A Study of Capillary Pressure and Capillary Continuity in Fractured Rocks

By

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Table of content

Summary

The production of oil is challenging in fractured reservoirs due to the large transmissibility contrast between matrix and fracture, and primary recovery is often low. The recovery efficiency depends on the relationship between the fracture and matrix permeabilities, and is strongly dependent on the wettability of the matrix, which reflects the imbibition potential of the reservoir. High demands and rising oil prices has increased focus on improved oil recovery from large, low recovery oil fields. Some of the world's largest remaining oil reserves are found in oil-wet, fractured, carbonate reservoirs. The understanding of multiphase fluid flow in oil-wet fractured reservoirs has been studied in this thesis, especially the influence of capillary pressure. The presence of capillary pressure is important in recovery mechanisms like spontaneous imbibition, waterflooding and gravity drainage.

The centrifuge method is a frequently used method to measure capillary pressure, and relies on establishing a stable saturation for each rotational speed. There exists no global, absolute requirement for equilibrium, and this size is often based on experience, and is strongly dependent on the sensitivity of the measuring apparatus. The benefits of using an automated, high resolution camera in volume measurements have been demonstrated, and the impact of accuracy on the time to reach equilibrium saturation at a given rotational speed is illustrated.

Another difficulty when generating the capillary pressure curve using a centrifuge is the large uncertainty related to solving the integral problem associated with the calculation of the capillary pressure curve from production data. Methodologies for direct measurement of saturation to avoid this uncertainty have been proposed, eliminating the need for mathematical approximate solutions to obtain the local capillary pressure curve. The Nuclear Tracer Imaging Centrifuge (NTIC) method has the capability to measure the local water saturation during centrifugation, thus limiting the redistribution of fluids and the need to solidify phases, drawbacks associated with other methods for direct measurement of capillary pressure. Improved capillary pressure curves are presented, and the reliability and reproducibility in the NTIC capillary pressure curves have been demonstrated. The curves generally coincided with results from other existing centrifuge methods. The correct measurement of saturation as a function of capillary pressure will increase the confidence in simulations where the input multiphase controls the flow patterns and the recovery.

The impact of wettability on capillary continuity in fractured rocks has been studied extensively, but is still not fully understood. Two visualization methods, to measure the *in situ* fluid saturation development in fractured rocks, are reviewed and illustrate the benefits of applying complimentary imaging to study the impact of fractures and wettability on multiphase flow in fractured reservoirs. Separately, each technique provided useful insights to local phenomena, but collectively, when combining the resolutions and observations made, a better explanation of observed phenomena could be obtained.

The concept of wetting phase bridges observed during waterfloods in stacked water-wet homogenous chalk plugs has been extended to a heterogeneous limestone rock type with an oil-wet wetting preference. The study shows how droplets of oil forming on the fracture surface contribute to the fluid transfer between two separated matrix blocks across an open fracture. The presence of droplets, evolving into bridges across the fracture, may be important for gravity drainage, reducing the capillary retained oil in each isolated matrix block. Droplets growth is impacted by the wettability of the interface between fracture and matrix and flow rates. Spontaneous transport of oil, i.e. transport without associated pressure increase, across the fracture was observed when there was an affinity between mobile fluid and the wettability of the fracture surface. Injection rates and pressure across the fracture controlled droplet growth and the potential for the droplets to bridge the fracture to form a continuum in the capillary pressure curve.

The importance of fracture capillary pressure in waterfloods of fractured limestone rocks was demonstrated in a numerical reproduction of experimental results. The results showed not only that there was a dependency of the presence of capillary pressure in the fracture, but also there was a strong dependency of the distribution of the capillary pressure inside the fracture network on the development of waterfronts during water injection.

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List of papers

1. **Fernø, M.A.**, Ersland, G., Haugen, Å., Graue, A., Stevens, J. and Howard, J.J. "*Experimental measurements of capillary pressure with the centrifuge technique – emphasis on equilibrium time and accuracy in production*", reviewed proceedings at the International Symposium of the Society of Core Analysts, Calgary, Canada, September 10-13, 2007

2. **Fernø, M.A.**, Bull, Ø., Sukka, P.O. and Graue, A. "*Capillary pressures obtained by dynamic in situ fluid saturation measurements during core plug centrifugation*", 2008, submitted to Transport in Porous Media

3. Ersland, G., **Fernø, M.A.**, Graue, A., Baldwin, B.A. and Stevens, J. "*Complementary Imaging of Oil Recovery Mechanisms in Fractured Reservoirs*", reviewed proceedings at the 5th World Congress on Industrial Process Tomography, Bergen, Norway, September 3-6, 2007
   Invited for publication and submitted to a special issue of Chemical Engineering Journal

4. **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 the International Symposium of the Society of Core Analysts, Calgary, Canada, September 10-13, 2007

5. Haugen, Å., **Fernø, M.A.** and Graue, A. "*Comparison of Numerical Simulations and Laboratory Waterfloods in Fractured Carbonates*", SPE paper 110368, proceedings at SPE ATCE, Anaheim, CA, USA, November 11-14, 2007

Introduction

The introduction to this thesis is based on three important parts to improve the understanding of oil recovery from fractured reservoirs; numerical simulations of fluid flow in porous media, pore-scale network models and experimental measurements and the interaction between these. The latter is the main focus in this thesis, and most attention will be devoted to experimental results, both in the introduction and in the discussion. The two former parts are important for the understanding of the experimental findings, and are based on experimental observations and bound by the laws of physics. The fact that the numerical models and reservoir simulators are based on observations from hydrocarbon producing fields and laboratory tests demonstrates the close link between the three parts and emphasize the need for interdisciplinary approach to improve the understanding of fractured reservoirs and the predictions of oil and gas production.

