed that fracture relative permeability can affect reservoir performance and sweep in much the same way as fracture permeability. Reduced relative permeability may improve sweep by increasing the pressure gradient relative to gravitational forces. More recently, de la Porte *et al.* (2005) indicated that using straight relative permeability curves could lead to oil recovery prediction errors up to 70% in numerical models of oil recovery by waterflood. The effect was more pronounced when fractures were narrow, fluid density differences were low and/or interfacial tension was high. Based on experimental results and simulations, Rangel-German *et al.* (2006) found that straight relative permeability curves could be used in some cases, but that relative permeability should not be equal to the phase saturation.

3.3 Transfer Functions

The transfer of fluids between matrix and fracture is important to model and predict reservoir oil recovery behavior. Fractured reservoir models are often conceptualized by dual porosity or dual permeability system. The dual porosity concept was first described by Barenblatt *et al.* (1960), and later introduced to reservoir engineering by Saidi (1975) and Kazemi *et al.* (1976) among others. In dual porosity systems, fluid flow and storativity occurs in two separate pore systems, equations for both fracture and matrix are solved and flow between the two systems is described through the transfer function with an upstream weighting scheme. The fracture relative permeability is then used to estimate the mobility or flow from the fracture towards the matrix and implies that when the water relative permeability is zero, no imbibition will occur. This is physically incorrect as matrix-fracture interaction is largely controlled by matrix flow properties (Wu *et al.,* 2004), and also impacted by flow velocity (injection rate) in the fracture(Babadagli and Ershaghi, 1993, Rangel-German and Kovscek, 2006). Gautam and Mohanty (2004) found that the fracture flow velocity influences the effective water saturation at the interface between fracture and matrix, and that fracture/matrix transfer is not linearly proportional to the effective water saturation at this interface.

4 EOR in Oil-Wet Fractured Reservoirs

The potential for enhanced oil recovery in oil-wet, fractured carbonates is large because large hydrocarbon reserves are retained in the matrix. The combination of capillary retained oil in the matrix due to oil-wet conditions and high permeable fracture networks that limit viscous forces, makes enhanced oil recovery challenging. Bourbiaux (2009) stated that designing a process to recover the oil stored in the matrix at an economic rate often turns out to be a real challenge for such reservoirs. Fractures constitute a small fraction of the reservoir, and relatively small amounts of chemicals to treat the fractures may provide large benefits to enhance oil recovery. This section focuses on EOR techniques relevant to fractured reservoirs.

4.1 Wettability Reversal

Changing the wettability of the matrix from oil-wet to water-wet promote recovery by spontaneous imbibition. One major challenge in the implementation of surfactant or additives in truly oil-wet reservoirs is forcing the injected fluids to contact and enter the matrix. Due to lack of viscous forces in fractured reservoirs, transport of additives from fracture to matrix in oil-wet matrices is dominated by diffusion and gravity forces. Diffusion is a slow process and oil recovery may thus be slow, especially if matrix blocks are large. Gravity effects are favored if the matrix blocks are tall.

4.1.1 Surfactants

Cationic and nonionic surfactants have been used to alter wettability towards more water-wet states in carbonates. Laboratory tests produced up to 70 % oil in place by spontaneous imbibition (Austad and Milter, 1997, Standnes *et al.,* 2002). Other types of surfactants may also alter wettability towards more water-wet states (Xie *et al,.* 2005, Spinler *et al.,* 2000, Chen *et al,.* 2001). Temperature is an important driving mechanism for any chemical process, and the efficiency of surfactant wettability reversal have shown to depend on elevated temperatures (Gupta and Mohanty, 2007).

4.1.2 Brine Composition

Improved oil recovery based on salt and ion concentration in the imbibing brine has recently gained interest. Low salinity brine flooding yielded increased recovery in sandstone (Tang and Morrow, 1997), and numerous studies on low salinity flooding have been published. Much attention has also been given to wettability alteration caused by ions in brine. The presence of Ca^{2+}, Mg^{2+} and SO_4^{2-} ions in brine have been reported to reduce oil-wetness in chalk and increase spontaneous imbibition. The presence of Ca^{2+} and Mg^{2+} alone was, however, not reported to alter wettability (Zhang and Austad, 2006, Strand *et al.,* 2006, Zhang *et al.,* 2007, Gupta and Mohanty, 2008). The presence of Mg^{2+} and SO_4^{2-} were also reported to decrease the oil-wetness at elevated temperature and increased oil recovery by 20-30 % (Karoussi and Hamouda, 2008). If the core initially contained either Mg^{2+} or SO_4^{2-} no added recovery was measured. The efficiency of the ions depends strongly on temperature and ions will only have an effect above some critical temperature (Zhang and Austad, 2006).

4.1.3 Thermal Stimulation

Thermal stimulation may also alter wettability of a reservoir. Wettability was reported to shift from intermediate wet to strongly water-wet with increasing temperature in laboratory imbibition studies of diatomite reservoir rock (Schembre *et al.* (2006)). Elevated temperatures by steam caused initially neutrally- or oil-wet cores from the Quarn Alam field in Oman to imbibe water with recovery of 27 -35 % (Al-Hadhrami and Blunt (2001)).

4.2 Interfacial Tension Reduction

Reduced interfacial tension (IFT) between the aqueous phase and the oil phase by use of surfactants may reduce residual oil saturations and increase ultimate oil recovery. It also promotes influence from gravity. In strongly water-wet media, Babadagli *et al.* (1999) demonstrated that lowering the IFT by surfactants could increase the recovery, but the rate of recovery decreased because of weaker capillary forces at low IFT. In a weakly water-wet limestone, Karimaie and Torseter (2007) observed an increase in oil recovery by lowering the IFT, because increased gravity effects promoted co-current flow. Enhanced gravity effects in oil-wet matrices could contribute to higher recovery. Karimaie and Torsæter (2010) recently reported that gas-oil gravity drainage at low interfacial tension resulted in very efficient recovery from low permeable chalk at water-wet conditions. They also observed that re-pressurization by gas injection increased the oil recovery as a result of lowered IFT between oil and gas at high pressures.

4.3 Foam

Foam in porous media is defined as a dispersion of gas in a liquid such that the liquid phase is continuous, and at least some part of the gas is made discontinuous by thin liquid films called lamellae (Hirasaki, 1989). Foam has been recognized as a promising agent for controlling gas mobility in EOR processes in heterogeneous reservoirs (Bernard and Holm, 1964, Holm, 1968). A favorable property of foam in heterogeneous porous media is that foam generation will occur in the high permeable zones first, diverting the fluid flow to less permeable zones. This property was confirmed by Casteel and Djabbarah (1988) when injecting CO_2 and surfactant in parallel Berea cores with a permeability ratio of 6.4. Foam generation was dominant in the high permeable core, diverting the injected CO_2 towards the low permeable core. Others (e.g. Llave *et al.* (1990) and Zerhboub *et al.,* 1994) made similar observations. When capillary contact and cross-flow between heterogeneous zones occurred, foam moved with equal velocity in the low permeable and high permeable region (Bertin *et al.,* 1999). This may be important for fractured systems, where large permeability contrasts exists and cross-flow between the zones occur.

Oil recovery during CO_2-foam injection in fractured chalk at reservoir conditions was recently studied by Fjelde *et al.* (2008), Zuta and Fjelde (2009) and Zuta *et al.* (2009). They demonstrated that CO_2-foam improved the sweep and increased the recovery rate and the total oil recovery in low permeable chalk. CO_2-foam blocked the fracture by reducing mobility and increasing effective viscosity. It should be noted that the permeability contrast between the fracture and matrix was controlled by glass beads in the fracture, hence, essentially acting as two porous media with a large permeability contrast similar to Bertin *et al.* (1999).

Foam flow in rough-walled fractures was characterized by Kovscek *et al.* (1995), using a transparent fracture with an average aperture of 30 μm in granite (zero matrix permeability). Mobility reduction factors between 100-540 for foam flow in fractures were reported. The sweep efficiency in a fracture with variable aperture was greatly improved when injecting foam (Yan *et al.,* 2006). The apparent foam viscosity was found to be largely controlled by the number of bubbles (lamellae) per unit length. The resistance increased with the number of lamellae, implying that for a given bubble size, the apparent foam viscosity is lower in small aperture fractures than in large aperture fractures. This may be important because the resistance to flow then increases more in large aperture fractures than in small fractures.

4.4 Permeability Reduction

Mobility control of the fluid flow in the fracture network is one way of diverting fluids into other parts of the reservoir. According to Matthäi (2009), fluid flow in fractured reservoirs is focused into the most well-connected fracture networks, leading to very low sweep of the matrices. Reduction in fracture permeability was verified to have great impact on waterflood oil recovery in moderately water-wet chalk by Graue *et al.* (2002). Reduction of flow in the largest, most connected fractures may increase sweep and promote oil recovery by viscous forces. Controlling fracture permeability is thus one way of contributing to enhanced oil recovery from fractured reservoirs. This section will describe some of the techniques used to reduce channeling or fracture permeability.

4.4.1 Polymer Gels

Polymer gels are crosslinked polymer solutions of large molecular structure that prevents penetration into the porous rock matrix (Seright *et al.,* 2001) and only propagate through fractures to reduce their permeability. Polymer gels are non-Newtonian (shear-thinning) fluids with a high resistance to flow and has been successfully implemented for water shut-off in several oil producing fields (Sydansk and Moore, 1992, Sydansk and Southwell, 2000, Seright *et al.,* 2001). Approximately 1400 polymer gel applications have been reported worldwide since 1989 (Willhite and Pancake, 2008). Polymer gels have also been investigated to reduce channeling in naturally fractured reservoirs (Seright, 1997, Seright and Lee, 1999), thereby diverting injection fluids to unswept areas. Gel treatment is most efficient when fractures are aligned with the direction of flow between injector and producer (Seright and Lee, 1999). Increased resistance to flow may promote viscous forces across the fracture network and allow higher degree of viscous flooding if gel injection is followed by water injection. Polymer gels cannot be injected deep into the reservoirs due to its viscous nature. Therefore, gels are often injected before the gelation process as less viscous gelant. When gelant progresses into a reservoir, the temperature increases, thereby initiating the gelation process where gelant forms into gel. As the gel forms it essentially becomes immobile. At the current state of the art, gelants have relatively short gelation times (hours). This limits the in-depth penetration of the polymer gel, because the formed gel is immobile for all practical purposes. Recently, Cordova *et al.* (2008) presented the use of polyelectrolyte complex nanoparticles to entrap and control the release of cross-linking agent and effectively increase the gelation time in for polymer gels from 30 minutes to several days.