Naturally Fractured Carbonate Reservoirs

Naturally fractured carbonate reservoirs are geological formations characterized by a heterogeneous distribution of porosity and permeability. A common scenario is low porosity and permeability matrix blocks surrounded by a tortuous, high permeability fracture network. In this case, the overall fluid flow of the reservoir is strongly dependent on the fluid flow properties of the fracture network, with the matrix blocks acting as the hydrocarbon source. Most reservoir rocks are to some extent fractured, but the fractures have in many cases insignificant effect on fluid flow performance and may be ignored. Naturally fractured reservoirs are defined as reservoirs where the fractures have a significant impact on performance and recovery. Oil production from a fractured reservoir will differ from a conventional reservoir, and some of the most pronounced differences are listed below (Allen and Sun, 2003):

1. Due to high fluid transmissibility in the fracture network, the pressure drop around a producing well is lower than in conventional reservoirs, and pressure drop does not play as important role in production from fractured reservoirs. Production is governed by the fracture/matrix interaction.
2. The GOR (gas-oil ratio) in fractured reservoirs generally remains lower than conventional reservoirs, if the field is produced optimally. The high permeability in the vertical fractures will lead the liberated gas towards the top of the reservoir in contrast to towards producing well in conventional reservoirs. This is to some degree sensitive to fracture spacing and orientation and the position of producers. Liberated gas will form a secondary gas gap at the top of reservoir or expand existing cap.
3. Fractured reservoirs generally lack transition zones. The oil-water and oil-gas contacts are sharp contrasts prior to and during production due to the high fracture permeability providing a rapid mechanism for re-equilibrate fluid contacts.

Recovery Mechanisms in Fractured Reservoirs

Saturation dependent functions such as the relative permeability (k_r) and the capillary pressure (P_c) are key factors for the assessment and prediction of the oil and gas production from a petroleum reservoir. Representative values are preferentially obtained through Special Core Analysis (SCAL) tests, which generally reproduce the reservoir conditions as close in the laboratory, including:

- the thermodynamics (such as pressure and temperature)
- the reservoir stress (overburden and pore pressure)
- the nature of the fluids (synthetic reservoir brine and live crude oil)
- the initial saturation state (low S_w value)
- the wettability (preserved samples from the reservoir or restored wettability through an aging process at irreducible water saturation, S_{wi})

In addition, production conditions (pressure drop and field analogue water injections rates) are also usually matched. Laboratory tests are performed to determine recovery mechanisms in oil producing reservoirs, to measure specific production parameters and to provide data for numerical simulations. In the following several experimental approaches will be presented and discussed relative to previously reported work to provide a background and introduction to the theme of this thesis and a perspective of the scientific challenges.

The impact of capillary pressure

Spontaneous brine imbibition as a recovery mechanism in fractured reservoirs is well established and has been reported by several authors. Counter-current imbibition, where water spontaneously enters a water-wet rock while oil escapes by flowing in the opposite direction, is a key recovery mechanism in fractured reservoirs. The amount of water imbibed depends on the capillary pressure curve, which is closely correlated to the pore structure and the wettability condition of the rock. The wettability determines the microscopic distribution of oil and water in the pore space, and, consequently, how efficient oil is displaced by brine imbibition. The amount of spontaneously imbibed water into an oil saturated rock is ultimately controlled by the capillary pressure curve, or more accurately, the positive part of the imbibition capillary pressure curve. The shape of this curve is dictated by the wettability, as the saturation range where the capillary pressure curve is positive decreases when the wettability tends towards a less water-wet state.

Many of the naturally fractured carbonate fields exhibit mixed-wet or oil-wet wettability preference (Downs and Hoover, 1989), and successful solutions to produce oil in water-wet fields will not necessarily perform as well in oil-wet reservoirs. For instance, the performance of waterflooding to increase recovery in a water-wet fractured reservoir will generally be successful due to favorable spontaneous imbibition. However, in an oil-wet, fractured reservoir, water will not spontaneously displace oil from the matrix, resulting in poor recoveries and early water breakthrough.

The capillary pressure curve is an explicit measure of rock parameters such as pore structure and wettability, and much work has been dedicated to develop methods for capillary pressure measurements. There exist several widely used methods today, but the centrifuge method is perhaps one of the most frequently used methods. The methodology is briefly described in Appendix A.

One concern with the current industry standard centrifuge method is the need to use approximate mathematical solutions to calculate the correct capillary pressure curve from average production data. Depending on the experimental setup used, it is possible to obtain the average endpoint saturation at each rotational speed, or measure the production as a function of speed, or both. The Society of Core Analysis (SCA) completed in 1993 an inter-laboratory survey (15 laboratories world wide) of drainage capillary pressure curve measurement by the centrifuge technique. Laboratory operating procedures were not specified, but it was asked for a detailed description of experimental procedures and intermediate results. The main purpose of the survey was to determine how the analysis techniques used on raw experimental centrifuge data influenced the accuracy in the derived capillary pressure curves. Assuming that acceptable experimental procedures were used, Forbes (1997) concluded that the main source of inaccuracy was related to the interpretation process, not the experimental procedures.