4.4.2 Polymer-Enhanced Foam and Foamed Gel

Foam and polymer have been used together providing combined benefits. Polymer-enhanced foams have higher stability and very high effective viscosity compared to regular oil recovery foam (Sydansk, 1994). It may plug and divert fluid flow away from a high permeability zone. Foamed gels can be used to plug high permeable zones for diversion (Miller and Fogler, 1995). The foamed gels are crosslinked polymers with an added surfactant that foams with gas. One advantage of a foamed gel is that it reduces the amount of expensive polymer and provides increased mechanical stability to the foam. It is therefore better suited for long term water diversion compared to aqueous foam that quickly looses integrity when subjected to waterflooding.

4.4.3 Microbial Permeability Reduction

Reduction of fracture permeability by bacterial growth has also been suggested by Han *et al.* (2001), Zekri and El-Mehaideb (2002). They showed that bacterial growth may increase the resistance to flow in the fracture and thus divert injected water to other parts of the reservoirs. They reported improved oil recovery by between 6 and 10% OOIP when reducing permeability by microbial treatment.

5 Results & Discussion

This chapter discusses the results and findings of the six scientific papers included in this thesis. The first part of this thesis focused on describing fluid flow in fractured systems at different wettabilities. Complementary imaging of *in-situ* fluid saturation development was used to better describe the mechanisms that control fluid flow. **Paper 1** is a study of fluid flow across open fractures during water- and oilfloods in stacked core plugs at strongly water-wet and moderately oil-wet conditions. High spatial resolution magnetic resonance imaging was used to monitor matrix and fracture saturation development simultaneously. In **Paper 2 - 4,** larger blocks of carbonate rock were used to investigate the wettability effects on waterflooding with and without a fracture network present. Waterflooding was first performed on a whole block, the block was then drained back to initial water saturation, fractured and reassembled before a second waterflood was performed. This isolated the impact from fractures at each wettability condition. Wettabilities ranged from strongly water-wet (I_{AH} = 1.0) to weakly oil-wet (I_{AH} = -0.2) conditions. During all waterfloods the samples were imaged by either Magnetic Resonance Imaging (MRI) or Nuclear Tracer Imaging (NTI). In **Paper 2** and **Paper 3** dynamic *in-situ* fluid saturation data was used to history match waterfloods of whole rock samples by numerical simulations. This provided matrix relative permeability and capillary pressure curves. Fracture networks reflecting the experimental laboratory rock samples were then put explicitly into the history matched numerical models, and numerical simulations were used to investigate the impact from fracture properties. **Paper 5** presented experimental work on spontaneous imbibition with the boundary condition known as Two-Ends-Open (TEO) and indicated that the properties of the fracture surface impact fluid flow.

The second part of the thesis focuses on techniques to enhance oil recovery in fractured systems. **Paper 1-4** identified the impact from fractures on waterflood oil recovery, concluding that fracture permeability was important, especially at oil-wet conditions in limestone. Two EOR techniques were tested in oil-wet, fractured limestone. **Paper 6** presents foam injection and compared foam injection to water-, gas- or surfactantflood. Work in progress on the use of polymer gel injection to reduce fracture permeability is also discussed.

5.1 Fluid Flow in Fractured Carbonates

The fluid flow within fractures influences the transfer of fluids between the fracture and the matrix. This section discusses the influence from wettability on the fluid flow inside fractures and how this affects transfer of fluids to the matrix. **Paper 1** is a mechanistic study of fluid transfer across open fractures at strongly water-wet (I_{AH} = 1.0) and moderately oil-wet (I_{AH} = -0.4) conditions in Edwards limestone. MRI was used to monitor the development in fracture and matrix fluid saturations during oil- and waterfloods in stacked core plugs separated by a 1mm open fracture. **Paper 2** scales up and increase fracture complexity by using larger blocks. The results illustrated the impact from wettability and how the relationship between capillary and viscous forces changed for different wettability conditions. The blocks were first waterflooded at whole state from irreducible water saturation, then drained back to the same irreducible water saturation, cut by saw and reassembled, before a second waterflood was performed. This isolated the effect from fractures at each wettability condition. The fractured blocks are sketched in **Figure 5.** Magnetic Resonance Imaging (MRI) or Nuclear Tracer Imaging (NTI) was used to obtain the *in-situ* fluid saturation developments during fluid flow. Details on MRI and NTI are found in Ersland *et al.* (2008).

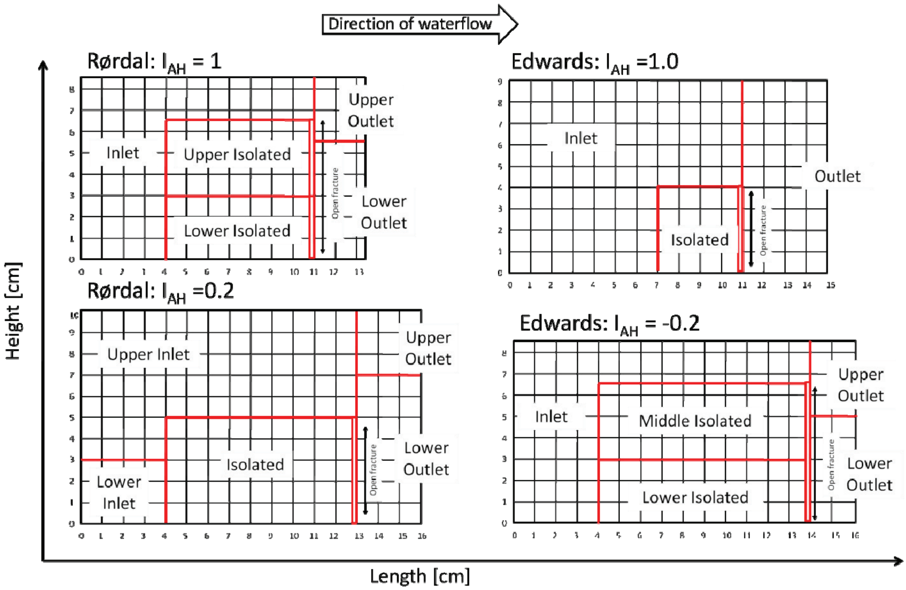

Figure 5: Schematics of the blocks with corresponding Amott-Harvey wettability indices as presented in **Paper 2**. Red lines indicate the position and outline of the fracture networks. The direction of flow during waterfloods allow flow perpendicular and parallel to the fractures.

5.1.1 Rock Types - Extending the Wettability Conditions

It was important to study oil-wet conditions because carbonate oil reservoirs commonly display oil-wet behavior. Fluid transfer in fractured rock models for various water-wet (I_{AH}>0) conditions during waterflood was studied in Rørdal chalk by Graue et al. (2001a), Aspenes et al. (2002, 2007), see section **2.3.1 Wetting Phase Bridges**. The Edwards limestone outcrop rock was used to extend the study to oil-wet conditions as the Rørdal chalk may only be aged to various water-wet conditions with the current crude oil/brine/rock system (Graue *et al.,* 1999). Edwards limestone was aged by crude oil to moderately oil-wet conditions (**Paper 1**: I_{AH} = -0.4) and weakly oil-wet conditions (**Paper 2:** I_{AH} = -0.2). Strongly water-wet baseline samples were also prepared. The brine permeability and porosity ranged from 3-28 mD and 16-24% for Edwards limestone. Rørdal chalk was used for water-wet conditions prepared at strongly water-wet (I_{AH}=1.0) or aged to weakly water-wet (I_{AH} = 0.2) conditions. The brine permeability and porosity ranged between 1-4 mD and 45-48% for Rørdal chalk. Rørdal chalk is sometimes referred to as Portland chalk.

5.1.2 Strongly Water-Wet Conditions

Waterflood oil recovery at fractured state was similar compared to whole state at strongly water-wet conditions for both Rørdal chalk and Edwards limestone(**Paper 2**). This was the consequence of high capillary pressure with a strong affinity to water in both the Rørdal Chalk and the Edwards Limestone. The presence of fractures did not impact recovery by more than a few percent of OIP, but *in-situ* data revealed that the fractures dictated the flow pattern during waterflood. The injected water did not escape the matrix until the endpoint for spontaneous imbibition was reached. *In-situ* images identified that oil in the matrix was displaced co-currently, resulting from high capillarity matrix combined with low injection rate similar to *the filling regime* proposed by Rangel-German and Kovscek (2002). The observations made corroborate **Paper 1.** This behavior is attributed to the discontinuity in the capillary pressure at the matrix/fracture interface, where injected water is trapped in the rock matrix until capillary pressures at the interface between the matrix and the fracture are equal. The fractures had low capillary pressure close to zero, whereas the oil saturated matrix was at high positive capillary pressure. At strongly water-wet conditions, the matrix capillary pressure becomes zero at residual oil saturation, thus water will not enter fractures until the matrix saturation is close to residual oil saturation at the end point for spontaneous imbibition. Consequently, block-by-block displacement, where each matrix block imbibed water close to the endpoint for spontaneous imbibition, was observed. Both papers demonstrated that fractures were capillary barriers to flow at strongly water-wet conditions and that the recovery was dominated by capillary forces. There was no apparent capillary continuity across the open fracture for either oil- or waterflooding in **Paper 1.**

5.1.3 Weakly Water-Wet Conditions

At weakly water-wet states, the potential for spontaneous imbibition was reduced and viscous forces were needed to compensate for oil recovery above this potential. This was demonstrated in **Paper 2** at weakly water-wet (I_{AH} = 0.2) chalk using NTI. The presence of interconnected, high permeability fractures limited the viscous forces during waterflooding, reducing oil recovery from 66% to 22% OIP compared to whole state. Slow capillary imbibition resulted in rapid filling of the entire fracture network and early water breakthrough. Oil was recovered by counter-current capillary imbibition of water from the fractures to the matrices with a long transient production. Reduction in fracture/matrix transfer rate at weakly water-wet conditions increased the likelihood of the *instantly filled fracture* regime (Rangel-German and Kovscek, 2002) associated with counter-current imbibition.

5.1.4 Oil-Wet Conditions

Paper 1 and **Paper 2** illustrated the impact from fractures during waterfloods at oil-wet conditions. The oil-wet conditions presented in these papers had zero potential for spontaneous imbibition of water. Waterflooding a stacked, moderately oil-wet core plug identified a capillary threshold pressure of almost 3.4kPa (0.5 psi) for water to enter the oil-wet matrix. **Figure 6** shows the observed pressure build-up in the fracture to coincide with water entering the downstream core plug.

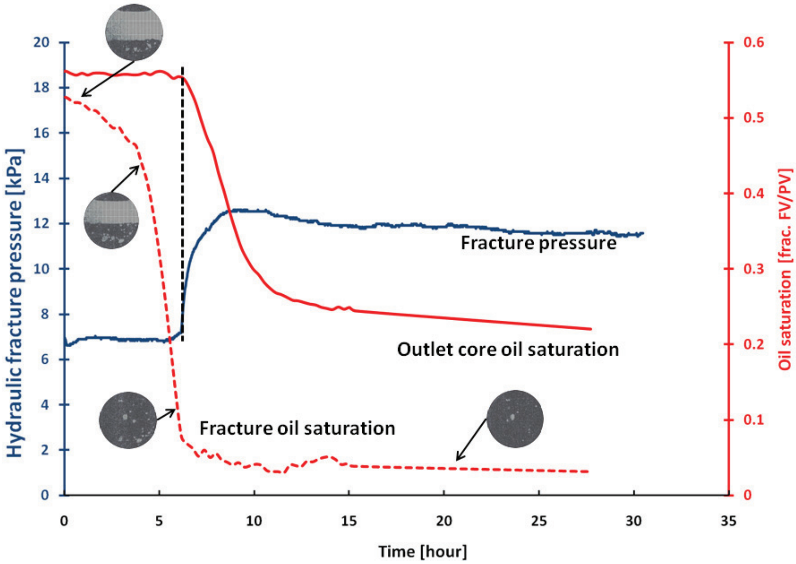

Figure 6: Saturation and pressure development in an oil-wet core plug. Fracture saturation and pressure and downstream matrix block saturation. The rapid increase in fracture pressure from 3.4 kPa (0.5 psi) coincided with water entering the downstream matrix block.

The fractures in the stacked core-plugs in **Paper 1** were perpendicular to the direction of flow with no alternate flow path for the injected water to escape, thus forcing the injected fluids across the fractures and into the rock matrices. In naturally fractured reservoirs, fracture orientation vary and flow along the fracture orientation will occur. The block fracture networks in **Paper 2** allowed water to flow around the matrix blocks. The *in-situ* data revealed that injected water escaped through the fracture network without any transfer of fluids from fracture to matrix at weakly oil-wet conditions. The high permeable fractures limited the contribution from viscous forces, significantly reducing oil recovery compared to the waterflood of the sample without fractures.

Oilflooding at moderately oil-wet conditions established capillary continuity in the oil phase, and injected oil was transported across the fracture through capillary pressure contacts. This corroborated the similarity between water bridges during waterfloods at moderately water-wet conditions in chalk (Graue *et al.,* 2001a). This supports that the wettability of the fracture surface is the controlling factor for establishing liquid bridge capillary continuity across fractures.

5.2 Simulating Flow in Fractured Rocks

Numerical simulations were used to extend the study beyond the experimental results and perform sensitivity studies. Simulators may also assist in the interpretation of experimental observations. **Paper 1**, **Paper 3** and **Paper 4** included numerical simulations to study variations in fracture properties such as fracture permeability and fracture capillary pressure. In **Paper 3** and **Paper 4** a commercial black oil simulator (Eclipse100, 2007) was used to build a numerical representation reflecting the experimental conditions in whole and fractured block samples. The Sendra (2007) core flood simulator was used to numerically represent oil- and waterfloods in stacked core plug systems in **Paper 4**.

5.2.1 History Matching Laboratory Waterfloods

Validating the numerical models by history matching the experimental results is important for reliable predictions. The experimentally observed *in-situ* fluid saturation development from waterfloods of whole systems was matched numerically in **Paper 3** and **Paper 4**. Capillary pressure and relative permeability curves measured on similar core material were tuned to reflect the *in-situ* saturation development. This provided the matrix capillary pressure and relative permeability functions and was left fixed when a good match was obtained. The fractures were then explicitly put into the numerical model, with exclusive permeability, relative permeability and capillary pressure data. Only the fracture representation was changed in the subsequent simulations. **Paper 1** used Sendra (2007) core flood simulator with an automated procedure to determine two phase functions (relative permeability and capillary pressure) based on history matching differential pressure and saturation development.

5.2.2 Capillary Pressure in the Fracture

The capillary continuity was verified to impact recovery during waterfloods (Graue *et al.,* 2000a, 2000b, 2001a, 2001b). **Paper 3** addressed capillary pressure in the fractures of an embedded fracture network in a strongly water-wet Edwards Limestone sample. The experimental *in-situ* data revealed that one isolated block did not imbibe water to displace oil. This was highly unexpected for a strongly water-wet, high capillarity medium. Simulation with zero capillary pressure in the fractures failed to predict this fluid saturation development. Saturation dependent capillary pressure curves based on Firoozabadi and Hauge (1990), was assigned to the different fractures in the model. This created varying degree of capillary continuity across the different fracture surfaces, and reproduced the experimental observations successfully. The fracture capillary pressure was several orders of magnitude lower than the matrix capillary pressure.

Paper 4 addressed capillary pressure in a well-connected fracture network in a weakly oil-wet Edwards Limestone sample. The high connectivity of the fractures reduced the impact by fracture capillary pressure. The lowest recovery was predicted when using the capillary pressure curve reflecting the highest positive capillary pressure values; i.e. water-wet curves. At positive capillary pressure in the fracture, the injected water had a slightly higher preference to remain in the fracture rather than entering the oil-wet matrix. The highest recovery occurred with negative capillary pressure values; i.e. oil-wet conditions. At negative capillary pressure in the fracture, water had slightly less preference for flowing in the fracture and a small portion of the injected water entered the matrix. The effect of changing the capillary pressure in the fracture was small and recoveries only ranged by a few percent of OIP.

The open 1 mm fractures in **Paper 1** suggested zero capillary pressure in the fracture. The transport of oil across the fracture by capillary continuity during oilflooding was, however, not captured by assigning zero capillary pressure to the fracture. A linear capillary pressure with negative values, ($P_c(S_w=0)=0kPa$) to $P_c(S_w=1.0)=-6kPa$), was needed to more accurately reproduce the saturation development across the fracture. Fracture relative permeability also influenced the transport of oil, although not to the same extent as fracture capillary pressure.

The literature on fracture capillary pressure is limited and zero capillary pressure is the most common assumption. The results presented here revealed that capillary pressure in the fracture could be an important parameter to predict recovery, and corroborates that zero capillary pressure in the fracture may be incorrect (Rangel-German *et al.,* 2006). In high permeable fractured systems, however, oil recovery was insensitive to the fracture capillary pressure and a zero capillary pressure was found to be adequate. Capillary continuity by liquid bridges could be captured by a simple, linear capillary pressure relation to saturation. Consequently, the impact from fracture capillary pressure depends on the fracture network.

5.2.3 Fracture Permeability

The influence of fracture permeability on waterflood oil recovery was numerically investigated at strongly water-wet and oil-wet conditions in **Paper 4.** The results indicated that the wettability of the rock was a controlling parameter for the oil recovery at different fracture permeabilities. At strongly water-wet conditions, fracture permeability had no effect on oil recovery, i.e. displacement was capillary dominated and determined by the potential for spontaneous imbibition. At oil-wet conditions, the recovery was insensitive to fracture permeability at high values, as this did not promote significant viscous forces for recovery. Ultimate recovery was sensitive to fracture permeability values below 20 times the matrix permeability. This corroborated similar results in fractured moderately water-wet chalk (Graue *et al.,* 2002). Low fracture permeabilities promote higher viscous forces at a given rate, thus displacing a larger portion of oil by viscous forces. The number 20 is an arbitrary number as it is the net effect of the capillary forces and viscous forces that determine the recovery. Higher injection rates or increased viscosity of the injected fluid would also promote recovery by viscous forces. This was of special interest in terms of EOR, because plugging of the high permeable fractures could improve the viscous contribution during waterflooding.

5.3 Spontaneous Imbibition with TEO Boundary Conditions

Spontaneous imbibition is an important recovery mechanism in fractured reservoirs, and counter-current flow is the dominant mode of imbibition (Morrow and Mason, 2001). During counter-current imbibition experiments, it is often assumed that flow rates of brine and oil are equal and in opposite directions. **Paper 5** presents spontaneous imbibition experiments using cores with the Two-Ends-Open (TEO) boundary conditions. Inconsistencies in the recovery times by scaling the imbibition to dimensionless time by Ma *et al.* (1997) using equations (1) and (2) was observed. The study included a setup to measure the oil production from each of the open end faces separately. Initial oil was produced from both end faces, however, in most cores the oil production slowed down and in some cases stopped on one of the end faces. Consequently, oil production was asymmetric in the later stage, and significantly more oil was recovered from one end face than the other. This occurred in both homogenous Berea sandstone and Rørdal chalk. Increasing asymmetry in production from each end phase was associated with overall slower imbibition rates. Imaging of the imbibition revealed that the imbibing water front was relatively symmetric, even with asymmetric oil production. This indicated that there was a net inflow of water at one side and a net outflow of oil at the opposing side of the core, i.e. true counter-current flow was not always the case for TEO boundary conditions.

The symmetric water front advancement in the chalk suggested that most of the pressure drop was dissipated in the invading water phase and not in the oil phase. If the pressure drop in the oil phase is small, minor inhomogeneities at different sides may dictate the direction of flow of oil after the initial true counter-current stage. The oil has to overcome the capillary back pressure at the outlet face. This back pressure is set up because the production mechanism at the open end faces is similar to a drainage process and is determined by the largest pores at the surfaces where oil is produced as droplets (Li *et al.,* 2006). Even though capillary back pressure difference between the two end faces is small, it can be a large fraction of the low pressure driving the flow of oil. At the same time water is less affected by small changes in the capillary back pressure and the water front remains symmetrical. Consequently, small inhomogeneities in a rock may have a disproportionately large effect on the recovery and flow of oil. This illustrates that properties of the boundary between fracture and matrix have significant impact on flow between fracture and matrix.