Spontaneous imbibition

Matrix capillary pressure is important in fractured reservoirs as it controls the rate of water uptake from the fracture network into the matrix, and therefore the efficiency of oil displacement by spontaneous imbibition. A standard imbibition test where a rock sample is immerged in brine and the production of oil is measured as a function of time has been used to estimate production by spontaneous imbibition in fractured reservoirs. A method to scale the imbibition curves from laboratory tests on core plugs to the production of oil from isolated reservoir matrix blocks, with various sizes and shapes, has been studied extensively, and several scaling groups have been proposed. Aronofsky *et al.* (1958) proposed an exponential form of the matrix-fracture transfer function, and formulated an important usage of scaling groups: the time to complete a simulation of oil recovery from a fractured reservoir would decrease by several orders of magnitude if the transfer functions for fluid flow between fracture and matrix expressed the rate of imbibition with scaled dimensionless time. Other scaling laws have been proposed by e.g. Barrenblatt *et al.* (1960), Mattax and Kyte (1962) and Kazemi *et al.* (1976). Ma *et al.* (1997) modified the dimensionless scaling group proposed by Mattax and Kyte (1962) to include the effect of viscosity ratios on the rate of spontaneous imbibition.

Although counter-current imbibition is generally believed to be the dominant form of spontaneous imbibition in fractured reservoirs, it has been suggested that co-current imbibition plays a more dominant role than earlier anticipated (Firoozabadi, 2000, Pooladi-Darvish and Firoozabadi, 2000). Co-current recovery is also believed to be faster and more efficient than counter-current imbibition (Rangel-German and Kovscek, 2002). Co-current imbibition may be defined as an imbibition mode where fluids flow in the same direction, along similar flow paths. Using pore-scale modeling, Hughes and Blunt (2000) found that the pattern of displacement and the rate of imbibition was dependent on the relationship between capillary number, contact angle and initial wetting phase saturation. Environments where co-current imbibition prevails are in gravity segregated fractures where only parts of the matrix surface are exposed to water. Karpyn *et al*. (2006) identified three distinct flow intervals during spontaneous imbibition in layered sandstone with a single longitudinal fracture, where counter-current flow was dominant at early and intermediate times, while both co-current and counter-current flow mechanisms coexisted at late times.

Wettability effects on waterflood recovery

The capillary pressure curve, imbibition potential and imbibition rate are all highly sensitive to wettability (Zhou *et al.*, 2000). Li and Horne (2002) proposed a general scaling law where the effect of wettability was explicitly included to compare spontaneous imbibition curves at wettabilities other than strongly water-wet. The imbibition rate should scale according to the cosine of the contact angle; however, even in simple systems like cylindrical tubes, the issue of static vs. dynamic angles arises (Morrow and Mason, 2001). Although it is appealing to represent the wettability in terms of the cosine to the contact angle and apply this directly in the scaling law, the assignment of a single effective average contact angle is not physically correct for systems where there is a distribution of contact angles, such as in naturally porous rocks (Jackson *et al.*, 2003, Behbahani and Blunt, 2005).

Morrow and Mason (2001) stated that the difference in wettability between mixed-wet cores should not be correlated by using a simple wettability factor in the expression for dimensionless time (t_D). They further claimed that the main objective in scaling groups for cores with wettabilities other than strongly water-wet is to adjust the factors in the definition of t_D, without explicitly including a term for wettability; the differences in imbibition rate and displacement efficiency between strongly water-wet and mixed-wet imbibition can then be ascribed to wettability.

The impact of wettability on oil recovery by waterflooding was further demonstrated by Jadhunandan and Morrow (1995). They found that a maximum recovery of oil occurred at moderately water-wet conditions (Amott-Harvey index, $I_{w\text{-}o}$ = 0.2) in Berea sandstone core plugs. This was also found by Zhou *et al.* (1995), who reported the highest recovery by long-term spontaneous imbibition (~50 days) at moderately water-wet conditions in Berea core plugs. Additional evidence for the importance of wettability on spontaneous imbibition was provided by Johannesen *et al.* (2006) that reported a similar trend in chalk. In this crude oil/brine/rock system the maximum recovery was shifted to a wettability index of $I_{w\text{-}o}$ = 0.4 measured by the Amott test. The rate of oil recovery by counter-current imbibition was critically dependent on wettability, but pore structure was dominant over ultimate recovery (Hatiboglu and Babadagli, 2007). Similar observations were reported by Zhou *et al.* (2000), where imbibition rates were lowered with several orders of magnitude when the wettability was changed towards less water-wet conditions.

In a pore-scale modeling approach to better understand the physics behind the wettability impact, Behbahani and Blunt (2005) studied the decrease in imbibition recovery and production rates reported by Zhou *et al.* (2000). They used a topologically equivalent Berea network model and adjusted the distribution of contact angles at the pore scale. They found that the increase in imbibition time for mixed-wet samples was a result of very low water relative permeability caused by low connectivity of water at intermediate saturations. Their approach demonstrated that pore-scale modeling is a useful tool to understand the physics involved with e.g. spontaneous imbibition in mixed-wet cores. The aim of pore-scale modeling is to predict properties that are difficult to measure, such as relative permeability, from more readily available data, such as drainage capillary pressure (Valvatne *et al.*, 2005).

The benefit of modeling the wettability variations, rather than relying on existing empirical models, was further demonstrated by Jackson *et al*. (2003). They used a pore-scale network model in conjunction with conventional field-scale reservoir simulators, and found that the empirical models for predicting hysteresis in the transient zone above the oil-water-contact (OWC) were insufficient if wettability varied with height. A significant increase in oil recovery using scanning curves generated by the pore-scale model was demonstrated.

Capillary continuity in fractured rocks

In addition to spontaneous imbibition, the capillary continuity phenomenon is an important contributor to oil recovery in fractured reservoirs. Capillary continuity, as a recovery mechanism, may provide fluid communication between partially or completely isolated matrix blocks, thus increasing the recovery by gravity drainage or viscous displacement. Capillary continuity increases the height of the continuous fluid column in a reservoir and thereby the recovery of oil, since the gravity drainage efficiency is dictated by the height of the fluid column.

Capillary pressure continuity in vertically stacked matrix blocks has been studied extensively, e.g. by Horie *et al.* (1990), Labastie (1990) and Stones *et al.* (1992). They investigated the properties of materials present in the fracture, the effect of the overburden pressure and the permeability, and how this affected capillary continuity. In 1994, Firoozabadi and Markeset reported a series of experimental results where they varied the fracture aperture and degree of contact between blocks. They observed that the mechanism of desaturation (i.e. decrease of oil saturation in matrix block) was in some cases the forming and breakdown of liquid droplets across the open fracture.

Capillary continuity through liquid droplets

The capillary continuity between isolated matrix blocks may occur through liquid bridges, where the established bridges decrease the capillary retained oil within each small isolated matrix block (Saidi, 1987). An important aspect is the critical fracture aperture, defined as the aperture below which liquid drops may form stable liquid bridges across the fracture. A formula for critical aperture was suggested by Sajadian and Danesh (1998), but it is not clear if this was consistent with the experimental results presented (Ringen *et al.*, 2005).

The concept of capillary continuity is not limited to gravity drainage, and can also play an important role during waterfloods of physically isolated matrix blocks. The forming of liquid droplets on the fracture surface during waterfloods was reported by Graue *et al.* (2001), who observed a dependency of matrix wettability on the formation of water droplets in the fracture. At water-wet wetting conditions other than strongly water-wet, droplets of water formed on the fracture surface and grew at stationary sites before they bridged the fracture to form wetting phase bridges. Based on these results, Aspenes *et al.* (2002) performed a sensitivity study on fracture widths and flow rates to determine the conditions where water droplets transported water across the fracture. The significance of wettability was also demonstrated by Pratap *et al.* (1997) in a numerical study of capillary continuity in vertically stacked chalk matrix blocks during waterflood. They demonstrated the importance of wettability on the transport of oil between matrix blocks separated by a fracture, and found that this occurred only at intermediate water-wet conditions.

The forming of liquid droplets on the fracture surface was further investigated using micro-models by Rangel-German and Kovscek (2006). They learned that some pores were responsible for the uptake of water from the fracture, whereas immediately adjacent pores expelled nonwetting phase (oil or air) from the matrix. Oil escaped the matrix in the form of blobs or droplets that grew into the fracture. In a conceptual droplet detachment model proposed by Gautam and Mohanty (2004), the droplets emerged at the matrix-fracture interface in clusters of large pore throats, and the water infiltration from fracture to matrix was modeled with narrow throats in the vicinity of the oil producing sites. This was consistent with observations reported by Rangel-German and Kovscek (2006), and showed that the size of the oil droplet growing on the fracture surface was sensitive to the fluid flow rates in fracture. The critical size, i.e. the size where a growing oil droplet detaches from the matrix-fracture interface, was also dependent on the flow rate in the fracture.

Matrix-Fracture Transfer in Fractured Reservoirs

It is important to understand the physical processes during the interaction and fluid transfer between matrix and fracture to improve models of multiphase fluid flow in fractured porous media (Gautam and Mohanty, 2004). An improvement to the simulation of gas gravity drainage was presented by Festøy and Van Golf-Racht (1989), where they modeled the contact between isolated matrix blocks by assigning fracture grid cells with matrix properties. The degree of contact was controlled by varying the numbers of fracture grid cells with matrix properties to the total number of grid cells making up the fracture. Another modeling approach was suggested for waterfloods in fractured chalk (Graue *et al.*, 2000), where the model constituted two layers, one layer with matrix properties and one layer with fracture properties. The degree of capillary continuity across the fractures was adjusted by varying the relative thickness of each layer.

Saidi (1990) questioned the reality of using matrix properties in contact points across fractures in actual reservoirs, where overburden pressure and diagenesis effects greatly reduce permeability. He argued that a capillary continuity across fractures could indeed be developed, but then to a much smaller degree, not justifying the use of matrix properties. Defining matrix blocks in a fractured reservoir as discontinuous blocks is appropriate only if the fracture capillary pressure is assumed to be zero (Shariat *et al.*, 2006). The fracture capillary pressure will contribute to fluid communication between isolated matrix blocks and therefore have a larger impact during a gravity drainage process than in a capillary imbibition, as the gravity drainage is dictated by the height of the reservoir, or the height of each isolated matrix block.

The fracture multiphase functions, such as relative permeability and capillary pressure, are often ignored or simplified in simulations of fractured reservoirs. A crude simplification is to use linear fracture relative permeability curves (k_r) and set the fracture capillary pressure (P_c) to zero. The errors introduced when ignoring non-linear k_r curves and non-zero P_c in fractures were demonstrated by de la Porte *et al.* (2005), who suggested a method for selecting the correct set of fracture multiphase functions in a simulation. Their results indicated that using straight relative permeability curves lead to oil-recovery prediction errors as high as 70% in water-oil systems. In gas-oil systems where gas flows into the fractures, oil recovery could be underestimated by a factor of almost two when fracture capillary pressure was set to zero.

In an attempt to further improve simulation of fractured reservoirs, Lu *et al.* (2006) proposed a physically motivated formulation of the matrix-fracture transfer function used in dual-continuum models by decoupling the transfer rate into contributions from fluid expansion, diffusion and displacement. Their model proved better than conventional models such as the Kazemi *et al.* (1976) model, which tends to under-predict transfer between fracture and matrix at early times.