5.4 Enhanced Oil Recovery

The potential for enhanced oil recovery is large in many naturally fractured reservoirs. Oil-wet fractured reservoirs pose particular challenges because oil in the matrices is retained by capillary forces. This section presents and discusses laboratory results from enhanced oil recovery efforts in fractured, oil-wet limestone. **Paper 1-4** characterized flow in fractured carbonates, and identified challenges related to oil recovery. Wettability was the main controlling factor for waterflood oil recovery in the presence of fractures. At oil-wet conditions, waterflood oil recovery was particularly low, as no transfer of fluids from fracture to matrix was observed. Numerical prediction in **Paper 4** found that resistance to flow could be increased by reducing the fracture permeability leading to increased recovery because of higher viscous forces. A capillary threshold pressure for water to enter the oil-wet matrix was identified in **Paper 1**. The threshold pressure must be overcome for water to displace oil from the matrix. Enhanced oil recovery could be achieved by increasing the resistance to flow in fractures to divert fluids into the matrix by viscous forces. **Paper 6** investigated if foam could reduce flow in the fractures and divert fluids into the matrix for additional oil recovery. Another approach investigated if polymer gel could plug and reduce the permeability of a fracture. The water pressure would then increase in the subsequent waterflood, diverting water into the matrix for increased oil recovery. The polymer gel treatment is work in progress.

5.4.1 Foam in Fractured, Oil-Wet Limestone

Paper 6 investigated whether foam injection in a fractured oil-wet limestone would enhance oil recovery. Foam is well-known to reduce the mobility of gas and increase resistance to flow (Bernard and Holm, 1964, Holm, 1968, Rossen, 1995).The literature on foam in fractures is limited, especially in fractured, porous rocks. Foam may exhibit high resistance to flow, and has been shown to reduce flow more in high permeability layers, than in low permeability layers (Bertin *et al.,* 1999). The apparent viscosity of foam is larger in large aperture fractures compared to small aperture fractures (Yan *et al.,* 2006). **Paper 6** investigated foam generation and foam injection efficiency in oil-wet, fractured limestone blocks and core plugs similar to those presented in **Paper 1-4**. The foam injection was compared to water, gas or surfactant injection, and injection of pre-generated foam was compared to generation of foam directly in the fractures. Foam consisted of an Alpha Olefin Sulfonate (AOS) surfactant mixed in a brine solution together with Nitrogen (N_2) gas.

<u>Foam Generation in Fractures</u>

Foam is mainly generated by three mechanisms: leave-behind, snap-off and lamella division. Foam generation by leave-behind generally occurs below some critical gas velocity, creating weak and coarse foam (Ransohoff and Radke, 1988). Foam generation by snap-off is widely recognized to generate the strongest foam, with a discontinuous gas phase and the highest resistance to flow. Generation by snap-off is strongly linked to the porous media and the aspect ratio, i.e. pore body radius must be significantly larger than pore throat radius (Ransohoff and Radke, 1988). The results from **Paper 6** indicated very poor generation of foam in the fracture because the criterion for snap off was not met in the relatively smooth and polished fracture surfaces. In a smooth fracture, cut by saw, the number of snap off sites would be low, and foam generation by snap-off would be negligible. Natural fractures are generally more rough-walled and significant foam generation by snap-off could occur here (Kovscek *et al.,* 1995).

Foam Stability

The stability and generation of foam also depend on wettability, and strong foam by snap-off is more dominant in water-wet media. Foam has been generated in an oil-wet, porous medium, but foam efficiency was reduced by the presence of oil (Sanchez and Hazlett, 1992). The generation of foam was also reduced at intermediate wetting conditions compared to water-wet states (Schramm and Mannhardt, 1996). In the presence of oil, the entering coefficient should be negative for oil-tolerant foam to prevent destabilization of the foam (Bergeron *et al.,* 1993). This was, however, not the case in **Paper 6**. The destabilization of foam inhibits foam front movement (Bernard and Jacobs, 1965, Jensen and Friedmann, 1987). The injection of pre-generated foam in **Paper 6** showed that foam changed its configuration during injection, as limited amounts of foam were observed at the outlet. The combination of wettability and presence of oil (decane) caused reduced stability of the injected foam. The pressure build-up during foam injection suggested that foam gradually became more stable over time as oil was produced.

Oil Recovery by Foam Injection

Injection of pre-generated foam was found to be the most efficient recovery method when compared to water-, gas- or surfactant injection at comparable volumetric flow rates. Pre-generated foam produced significantly higher differential pressure drops indicating larger resistance to flow, and was a key factor for the enhanced oil recovery in these fractured systems. It corroborated **Paper 4**, showing that increased flow resistance in the fracture yielded significantly higher sweep and increased recovery. Recovery was reported up to almost 80%, and the injection of pre-generated foam significantly increased recovery for all samples. The rate of recovery increased with decreasing fracture/matrix permeability ratio, defined as the permeability after fracturing divided by the permeability before fracturing, and illustrated the need for well-described fracture systems to predict the oil recovery. The fastest recovery scaled to PV injected was observed at low fracture permeability, however, between 40 and 200 pore volumes were injected until ultimate recovery was reached. This may be unrealistic compared to most field cases. The relationship between rate of recovery and fracture/matrix permeability ratio needs to be further investigated.

Waterflooding high permeable, fractured, oil-wet rocks in **Paper 6** resulted in limited pressure drops and inefficient oil recovery from the matrices, similar to the observations in **Paper 2** and **Paper 4**. The waterfloods mainly recovered oil from the fracture, leaving the matrix unswept due to a water capillary threshold pressure. Similarly, the lack of pressure build-up and the gas threshold pressure limited oil production during gasfloods. The threshold pressure was significantly reduced during the AOS surfactantfloods due to lowered interfacial tension between surfactant solution and decane (<< 5 dynes/cm). Because the flow resistance to surfactant solution remained low, only minor recovery was observed during surfactant injection. The *in-situ* generation of foam in the fractured samples was inefficient and no observations of foam generation or oil production were made. The lack of pressure build-up during injection suggested that the resistance to flow did not increase and that no foam was generated in the fracture.

5.4.2 Fracture Permeability Reduction by Polymer Gel

A polymer gel (Cr(III)-Acetate-HPAM) was used to reduce the fracture permeability to increase the sweep in a subsequent waterflood. This would determine if fracture permeability reduction could divert the water into the rock matrix for increased sweep and recovery. The core plug in this work was an Edwards limestone core plug aged to oil-wet conditions, with a 1mm open fracture along the length of the core. The experimental procedures are detailed in **Appendix A.1.** The advantage of crosslinked polymers is that the molecule chains are too large to enter the porous rock matrix (Seright, 2001). Injection of polymer gel is thus an exclusive treatment of the fracture volume to reduce channeling. Prior to the experiment presented here, several gel extrusion experiments were performed to characterize the flow of gel in fractured chalk and limestone (Brattekås, 2009). These were compared to experiments by Seright (2001).

Figure 7 shows the obtained CT saturation profiles for gel placement and each of the waterfloods. The water preflush only recovered oil close to the inlet (X_D = 0-0.15) and 5% OIP was recovered after 0.34 PV injected. The polymer gel was then placed in the fracture to reduce fracture permeability. No recovery of oil was observed during gel placement. Chase water was injected at a rate identical to the preflush. The water advanced to X_D=0.65, increasing the sweep by ΔX_D=0.5, and increasing recovery by 15% OIP. The microscopic sweep was also increased, as oil was produced from areas already waterflooded during preflush. The chase water injection was terminated after 0.42 pore volumes injected water. At this point, water had broken through into the fracture and no more oil production was observed. The result show that polymer gel reduced the flow in fractures, thus diverting a chase fluid to increase sweep efficiency in a low permeable matrix.

Low injectivity of polymer gel is one limitation. It would thus be favorable to inject the solution as a gelant before it has crosslinked into polymer gel. Gelant is a polymer solution with an added cross-linking agent. It behaves like a Newtonian fluid, with low viscosity and relatively high injectivity. The cross-linking agent is activated by temperature, and after a given time known as the gelation time, the gelant is transformed into gel.

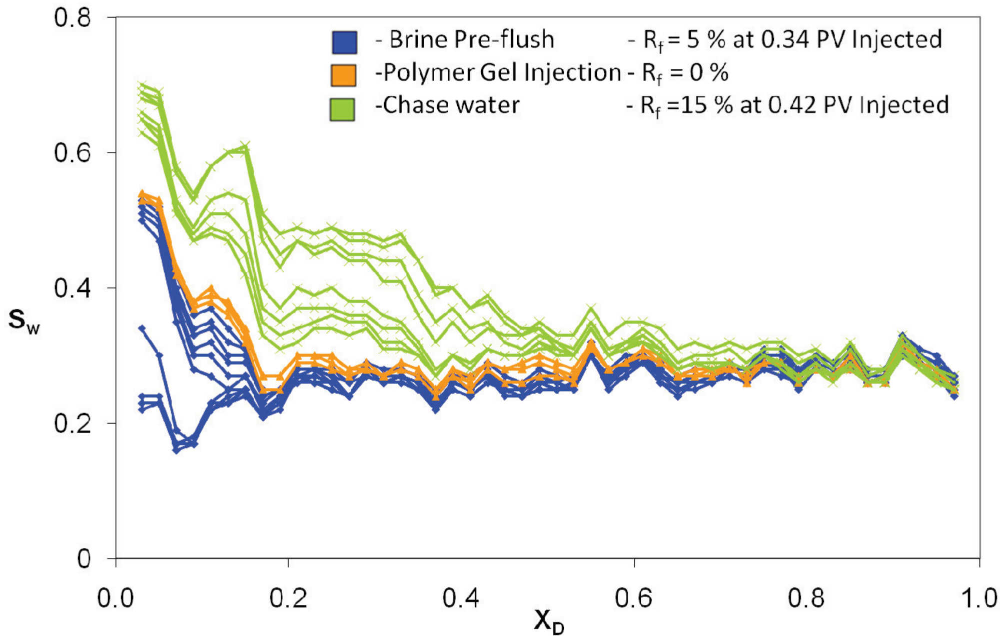

Figure 7: Saturation profiles during different stages of water or polymer gel injection. Recovery during preflush was 5% OIP, recovery during polymer gel injection was 0% and recovery during chase water injection was 15% OIP.

5.4.3 Foam versus Polymer Gel

The recovery by placing a polymer gel in the fracture and then injecting a chase fluid is much lower compared to the foam injection presented in **Paper 6**, with an added recovery of only 15% compared to almost 80% for foam. The systems were both of Edwards limestone at similar oil-wetting states. The fracture permeability was several orders of magnitude larger in the polymer gel case. From the cubic law (Miller, 2009), fracture permeability was in the order of $8x10^5$ D during gel placement, whereas the foam test had permeabilities in the order of 1 D. The advantage of the polymer gel was that the increased oil recovery was observed immediately after only fractions of the pore volume of chase fluid had been injected. The stability of the polymer gel is also greater than foam. The foam recovered significantly more oil, with a recovery of up to 80 % OIP. Between 40 and 200 pore volumes was needed to reach ultimate recovery, which at present is an unrealistically large amount relevant to any field case and more study on the impact form fracture permeability is needed.