Fracture multiphase functions

The key issue for simulating flow in fractured rocks is to model the fracture-matrix interaction correctly under conditions such as multiphase flow (Wu *et al.*, 2004). Transfer of fluids between fracture and matrix in dual-continuum models is generally upstream weighted (de la Porte *et al.*, 2005), where the upstream weighing scheme calculates the flow of water from the fracture network to the matrix based on water flow properties (relative permeability) in the fracture, rather than the water relative permeability of the matrix near the fracture. No flow of water in the fractures should not necessarily imply no imbibition into the matrix if there are forces present in the matrix to cause imbibition (de la Porte *et al.*, 2005).

Imagine that fracture multiphase functions are included in the numerical model in the form of straight relative permeability and non-zero capillary pressure. The presence of a P_c may change the shape the fracture relative permeability curve away from the linear k_{ri_frac}=S_{i_frac} relationship, and may establish zero relative permeability with non-zero wetting phase saturation in the fracture. Then, based on the concept of upstream weighting, there might be water in the fracture for spontaneous imbibition while the fracture relative permeability to water is zero. The assumption that the imbibition of water from the fracture to the matrix is solely dependent on fracture relative permeability is a simplification of the physics controlling the transfer and physically incorrect (Wu *et al.*, 2004).

The influence of fracture fluid flow

The importance of flow in fractures was recognized by Romm (1966), who after a series of experiments concluded that the fracture relative permeability between two parallel glass plates was a linear function of saturation. However, when reproducing the experiment, applying more sophisticated visualization tools for the measurement of fracture saturation, Pieters and Graves (1994) found that the relative permeability was not a linear function of saturation. Furthermore, Babadagli and Ershaghi (1992) derived an effective fracture permeability under the assumption that there was interaction between matrix and fracture, and showed that the curves are influenced by flow rate, the direction of flow and matrix properties such as wettability, permeability and initial water saturation. Babadagli (1997) also expressed concern of the lack of dynamic spontaneous imbibition experiments in the literature as water will flow in fractures during water injection in fractured reservoirs, and the interface between the water and the rock surface will not be static. He argued that the scaling of capillary imbibition is dependent on the flow rate in fracture; as the flow rate increases, residency time decrease, resulting in a less effective imbibition. Residency time relates to the time a water molecule is exposed to the rock surface, which in turn will influence the efficiency in the imbibition process.

A network model approach to investigate the impact of fluid flow on fracture relative permeability was reported by Hughes and Blunt (2001), where they numerically constructed a fracture based on the aperture distribution from high resolution CT data. They computed the relative permeabilities and residual nonwetting phase saturations in the fracture for different flow rates, and showed how the competition between water advancement in the fracture (piston-like advance and/or flow in wetting layers) and the capillary imbibition of water into the matrix controlled the overall fracture fluid flow. The properties of the matrix adjacent to the fracture were found to play a very important role in controlling the transfer of fluids between the matrix and the fracture.

Further support for the impact of fracture flow on the spontaneous imbibition was demonstrated by Rangel-German and Kovscek (2002), who identified two active spontaneous imbibition regimes in fractured reservoirs, depending on the relationship between water injection rate and the matrix-fracture transfer. In the *filling fractures* regime, the water advance in the fractures was slow relative to the rate of water imbibition into the matrix, leading to oil displaced in a co-current manner. In the *instantly filled fractures* regime, the fractures filled with water fast relative to the rate of matrix-fracture transfer and the imbibition was counter-current.

Results and Discussion

The importance of capillary pressure on spontaneous imbibition in fracture reservoirs has been demonstrated above. Capillary pressure is important in other applications as well, for instance for capillary continuity between isolated matrix blocks to increase fluid communication, and, hence, improve recovery of oil. Generally, the capillary pressure curve is an estimate of the recovery efficiency from mechanisms like spontaneous imbibition, waterfloods and gravity drainage, and it is important that the correct capillary pressure curve is measured in a laboratory test. There exists several methods to obtain this parameter, but only the centrifuge technique will be further discussed. The influence of wettability on the capillary pressure curves and the significance of wettability on recovery from fractured reservoirs in general will also be demonstrated. The scientific papers included in this thesis are labeled Paper 1-5, and will be discussed in the following.

Measuring the Capillary Pressure Curve

The capillary pressure curve in outcrop limestone core plugs were experimentally obtained using the centrifuge method. The wettability preference and permeability of the core samples were found to be the most significant parameters influencing the time to complete the measurements of the capillary pressure curves, and will be further discussed below.

The difficulty in establishing equilibrium time

A common error in centrifuge capillary pressure measurements is to not obtain a good estimate of average saturation at equilibrium in each rotational speed (O'Meara Jr. *et al.*, 1992). Equilibrium at a rotational speed in a centrifuge test may be defined as the saturation where no additional fluid production is observed. The difficulty in estimating the time to reach equilibrium in centrifuge experiments has been discussed by several authors (Hoffman, 1963, Slobod and Prehn Jr., 1951, Szabo 1972, Ward and Morrow, 1987, Fleury *et al.*, 2000). Slobod and Prehn Jr. (1951) discussed equilibrium times for cores with permeabilities ranging from 2 to several hundreds mD. Their high-permeability samples reached, subjectively, equilibrium after 1 to 2 hours of spinning, while average saturation in the low-permeability cores was still decreasing after 20 hours at 18000 RPM. Hoffman (1963) used the centrifuge technique to determine capillary pressure curves in cores with permeability around 60 mD. His criterion for equilibrium was no further observed production within 1 hour after last observed fluid production. In no case did the samples reach equilibrium in less than 24 hours. Szabo (1972) invoked fluid equilibrium after 24 hours in core samples with permeabilities in the range of 6-50 mD, but failed to explain the reason for doing so. **Paper 1** demonstrates the impact of high resolution production measurements on establishing and recognizing fluid equilibrium at a given rotational speed.

Possible explanations to the variable time to reach equilibrium, and why equilibrium is difficult to anticipate in samples with comparable permeability, was reported by Ward and Morrow (1987). A plausible reason was the high degree of fluid connectivity in liquid wedges retained at the corners of pores and in surface roughness in natural porous rocks. The irreducible wetting phase saturation in a well-defined system like bead packs is between 6-8%, caused by lack of hydraulic connectivity of the bulk fluid and thereby lack of capillary equilibrium (Morrow, 1970). The difficulty in estimating the degree of connectivity in natural rock may explain why it is yet not resolved how long a core plug needs to be spun to reach saturation equilibrium.

The recognition of fluid equilibrium during a multi-speed centrifuge experiment using a high resolution camera for fluid production is demonstrated in **Paper 1**. The automated, high resolution imaging system was capable of monitoring flow rates down to 10^{-5} PV/day (15 ml pore volume), and the following equilibrium criterion was used: no additional production observed over a 24 hour period after last observed fluid production. This is a stronger requirement than in the publications reviewed above, especially due to the high resolution used in the production measurements.

The impact of wettability and absolute permeability

Limestone core plugs with variable wettability and absolute permeability were run in the centrifuge to establish the primary and secondary drainage capillary pressure curves during decane/brine displacements. Primary drainage curves were obtained in two strongly water-wet limestone core plugs, while secondary drainage curves were established in three aged core plugs. The time to reach equilibrium at each rotational speed was strongly dependent on the wetting preference of the sample, demonstrated by Figure 1 and illustrated by the large time difference observed to reach stable saturations for each wettability. The petrophysical properties of the cores were comparable, with similar porosity and permeability, thus it is plausible that the difference in time required for equilibrium was directly linked to wettability. In the case of the oil-wet sample, there was a spontaneous displacement of water due to its affinity to decane in addition to the viscous displacement due to the centrifugal force field. An extensive two phase production was observed at lower rotational speeds, resulting in almost 40 days of spinning at 600 RPM for the oil-wet core. Similar tail production for oil-wet cores was also observed in core flood tests, where 10-20 PV of water was injected to reach end point saturations.

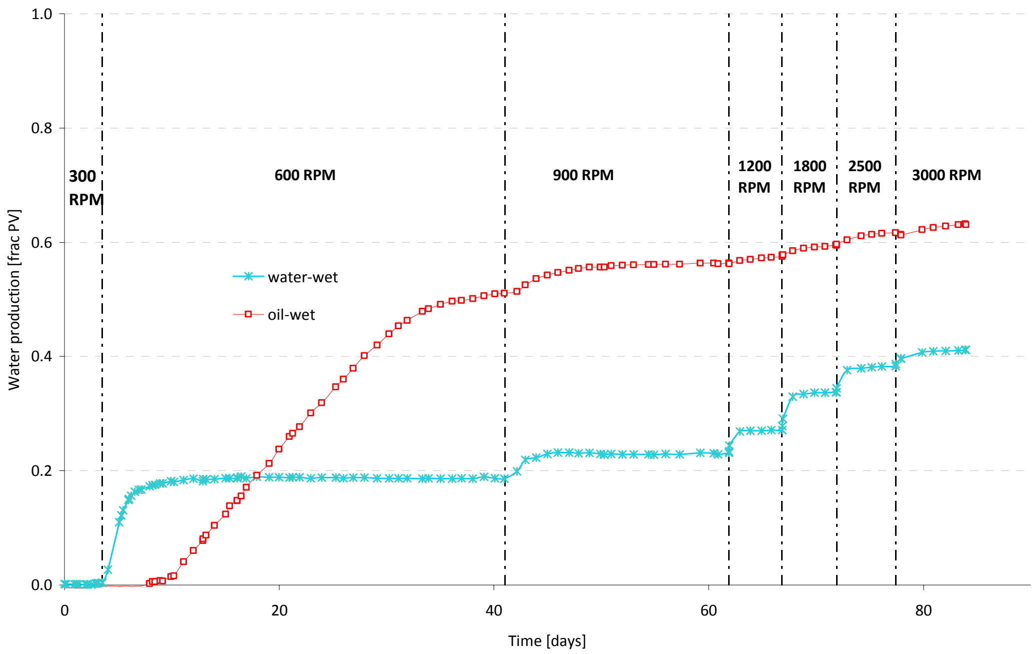

Figure 1. Influence of wettability on the recognition of fluid equilibrium at each increment in centrifuge rotational speed. The red points represent the experimental readings during decrease in water saturation in an oil-wet sample, whereas the blue points are the corresponding measurements for a water-wet core.

The effect of the absolute permeability on the recognition of equilibrium was also investigated in **Paper 1**. Equal absolute permeabilities in two strongly water-wet limestone cores produced similar primary drainage capillary pressure curves, and both cores reached fluid equilibrium practically simultaneously for all rotational speeds. A two-fold difference in absolute permeability between two oil-wet limestone cores demonstrated the impact of permeability, where difference in time to reach equilibrium was observed.