6 Conclusions and Perspectives

This thesis used various imaging techniques to investigate the impact on oil recovery in fractured reservoirs at wettabilities ranging from strongly water-wet to moderately oil-wet conditions. *In-situ* fluid saturation development was obtained by NTI, CT and MRI during waterfloods and contributed to improved understanding of the recovery mechanisms during fluid flow in fractured blocks at different wettability conditions. It was determined that high permeable fractures severely reduce oil recovery and sweep efficiency if wettability tends toward less water-wet or oil-wet states. Based on this work, two methods for enhanced oil recovery were tested in fractured, oil-wet limestone, i.e. foam injection and polymer gel injection. The main contributions of this thesis were:

- The study of capillary continuity was extended to oil-wet conditions, and oil droplets were observed to establish capillary continuity across open fractures during oilfloods in oil-wet limestone. This corroborated the mechanistic similarity between waterfloods at moderately water-wet conditions and oilfloods at moderately oil-wet conditions. The work also identified a capillary threshold pressure for water to enter oil-wet rock matrix illustrating one of the challenges of EOR in fractured oil-wet rocks.
- Waterflood oil recovery was severely reduced at weakly water-wet and oil-wet conditions in the presence of high permeable fractures, and no transport of fluids from fracture to matrix was observed at oil-wet conditions
- *In-situ* saturation data was used to history match numerical simulations of laboratory waterfloods at various wettabilities. Numerical sensitivity studies identified fracture properties that influence fluid flow and oil recovery in fractured systems. The ratio of fracture to matrix permeability influenced ultimate waterflood oil recovery at oil-wet conditions. Reduction of fracture permeability was an important parameter to enhance oil recovery by improving viscous displacement at oil-wet conditions. Capillary continuity was numerically modeled by addressing capillary pressure in the fractures, and was found to impact both recovery and dynamics of fluid flow, especially in embedded fracture networks.
- Increased resistance to flow by injection of pre-generated foam in oil-wet, fractured limestone improved the oil recovery by up to 80% OIP from the matrix. This was superior to water, gas and surfactant injection that mainly recovered oil from the fracture network at comparable volumetric rates.
- *In-situ* generation of foam was not observed in fractures with smooth surfaces in oil-wet limestone. Consequently, gas mobility was not reduced in the fractures and enhanced recovery was not observed.
- Polymer gel was used to reduce fracture permeability and divert fluids away from the fracture to displace additional oil from the matrix. With polymer gel placed in the fracture, water was injected as a chase fluid and an increased oil recovery of 15% OIP from the matrix.

- Asymmetrical oil production and symmetrical waterfront invasion were observed during spontaneous brine imbibition into oil saturated core plugs at TEO boundary conditions. The asymmetry was independent of both rock type and initial water saturation. The asymmetrical production illustrates that small inhomogeneities may have a disproportionate effect on fluid displacement during spontaneous imbibition.

The work presented in **Paper 6** on foam is encouraging in terms of enhanced oil recovery, however, the system has several unresolved features. 1) The relationship between fracture/matrix permeability ratio to recovery rate should be investigated to find whether lower fracture permeabilities would reduce the need to inject vast amounts of foam. 2) A foaming surfactant with stronger stability in presence of oil should be tested to investigate whether this would provide more efficient flow. 3) Foam generation is very sensitive to the porous media. The roughness of natural fractures may need to be included to improve generation of foam in fractured media. 4) *In-situ* imaging of 3-phase systems during foam injection would also provide a better understanding of the dynamics of foam injection in fractured media, especially in terms of foam propagation. Experiments using CO_2-foam improved oil recovery at reservoir conditions (T=55°C, P= 34MPa) in weakly water-wet chalk (Zuta *et al.* (2009)), and extending to use of CO_2 is of interest.

Polymer gel for diversion of injected water is work in progress. One main concern with the gel is that it has a low injectivity and may be hard to extrude deep into a reservoir. Injection of gelant with *in-situ* forming of gel would be interesting to compare to pre-formed gel. Lubrication effects between fracture surface and polymer gel may be reduced if gelation take place in the fracture. This may provide more efficient plugging of the fracture. Work presented by Cordova *et al.* (2008) showed that gelation time can be increased, allowing a gelant to penetrate further into the reservoir before gelation. This may be important to extend use of gels deep into the reservoir.

Enhanced oil recovery may need to integrate several different techniques for combined benefits. Polymer gel and foam may be combined, where gel is used to plug the largest fractures or channels, whereas foam seems more favorable for diversion in more narrow fractures. The use of fluids that divert flow away from fractures may then contribute to displace additional oil from fractured reservoirs. The combined effects of foam and polymers or gels have been investigated by Sydansk (1994) and Miller and Fogler (1995) and provide higher mechanical stability to the foam and may improve the efficiency of mobility control. The contribution from capillary continuity by establishing liquid bridges has been shown to depend on wettability of the fracture surface, where waterflood at water-wet states other than strongly water-wet is favorable for liquid bridges. The use of surfactants (Xie *et al.,* 2005, Spinler *et al.,* 2000, Chen *et al.,* 2001), or ions in brine composition (Zhang and Austad, 2006, Strand *et al,.* 2006, Zhang *et al.,* 2007, Gupta and Mohanty, 2008, Karoussi and Hamouda, 2008) that can alter the fracture surface wettability from oil-wet to water-wet conditions may thus assist in establishing capillary continuity between matrix blocks. Using wettability alteration agents to treat the fracture surface only would reduce the amount of costly surfactants, compared to treating the whole reservoir.

The physics of capillary continuity by liquid bridges is not fully understood. It was modeled by straight line saturation dependent capillary pressure as seen in **Paper 1**.. Droplet growth starts at the pore scale, and the increasingly sophisticated pore scale models might provide insights to the phenomena controlling droplet growth that form into liquid bridges.

The TEO imbibition presented in this thesis was a fundamental study and only included a few data sets, and more data might better reveal the controlling mechanism of oil production from such systems. This should include the influence from oil/water viscosity ratio, initial water saturation, wettability and rock type.

Nomenclature

L_c = Characteristic Length
n = number of surfaces open to imbibition
μ_w = wetting phase viscosity
μ_{nw}= nonwetting phase viscosity
σ = Interfacial tension
φ = porosity
t = time
t_D = dimensionless time
I_{AH} = Amott-Harvey Index
P_c = Capillary Pressure
k_r = Relative Permeability
K = Absolute Permeability
IWS = Irreducible Water Saturation
IFT = Interfacial Tension
P = Pressure
T = Temperature
OIP = Oil In Place
PV = Pore Volume

Bibliography

[1] Al-Hadhrami, H. S. and M. J. Blunt."*Thermally Induced Wettability Alteration To Improve Oil Recovery in Fractured Reservoirs*." SPE Reservoir Eval. & Eng. : 179-186(2001).

[2] Aspenes, E., G. Ersland, A. Graue, J. Stevens and B. A. Baldwin."*Wetting Phase Bridges Establish Capillary Continuity Across Open Fractures and Increase Oil Recovery in Mixed-Wet Fractured Chalk*." Transport in Porous Media **Online First**(2007).

[3] Aspenes, E., A. Graue, B. A. Baldwin, A. Moradi, J. Stevens and D. P. Tobola. *Fluid Flow in Fractures Visualized by MRI During Waterfloods at Various Wettability Conditions - Emphasis on Fracture Width and Flow Rate*. SPE ATCE, San Antonio, TX, USA(2002).

[4] Austad, T. and J. Milter. *Spontaneous Imbibition of Water Into Low Permeable Chalk at Different Wettabilities Using Surfactants*. SPE International Symposium on Oilfield Chemistry Houston, Texas, USA(1997).

[5] Babadagli, T., A. Al-Bemani and F. Boukadi. Analysis of Capillary Imbibition Recovery Considering the Simultaneous Effects of Gravity, Low IFT, and Boundary Conditions. SPE Asia Pacific Improved Oil Recovery Conference. Kuala Lumpur, Malaysia, Society of Petroleum Engineers(1999).

[6] Babadagli, T. and I. Ershaghi. *Imbibition Assisted Two-Phase Flow in Natural Fractures*. SPE Western Regional Meeting Bakersfield, CA, USA(1992).

[7] Babadagli, T. and I. Ershaghi. Improved Modeling of Oil/Water Flow in Naturally Fractured Reservoirs Using Effective Fracture Relative Permeabilities. SPE Western Regional Meeting. Anchorage, Alaska, 1993(1993).

[8] Barenblatt, G. I., Y. P. Zheltov and I. N. Kochina."*Basic Consepts in the Theory of Seepage of Homogeneous Liquids in Fissured Rocks*." Journal of Applied Math. **24**(4): 1286-1303(1960).

[9] Bergeron, V., M. E. Fagan and C. J. Radke."*Generalized entering coefficients: a criterion for foam stability against oil in porous media*." Langmuir **9**(7): 1704-1713(1993).

[10] Bernard, G. B. and W. L. Jacobs."*Effect of Foam on Trapped Gas Saturation and on Permeability of Porous Media to Water*." SPEJ **4**(1965).

[11] Bernard, G. G. and L. W. Holm."*Effect of Foam on Permeability of Porous Media to Gas*." **4**(3): 267 - 274(1964).

[12] Bertin, H. J., O. G. Apaydin, L. M. Castanier and A. R. Kovscek."*Foam Flow in Heterogeneous Porous Media: Effect of Crossflow*." SPEJ **4**(2): 75-82(1999).

[13] Bourbiaux, B. J.: Understanding the Oil Recovery Challenge of Water Drive Fractured Reservoirs. International Petroleum Technology Conference. Doha, Qatar, 2009, International Petroleum Technology Conference(2009).

[14] Bourbiaux, B. J. and F. J. Kalaydjian."*Experimental study of cocurrent and countercurrent flows in natural porous media*." SPE Reservoir Eval. & Eng. **5**: 361–368(1990).

[15] Brattekås, B.: EOR by Polymer Gel Extrusion through Fractures: An Experimental Study of Water Leakoff as Function of Flow Rate, Wettability and Relative Permeability. Dept. of Physics and Technology. Bergen, University of Bergen. **Master thesis**(2009).

[16] Cardwell, W. T. and R. L. Parsons."*Gravity Drainage Theory*." Trans Aime(1949).