The sensitivity in the automated centrifuge system was an order of magnitude higher than human visual readings, and to reach the same criteria of equilibrium, the laboratory operator would need to wait 10 days with zero manually observed production at each centrifuge speed. The increased sensitivity in fluid production had a significant impact on the recognition of equilibrium, and, consequently, in the time required to complete the tests. The longest time to reach equilibrium in a single rotational speed was 37 days. In this case the entire test took 130 days to complete (7 rotational speeds). Fleury *et al.* (2000) recognized the difficulty in defining a capillary equilibrium and identified the need for a stability criterion for changing the centrifuge speed. They pointed out that this criterion was often set empirically, based on individual experience, and proposed a mathematical model using two exponential functions to fit the measured production and predict stable saturation at each speed. The bi-exponential model reduced experimental time while providing a rigorous criterion to change the speed of rotation of the centrifuge. Although this approach is appealing, and should be considered more frequently to establish a mathematically based criterion for rotational speed change, the resolution in the measurements is vital to produce production data to be used in the calculations.

Calculating the local capillary pressure curve

Although excellent estimates of fluid equilibrium were obtained at each rotational speed, calculations were required to obtain the capillary pressure curve. The correct capillary pressure curve may be calculated from the average production measurements by solving the integral problem associated with these measurements (Forbes, 1997). However, there is no exact mathematical way, neither numerical nor analytical, to find a local function when only the integral is known. The CYDAR (CYDAR, 2008) core analysis software was used to calculate the local capillary pressure curve, applying known approximate mathematical solutions (Hassler-Brunner and Forbes) to the integral problem.

Experimental data points may give non-monotonic capillary pressure curves, e.g. where one water saturation has several capillary pressure values. The standard way to correct this is to move (or remove) the experimental points, and the process becomes operator dependent. In CYDAR, the oscillating points are smoothed using splines with constrain to have a monotonic curve. Figure 2 shows the calculated capillary pressure curves using the Hassler-Brunner and the Forbes solutions, including some of the experimental data points provided in **Paper 1.** The points are raw experimental data, presented without any form of smoothing.

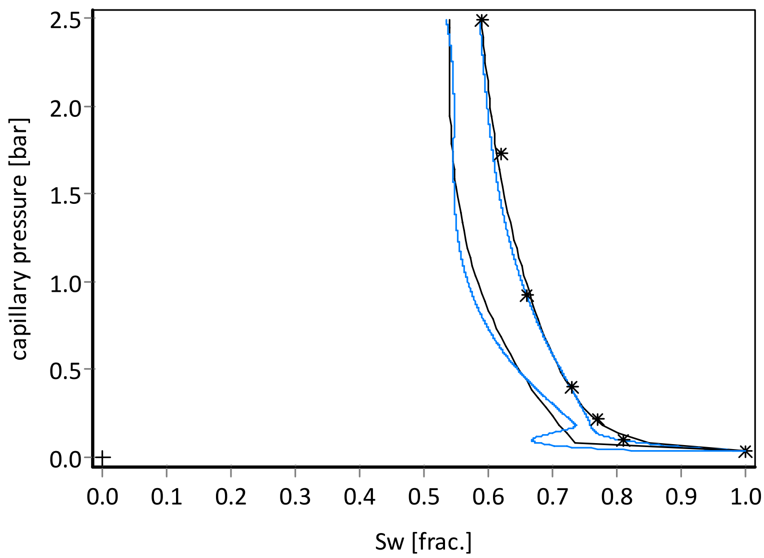

Figure 2. Application of mathematical approximate solutions to experimental centrifuge production data. The points represent the actual experimental readings, whereas the black lines are the results from Forbes method and the blue lines are calculated curves using the Hassler-Brunner solution. The left curves represent the local capillary pressure curves, while the right curves are the back calculated average capillary pressure curves.

The Hassler-Brunner solution is now generally used as an initial guess to the correct solution. This method is highly sensitive to oscillations in the curve, and does not perform well when there are sharp increases in water saturation. The rotational speed table used in the centrifuge test was not optimized with regard to observed production rates, thus the applied speed schedule did not produce the optimal shape in the capillary pressure curve. This will cause trouble for the Hassler-Brunner method, illustrated by the bend in the calculated local capillary pressure curve (left, blue curve).

Forbes' method is better and more versatile than the Hassler-Brunner method, and does not need to smooth experimental data to provide realistic curves. In addition, the method performs well with a minimum of experimental points. A nice feature in CYDAR is that the calculated solution of the integral problem is verified, and provided for the user by choice. The back calculated average capillary pressure curves, using the local solutions provided with each method, are also presented in Figure 2. There is generally an excellent match between the experimental points and the back calculated average capillary pressure curves using both the Forbes and Hassler-Brunner method. The back calculated Hassler-Brunner solution looks accurate, but the shape of the local curve is not realistic for this experiment and illustrates the shortcomings of the method. The Hassler-Brunner capillary pressure curve would most likely look better with smoothing, but then the curve would become operator dependent.

Measuring the local capillary pressure

Generating the local capillary pressure curve directly, without extensive smoothing of experimental data points to use mathematical approximate solutions, is preferable. The local centrifuge capillary pressure curve may easily be found if the local fluid distribution within a spinning core plug in a centrifugal force field is known.

There exist several methods for measuring the capillary pressure directly by measuring the spatially distributed water saturation during, or in conjunction with, a centrifuge experiment. Methods measuring the locally distributed water saturation after the core plug has been removed from the centrifuge rely on static fluid conditions from the time the rotational speed is decreased until the fluid profile is measured outside the centrifuge. To ensure this, different techniques are used, including freezing the saturation or rapid imaging. The DMS method (Baldwin and Spinler, 1998) utilizing the solidification of the mineral oil nona-decane at room temperature to maintain the saturation profile generated at slightly elevated temperature (melting point 22-24°C), while the recently reported GIT-CAP method (Chen and Balcom, 2005 and Green *et al.*, 2007) relies on rapid imaging to reduce the effect of fluid redistribution. The DMS method is briefly described in Appendix A, while the experimental procedure for the GIT-CAP method is found elsewhere (Green *et al.*, 2007). Other methods where the capillary pressure curve is found directly by measuring the water saturation profile include Baldwin and Yamanashi (1991), Chardake-Riviere *et al.* (1992) and Sarwaruddin *et al.* (2000).