[17] Casteel, J. F. and N. F. Djabbarah."*Sweep Improvement in CO2 Flooding by Use of Foaming Agents*." SPE Reservoir Engineering **3**(4): 1186-1192(1988).

[18] Chen, H. L., L. R. Lucas, L. A. D. Nogaret, H. D. Yang and D. E. Kenyon."*Laboratory Monitoring of Surfactant Imbibition With Computerized Tomography*." SPE Reservoir Evaluation & Engineering **4**(1): 16-25(2001).
[19] Cordova, M., M. Cheng, J. Trejo, S. J. Johnson, G. P. Willhite, J.-T. Liang and C. Berkland."*Delayed HPAM Gelation via Transient Sequestration of Chromium in Polyelectrolyte Complex Nanoparticles*." Macromolecules **41**(12): 4398-4404(2008).
[20] de la Porte, J. J., C. A. Kossack and R. W. Zimmerman. *The effect of fracture relative permeability and capillary pressures on the numerical simulation of naturally fractured reservoirs*. SPE ATCE, Dallas, TX, USA(2005).
[21] Eclipse100. Eclipes 100 Simulation Software Manuals 2007.1(2007).
[22] Ersland, G., M. A. Fernø, A. Graue, B. A. Baldwin and J. Stevens."*Complementary Imaging of Oil Recovery Mechanisms in Fractured Reservoirs*." Chemical Engineering Journal(2008).
[23] Firoozabadi, A.:"*Recovery Mechanisms in Fractured Reservoirs and Field Performance*." J. Can. Pet. Tech. **39**(11): 13-17(2000).
[24] Firoozabadi, A. and J. Hauge."*Capillary Pressure in Fractured Porous Media*." Journal of Petroleum Technology **42**(6): 784-791(1990).
[25] Firoozabadi, A. and T. Markeset."*Fracture-Liquid Transmissibility in Fractured Porous Media*." SPE Reservoir Eng. **9**(3): 201-207(1994).
[26] Fjelde, I., J. Zuta and O. V. Duyilemi. Oil Recovery from Matrix during CO2-Foam Flooding of Fractured Carbonate Oil Reservoirs. Europec/EAGE Conference and Exhibition. Rome, Italy, Society of Petroleum Engineers(2008).
[27] Fourar, M., S. Bories, R. Lenormand and P. Persoff."*Two-Phase Flow in Smooth and Rough Fractures: Measurement and Correlation by Porous-Medium and Pipe Flow Models*." Water Resour. Res. **22**(9)(1993).
[28] Gautam, P. S. and K. K. Mohanty."*Matrix–Fracture Transfer through Countercurrent Imbibition in Presence of Fracture Fluid Flow*." Transport in Porous Media **55**(3): 309-337(2004).
[29] Graue, A., E. Aspenes, R. W. Moe, B. A. Baldwin, A. Moradi, J. Stevens and D. Tobola. *MRI Tomography of Saturation Development in Fractures During Waterfloods at Various Wettability Conditions*. SPE ATCE, New Orleans, LA, USA(2001a).
[30] Graue, A., B. A. Baldwin, E. Aspenes, J. Stevens, D. P. Tobola and D. R. Zornes. *Complementary imaging techniques applying NTI and MRI determined wettability effects on oil recovery mechanisms in fractured reservoirs* International Symposium of the Society of Core Analysts, Pau, France(2000a).
[31] Graue, A., T. Bognø, B. A. Baldwin and E. A. Spinler."*Wettability Effects on Oil Recovery Mechanisms in Fractured Reservoirs*." SPE Reservoir Eval. & Eng. **4**(6): 455-466(2001b).
[32] Graue, A., R. W. Moe and B. A. Baldwin. *Comparison of Numerical Simulations and Laboratory Waterfloods with In-Situ Saturation Imaging of Fractured Blocks of Reservoir Rocks at Different Wettabilities*. SPE International Petroleum Conference and Exhibition in Mexico, Villahermosa, Mexico(2000b).
[33] Graue, A., K. Nesse, B. A. Baldwin, E. A. Spinler and D. Tobola. *Impact of Fracture Permeability on Oil Recovery in Moderately Water-Wet Fractured Chalk Reservoirs*. SPE/DOE Improved Oil Recovery Symposium, Tulsa, OK, USA(2002).
[34] Graue, A., B. G. Viksund and B. A. Baldwin."*Reproducible Wettability Alteration of Low-Permeable Outcrop Chalk*." SPE Reservoir Evaluation & Engineering **2**(2): 134-140(1999).

[35] Gupta, R. and K. K. Mohanty. Temperature Effects on Surfactant-Aided Imbibition Into Fractured Carbonates. SPE Annual Technical Conference and Exhibition. Anaheim, California, U.S.A., Society of Petroleum Engineers(2007).
[36] Gupta, R. and K. K. Mohanty. Wettability Alteration of Fractured Carbonate Reservoirs. SPE/DOE Symposium on Improved Oil Recovery. Tulsa, Oklahoma, USA, Society of Petroleum Engineers(2008).
[37] Hagoort, J.:"*Oil Recovery by Gravity Drainage*." SPE J.: 139-150(1980).
[38] Han, C., J. M. Kang and J. Choe. Monte Carlo Simulation on the Effect of Fracture Characteristics on Reduction of Permeability by In-Situ Bacteria Growth. SPE Asia Pacific Improved Oil Recovery Conference. Kuala Lumpur, Malaysia, Society of Petroleum Engineers(2001).
[39] Hermansen, H., G. H. Landa, J. E. Sylte and L. K. Thomas."*Experiences after 10 years of waterflooding the Ekofisk Field, Norway*." Journal of Petroleum Science and Engineering **26**: 11-18(2000).
[40] Hirasaki, G. J.:"*The Steam-Foam Process--Review of Steam-Foam Process Mechanisms (Supplement to SPE 19505)*." (1989).
[41] Holm, L. W.:"*The Mechanism of Gas and Liquid Flow Through Porous Media in the Presence of Foam*." **8**(4): 359 - 369(1968).
[42] Horie, T. and A. Firoozabadi. *Capillary Continuity in Fractured Reservoirs*. APE Annual Technical Meeting, Houston, TX, USA(1988).
[43] Horie, T., A. Firoozabadi and K. Ishimoto."*Laboratory Studies of Capillary Interaction in Fracture/Matrix Systems*." SPE Reservoir Eng. **5**(3): 353-360(1990).
[44] Jensen, J. A. and F. Friedmann. Physical and Chemical Effects of an Oil Phase on the Propagation of Foam in Porous Media. SPE California Regional Meeting. Ventura, California, 1987 Copyright 1987, Society of Petroleum Engineers Inc.(1987).
[45] Jones, T. A., S. O. Wooten and T. J. Kaluza. Single-Phase Flow Through Natural Fractures. SPE Annual Technical Conference and Exhibition. Houston, Texas, 1988 Copyright 1988 Society of Petroleum Engineers(1988).
[46] Karimaie, H. and O. Torseter."*Effect of injection rate, initial water saturation and gravity on water injection in slightly water-wet fractured porous media*." Journal of Petroleum Science and Engineering **58**: 293-308(2007).
[47] Karimaie, H. and O. Torsæter."*Low IFT gas-oil gravity drainage in fractured carbonate porous media*." Journal of Petroleum Science and Engineering **70**(1-2): 67-73(2010).
[48] Karimaie, H., O. Torsæter, M. R. Esfahani, M. Dadashpour and S. M. Hashemi."*Experimental investigation of oil recovery during water imbibition*." Journal of Petroleum Science and Engineering **52**(1-4): 297-304(2006).
[49] Karoussi, O. and A. A. Hamouda."*Imbibition of Sulfate and Magnesium Ions into Carbonate Rocks at Elevated Temperatures and Their Influence on Wettability Alteration and Oil Recovery*." Energy & Fuels **22**(3): 2129-2130(2008).
[50] Karpyn, Z. T., P. M. Halleck and A. S. Grader."*An experimental study of spontaneous imbibition in fractured sandstone with contrasting sedimentary layers*." Journal of Petroleum Science and Engineering **67**: 48-65(2009).
[51] Kazemi, H., J. S. Merril Jr., K. L. Poterfield and P. R. Zeman."*Numerical simulation of water-oil flow in naturally fractured reservoirs*." SPE J. **16**: 317-326(1976).
[52] Kovscek, A. R., D. C. Tretheway, P. Persoff and C. J. Radke."*Foam flow through a transparent rough-walled fracture*." Journal of Petroleum Science and Engineering **17**: 75-86(1995).

[53] Labastie, A.: *Capillary Continuity Between Blocks of a Fractured Reservoir*. SPE ATCE, New Orleans, LA, USA(1990).
[54] Li, K. and R. N. Horne."*Generalized Scaling Approach for Spontaneous Imbibition: An Analytical Model*." SPE Reservoir Evaluation & Engineering **9**(3): pp. 251-258(2006).
[55] Li, Y., D. Ruth, G. Mason and N. R. Morrow."*Pressures acting in counter-current spontaneous imbibition*." Journal of Petroleum Science and Engineering **52**(1-4): 87-99(2006).
[56] Llave, F. M., F. T.-H. Chung, R. W. Louvier and D. A. Hudgins. Foams as Mobility Control Agents for Oil Recovery by Gas Displacement. SPE/DOE Enhanced Oil Recovery Symposium. Tulsa, Oklahoma, 1990 Copyright 1990, Society of Petroleum Engineers, Inc.(1990).
[57] Lomize, G. M.:" *Flow in Fractured Rocks*." Gosenergoizdat, Moscow(1951).
[58] Ma, S., N. R. Morrow and X. Zhang."*Generalized scaling of spontaneous imbibition data for strongly water-wet systems*." Journal of Petroleum Science and Engineering **18**(3-4): 165-178(1997).
[59] Mattax, C. C. and J. R. Kyte."*Imbibition Oil Recovery from Fractured, Water-Drive Reservoir*." SPE J. **2**(2): 177-184(1962).
[60] Matthäi, S. K.: Simulation of Multiphase Flow in Naturally Fractured Reservoirs. Course Handouts(2009).
[61] Miller, M.: Naturally Fractured Reservoir Engineering. Reservoir Engineering Course Handouts. Vienna, Austria, HOT Engineering. **Course handouts**(2009).
[62] Miller, M. J. and H. S. Fogler."*A Mechanistic Investigation of Waterflood Diversion Using Foamed Gels*." SPE Production & Operations **10**(1): 62-70(1995).
[63] Morrow, N. R. and G. Mason."*Recovery of oil by spontaneous imbibition*." Current Opinion in Colloid & Interface Science **6**(4): 321-337(2001).
[64] Nelson, R.: Geologic Analysis of Naturally Fractured Reservoirs. Boston, Gulf Professional Publ.(2001).
[65] Pan, X.: Immiscible two-phase flow in a fracture. Calgary, Alberta, Canada, University of Calagry. **PhD**(2000).
[66] Persoff, P., K. Pruess and L. Myer. *Two-Phase Flow Visualization and Relative Permeability Measurement in Transparent Replicas of Rough-Walled Rock Fractures*. Sixteenth Stanford Geothermal Workshop, Stanford University, Stanford University, Stanford, CA(1991).
[67] Pooladi-Darvish, M. and A. Firoozabadi."*Cocurrent and Countercurrent Imbibition in a Water-Wet Matrix Block*." SPEJ **5**(1): 3-11(2000).
[68] Pratap, M., J. Kleppe and K. Uleberg. Vertical Capillary Continuity Between the Matrix Blocks in a Fractured Reservoir Dramatically Improves the Oil Recovery by Water Displacement. Middle East Oil Show and Conference. Bahrain, Copyright 1997,Society of Petroleum Engineers, Inc.(1997).
[69] Rangel-German, E. R., S. Akin and L. Castanier."*Multiphase-flow properties of fractured porous media*." Journal of Petroleum Science and Engineering **51**(3-4): 197-213(2006).
[70] Rangel-German, E. R. and A. R. Kovscek."*Experimental and analytical study of multidimensional imbibition in fractured porous media*." Journal of Petroleum Science and Engineering **36**(1-2): 45-60(2002).
[71] Rangel-German, E. R. and A. R. Kovscek."*A micromodel investigation of two-phase matrix-fracture transfer mechanisms*." Water Resour. Res **42**(2006).

[72] Ransohoff, T. C. and C. J. Radke."*Mechanisms of Foam Generation in Glass-Bead Packs*." SPE Reservoir Engineering **3**(2): 573-585(1988).
[73] Romm, E. S.: Fluid Flow in Fractures. Moscow, Nedra Publishing House(1966).
[74] Rossen, W. R.: Foams in Enhanced Oil Recovery. FOAMS - Theory, Measurements, and Applications. R. K. Prud'homm and S. A. Khan. New York, Marcel Dekekr(1995).
[75] Rossen, W. R. and A. T. A. Kumar. Single- and Two-Phase Flow in Natural Fractures. SPE Annual Technical Conference and Exhibition. Washington, D.C., 1992 Copyright 1992, Society of Petroleum Engineers Inc.(1992).
[76] Rossen, W. R. and A. T. A. Kumar. Effect of Fracture Relative Permeabilities on Performance of Naturally Fractured Reservoirs. International Petroleum Conference and Exhibition of Mexico. Veracruz, Mexico, Society of Petroleum Engineers(1994).
[77] Saidi, A. M.: *Mathematical Simulation Model Describing Iranian Fractured Reservoirs and it's Application to Haft Kel Field*. Ninth World Petroleum Congress, Japan(1975).
[78] Saidi, A. M.: Reservoir engineering of fractured reservoirs. Paris, Total edition presse(1987).
[79] Saidi, A. M., D. H. Tehrani and K. Wit. PD 10(3) Mathematical Simulation of Fractured Reservoir Performance, Based on Physical Model Experiments. 10th World Petroleum Congress. Bucharest, Romania, World Petroleum Congres(1979).
[80] Sanchez, J. M. and R. D. Hazlett."*Foam Flow Through an Oil-Wet Porous Medium: A Laboratory Study*." SPE Reservoir Engineering **7**(1): 91-97(1992).
[81] Schembre, J. M., G. Q. Tang and A. R. Kovscek."*Wettability alteration and oil recovery by water imbibition at elevated temperatures*." Journal of Petroleum Science and Engineering **52**(1-4): 131-148(2006).
[82] Schramm, L. L. and K. Mannhardt."*The effect of wettability on foam sensitivity to crude oil in porous media*." Journal of Petroleum Science and Engineering **15**(1): 101-113(1996).
[83] Sendra. Sendra Core Simulator v1.9 User Manual(2007).
[84] Seright, R. S.:"*Use of Preformed Gels for Conformance Control in Fractured Systems*." SPE Production & Operations **12**(1): 59-65(1997).
[85] Seright, R. S.:"*Polymer Gel Dehydration During Extrusion Through Fractures*." SPE Production & Facilities **14**(2): 110-116(1999).
[86] Seright, R. S.:"*Gel Propagation Through Fractures* " SPE Production & Facilities **16**(4): 225-231(2001).
[87] Seright, R. S., R. H. Lane and R. D. Sydansk. A Strategy for Attacking Excess Water Production. SPE Permian Basin Oil and Gas Recovery Conference. Midland, Texas, Copyright 2001, Society of Petroleum Engineers Inc.(2001).
[88] Seright, R. S. and R. L. Lee."*Gel Treatments for Reducing Channeling in Naturally Fractured Reservoirs*." SPE Production & Operations **14**(4): 269-276(1999).
[89] Shad, S. and I. D. Gates."*Multiphase Flow in Fractures: Co-Current and Counter-Current Flow in a Fracture*." **49**(2): 48-55(2010).
[90] Spinler, E. A., D. R. Zornes, D. P. Tobola and A. Moradi-Araghi. Enhancement of Oil Recovery Using a Low Concentration of Surfactant to Improve Spontaneous and Forced Imbibition in Chalk. SPE/DOE Improved Oil Recovery Symposium. Tulsa, Oklahoma, Copyright 2000, Society of Petroleum Engineers Inc.(2000).

[91] Standnes, D. C., L. A. D. Nogaret, C. H.L. and A. T."*An Evaluation of Spontaneous Imbibition of Water into Oil-Wet Carbonate Reservoir Cores Using a Nonionic and a Cationic Surfactant*." Energy and Fuels **16**: 1557-1564(2002).
[92] Stones, E. J., S. A. Zimmerman, C. V. Chien and S. S. Marsden. *The Effect of Capillary Connectivity Across Horizontal Fractures on Gravity Drainage From Fractured Porous Media*. SPE ATCE, Washington, D.C., USA(1992).
[93] Strand, S., E. J. Høgnesen and T. Austad."*Wettability alteration of carbonates--Effects of potential determining ions (Ca2+ and SO42-) and temperature*." Colloids and Surfaces A: Physicochemical and Engineering Aspects **275**(1-3): 1-10(2006).
[94] Sydansk, R. D.:"*Polymer-Enhanced Foams Part 1: Laboratory Development and Evaluation*." SPE Advanced Technology Series **2**(2): 150-159(1994).
[95] Sydansk, R. D. and P. E. Moore."*Gel Conformance Treatments Increase Oil Production in Wyoming*." Oil & Gas J. **40**(1992).
[96] Sydansk, R. D. and G. P. Southwell."*More Than 12 Years' Experience With a Successful Conformance-Control Polymer-Gel Technology*." SPE Production & Facilities **15**(4): 270-278(2000).
[97] Tang, G. and A. Firoozabadi."*Effect of Pressure Gradient and Initial Water Saturation on Water Injection in Water-Wet and Mixed-Wet Fractured Porous Media*." SPE Reserv. Evalu. Eng.: 516-524(2001).
[98] Tang, G. Q. and N. R. Morrow."*Salinity, Temperature, Oil Composition, and Oil Recovery by Waterflooding*." SPE Reservoir Engineering **12**(4): 269-276(1997).
[99] Torsaeter, O. and J. K. Silseth. *The Effects of Sample shape and boundary Conditions on Capillary Imbibition*. Symp. on North Sea Chalk, Stavanger, Norway(1985).
[100] Unsal, E., G. Mason, N. R. Morrow and D. Ruth."*Co-current and counter current imbibition in independent tubes of non-axisymmetric geometry*." Journal of Colloid and Interface Science **306**: 105-117(2006).
[101] van Golf-Racht, T. D.: Fundamentals of fractured reservoir engineering. New York, Elsevier(1982).
[102] Viksund, B. G., N. R. Morrow, S. Ma and A. Graue. *INITIAL WATER SATURATION AND OIL RECOVERY FROM CHALK AND SANDSTONE BY SPONTANEOUS IMBIBITION*. Inlt. Symposium of Soc. of Core Analysts, The Hague(1998).
[103] Willhite, G. P. and R. E. Pancake."*Controlling Water Production Using Gelled Polymer Systems*." SPE Reservoir Evaluation & Engineering **11**(3): 454-465(2008).
[104] Witherspoon, P. A., J. S. Y. Wang, K. Iwai and J. E. Gale."*Validity of Cubic Law for Fluid Flow in a Deformable Rock Fracture*." Water Resour. Res. **16**(6): 1016-1024(1980).
[105] Wu, Y.-S., L. Pan and K. Pruess."*A physically based approach for modeling multiphase fracture-matrix interaction in fractured porous media*." Advances in Water Resources **27**(9): 875-887(2004).
[106] Xie, X., W. W. Weiss, Z. J. Tong and N. R. Morrow."*Improved Oil Recovery from Carbonate Reservoirs by Chemical Stimulation*." SPE Journal **10**(3): pp. 276-285(2005).
[107] Yan, W., C. A. Miller and G. J. Hirasaki."*Foam sweep in fractures for enhanced oil recovery*." Colloids and Surfaces A: Physicochemical and Engineering Aspects **282-283**: 348-359(2006).
[108] Zekri, A. Y. and R. A. El-Mehaideb. Microbial and Waterflooding of Fractured Carbonate Rocks: An Experimental Approach. SPE/DOE Improved Oil Recovery Symposium. Tulsa, Oklahoma, Copyright 2002, Society of Petroleum Engineers Inc.(2002).

[109] Zerhboub, M., E. Touboul, K. Ben-Naceur and R. L. Thomas."*Matrix Acidizing: A Novel Approach to Foam Diversion* " SPE Production & Facilities **9**(2): 121-126(1994).
[110] Zhang, P. and T. Austad."*Wettability and oil recovery from carbonates: Effects of temperature and potential determining ions*." Colloids and Surfaces A: Physicochemical and Engineering Aspects **279**(1-3): 179-187(2006).
[111] Zhang, P., M. T. Tweheyo and T. Austad."*Wettability alteration and improved oil recovery by spontaneous imbibition of seawater into chalk: Impact of the potential determining ions Ca2+, Mg2+, and SO42*." Colloids and Surfaces A: Physicochemical and Engineering Aspects **301**(1-3): 199-208(2007).
[112] Zhang, X., N. R. Morrow and S. Ma."*Experimental verification of a modified scaling group for spontaneous imbibition*." SPE Reservoir Eng. **11**(4): 280-285(1996).
[113] Zhou, X., N. R. Morrow and S. Ma."*Interrelationship of Wettability, Initial Water Saturation, Aging Time, and Oil Recovery by Spontaneous Imbibition and Waterflooding*." SPE J. **5**(2): 199-207(2000).
[114] Zuta, J. and I. Fjelde. *Transport of CO2-Foaming Agents During CO"-Foam Processes in Fractured Chalk Rock*. SPE EUROPEC/EAGE, Asmterdam, NL, SPE(2009).
[115] Zuta, J., I. Fjelde and R. Berenblyum. *Oil Recovery During CO2-Foam Injection in Fractured Chalk Rock at Reservoirs Conditions*. Intl. Symposium of SCA, Noordwijk, NL(2009).

Appendix A

A.1 Experimental Procedures for Polymer Gel Placement

A.1.1 Core Preparation

Edwards limestone was used to study gel placement in a fractured core. The core was saturated with 0.1M NaCl brine solution under vacuum and porosity was calculated by weight measurements. The porous rock was characterized in terms of porosity and permeability variations within the core during a miscible brine-brine displacement in a CT flow rig.

A.1.2 Wettability Alteration

The wettability of the originally strongly water-wet outcrop limestone core was altered to moderately oil-wet by exposing the rock to crude oil during dynamic aging. Dynamic aging (Graue *et al.*, 2002 and Aspenes *et al.*, 2003) creates a uniformly distributed and stable wettability preference in the core by flushing crude oil through the core at elevated temperature. The core was placed in a biaxial core holder with a net confining pressure of 15 bars, and drained by injecting crude oil at a constant differential pressure of 2bars/cm; which corresponds to about 20 bars inlet pressure on the 101mm long core plug. To minimize capillary end effects during drainage, the direction of the crude oil injection was reversed when no further water production was observed. After drainage was completed, the injection was switched to constant injection rate mode with a 1.5 ml/h flow rate and maintained for 10 days. This allowed the core to be contacted by fresh crude oil continuously during aging. Direction of injection was reversed after 5 days. Crude oil was filtered through a chalk core to remove impurities and large particles that obstruct the pore throats and reduce permeability of the core. The aging process was terminated by miscibly displacing the crude oil from the core with 5 PV of decahydronaphthalene (decaline) followed by 5 PV of decane. Decaline was used as a buffer between the crude oil and the decane to avoid precipitation of asphaltenes and resins in the crude oil if contacted directly by decane. The simplified oil chemistry by using decane provided stable wettability conditions and has previously shown to give reproducible results. All miscible displacements were performed at 80°C.

The wetting preference was not explicitly measured, but was measured on sister plugs aged with the same crude oil. All cores displayed negative A-H indices between -0.2 and -0.7, depending on the aging time. Therefore, it was very likely that the core used in the CT experiment also exhibited negative A-H values. Hence, no water will spontaneously enter the matrix from the fracture during water injection.

A.1.3 Fractured Core Assembly

The core was cut along its length and the 1mm aperture held open by two POM spacers constituted the fracture, see top **Figure A1**. Specially designed end pieces were made to inject the gel directly into the fracture and the water directly into the matrix. The end piece was designed to isolate the upper and lower core halves from the fracture. Fluid communication between the three injectors was prevented by smearing silicone on the end piece. Correct positioning of the end piece relative to the fluid injection points was verified by CT -images, see Bottom **Figure A1**.

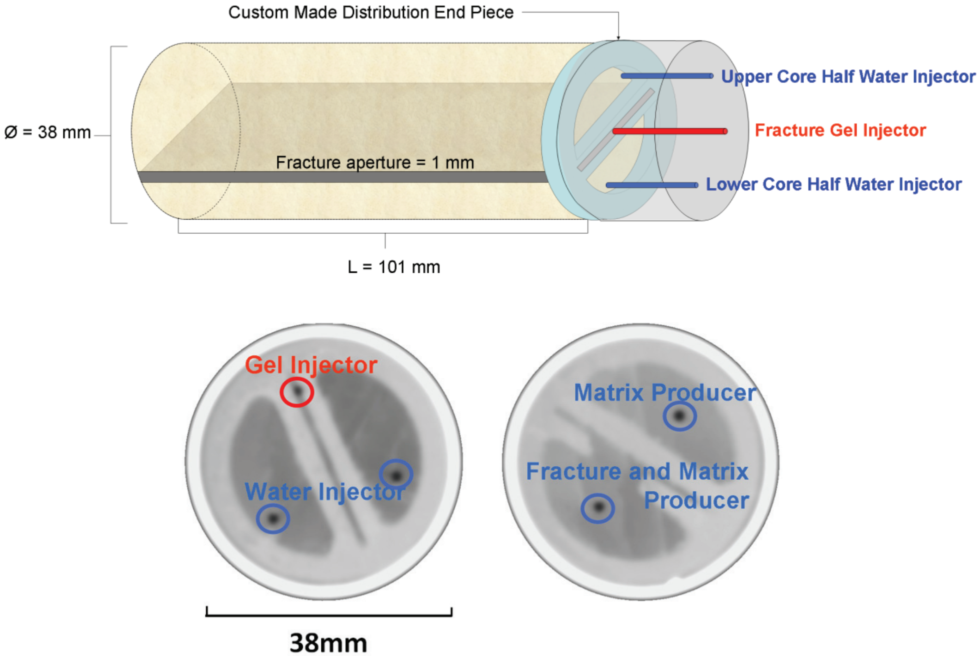

Figure A1. *Top*: Schematics of experimental design of core with longitudinal fracture of 1mm aperture. The specially designed inlet end piece ensured that injected fluids in each part (upper core half, fracture and lower core half) of the fractured core were separated from each other at the inlet face. *Bottom*: A silicone coat in the grooves on the inlet end piece restricted fluid distribution and communication on the end piece, and stabilized the spacer system during assembly. Two CT-images verified the position of injector and producers and placement of the distribution end piece.

A.1.4 Polymer Gel

The Polymer gel used in this test was Cr(III)-Acetate-HPAM gel identical to gel used by Seright (1999). A polymer solution containing 0.5% Alcoflood 935 HPAM in 4wt% NaI brine was mixed in a beaker with a stir bar until clump free. The solution was stirred at a high speed until the polymer was partly dissolved in the brine, then left at reduced speed until fully dissolved. Chrome-acetate (0.0417wt%) for cross-linking was then added and aged for 24hours at 41°C to form polymer gel.

A.1.5 Calculation of Spatial Water Saturation

The CT scanner (Picker PQ-6000) offers high 3D resolution imaging at millimeter scale. The operating parameters of the CT are 100 mA, 130 kV. The voxel size is 0.12x0.12x2 mm in the xyz direction, where the xy-plane is parallel to the cross-sectional area of the core plug and the z-axis is along the core length. High accuracy in core positioning is required since only subtle differences in the x-ray signal is used to calculate fluid saturations at a given position. This is an invariable requirement when imaging heterogeneous rocks. To obtain quantitative 3D images at full resolution the core should not be removed from the scanner rig during a test. To accuractely generate 3D saturation images, intensity scans at 100% water saturation and 100% oil satuation must be obtained. Due to time constrains and the location of laboratory, the core was removed from the CT after the miscible flood, shipped to another lab and replaced in the CT rig after aging and fracturing. Scans at 100% oil saturation was not obtained since this relied on the slow process of diffusion to remove all the oil or all the water due to the highly fractured nature of the core. Thus, the 3D high resolution images were qualitative only, restricted to studying differences in signal intensties rather than fluid saturations. Reducton of high spatial 3D images to 1D by averaging produced reliable and quantitative 1D satuation profiles that could be used to quantify the saturation changes in the matrix during the water and gel injections.

A.1.6 Experimental Schedule

The experimental schedule was divided into three stages: preflush, gel placement and chase water as listed below. CT images were obtained continuously during injection.

1. **Preflush**: Initially both core halves were at S_{wi} and the fracture was filled with decane. Water was injected separately in each core half using two injection pumps with constant injection rates of 1.5ml/h in each half, with a total injection rate of 3ml/h. Water was injected directly into the matrix and oil recovery was continuously monitored every 15 min using the CT scanner. Water injection was terminated when no more oil recovery was observed over several CT images.
2. **Gel placement**: Gel was injected with a constant rate (6ml/h) into the fracture after the preflush was terminated. Gel was injected in the fracture only, while monitoring pressure and the development in fluid saturation using the CT scanner. Gel injection was stopped after 40 fracture volumes injected and a 3D saturation image was obtained at the end to observe that the entire fracture was filled with gel, and to identify any additional oil recovery as a result of gel placement.
3. **Chase water**: Chase water was injected directly into the two matrix halves after the first gel placement. During chase water injection the additional oil recovery and increased water sweep as a result of reduced flow capacity in the fracture was monitored by the CT scanner. Injection rate was equal to that of the preflush; 1.5ml/h for each core half. Injection was terminated when no additional saturation change was detected by the CT images.

A.2 Additional Papers Published or Accepted during PhD

1. Fernø, M.A., Ersland, G., **Haugen, Å.**, Johannesen, E., Graue, A., Stevens, J., and Howard, J.J.: "Impacts From Fractures On Oil Recovery Mechanisms In Carbonate Rocks At Oil-Wet And Water-Wet Conditions - Visualizing Fluid Flow Across Fractures With MRI", SPE 108699, International Oil Conference and Exhibition, Veracruz, Mexico, June 27-30, 2007.

2. Fernø, M.A., **Haugen, Å.**, Howard, J.J. and Graue, A. "*The significance of wettability and fracture properties on oil recovery efficiency in fractured carbonates*", reviewed proceedings at the International Symposium of the Society of Core Analysts, Abu Dhabi, UAE, October 29 - November 2, 2008.

3. Fernø, M.A., **Haugen, Å.**, Graue, A. *"Visualizing Oil Displacement in Fractured Carbonate Rocks – Impacts on Oil Recovery at Different Hydrostatic Stress and Wettability Conditions"*, reviewed and accepted proceedings for presentation at the 44th US Rock Mechanics Symposium and 5th U.S.-Canada Rock Mechanics Symposium, Salt Lake City, UT June 27–30, 2010.

Scientific Papers