To avoid possible fluid redistribution and the limitation in usable fluids during a centrifugation test, Graue *et al.* (2002b) proposed a method to measure the local water saturation during the dynamic operation of a centrifuge. They studied the capabilities of using a nuclear tracer imaging centrifuge (NTIC) method to measure the *in situ* water saturation profile, and demonstrated the benefit of measuring the direct capillary pressure curve in a centrifuge experiment while the core was spinning. The feasibility study also generated comparable curves to the DMS method and the conventional centrifuge method.

The NTIC method represents a recent and improved procedure to obtain centrifuge capillary pressure curves by measuring the water saturation directly in the centrifuge while it is spinning. **Paper 2** reviews important upgrades in the existing experimental setup, and presents a new experimental procedure to improve the NTIC capillary pressure curve. The methodology and experimental procedure are described in detail in Appendix A. The new NTIC capillary pressure curves were compared to other widely used industrial methods, demonstrated in Figure 3. The results illustrate the consistency and the reliability of the NTIC method when comparing primary drainage curves with the DMS and the conventional centrifuge method. Other comparative studies, where the results from a new approach to measure capillary pressure curves is validated by comparing to established methods include, e.g. Graue *et al.* (1999) and Sarwaruddin *et al.* (2000)

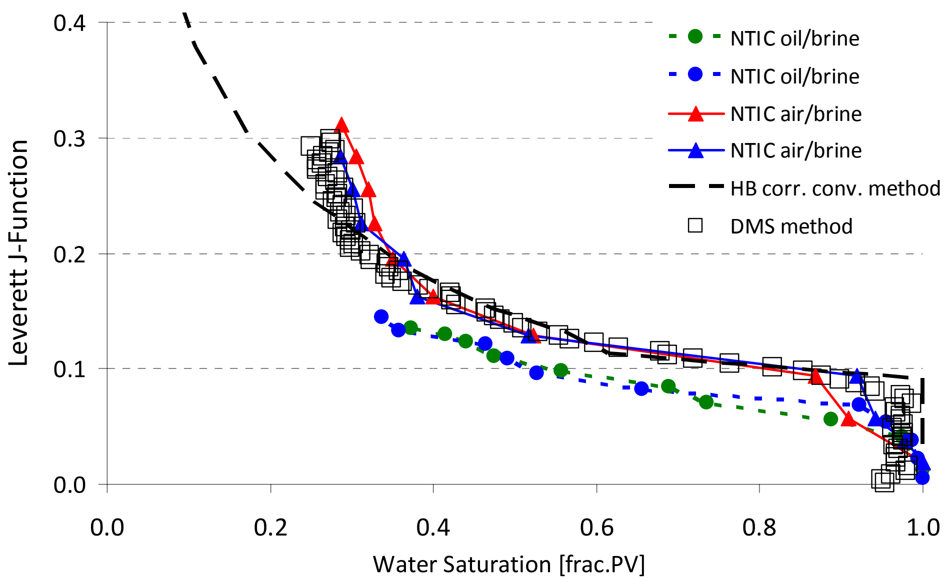

Figure 3. Reproducibility and reliability in capillary pressure curves generated with the NTIC method. Four NTIC capillary pressure curves demonstrate the reproducibility in parallel displacement tests. The similarity between NTIC capillary pressure curves and other methods is also demonstrated when the difference in interfacial tension and core properties are accounted for. The water saturation for the NTIC curves are normalized to largest experimentally observed end face saturation. The DMS and conventional capillary pressure data is previously reported by Graue et al. (1999).

An important premise for the correct interpretation of capillary pressure data is the condition that the capillary pressure is zero ($P_c = 0$) at the outflow boundary (Hassler and Brunner, 1945, O'Meara Jr. and Crump, 1985, Forbes, 1997). Pending liquid drops on the outflow face of the core may displace the $P_c = 0$ condition away from the end face as the droplets lead to a slightly positive capillary pressure at the boundary (O'Meara Jr. *et al.*, 1992). The error introduced when ignoring the pending drops is small, but the presence of liquid droplets may lead to large erroneous capillary pressure calculations in some cases.

The presence of liquid droplets and its influence on capillary pressure and capillary continuity will be further discussed below. Focus will change from how to interpret capillary pressure data to illustrate the presence and importance of capillary pressure in oil recovery from fractured reservoirs. The visualization of core flooding experiments, the forming of droplets and the impacts of capillary continuity in fractured blocks will in particular be discussed.

The Impact of Capillary Pressure in Fractured Reservoirs

The visualization tool used in **Paper 1** provided high confidence experimental data demonstrated by the strong criterion applied when recognizing fluid equilibrium at different rotational speeds. Generally, using visualization tools to obtain local fluid distributions inside the porous media will produce high confidence experimental results and increase understanding of the governing processes during fluid flow. The benefit of measuring the local fluid saturation during a centrifuge test was demonstrated in **Paper 2**, where the saturation profile made it possible to find the capillary pressure directly, without the use of approximate solutions. An increasing number of methods are routinely used to visualize the interaction and fluid exchange between fracture and matrix, e.g. by x-ray imaging reported Tidwell and Glass (1995).

The benefits from complementary imaging

Combining visualization tools with differences in spatial resolutions and rock sample size studied may dramatically increase the overall understanding of the studied phenomena. **Paper 3** reports the use of two visualization techniques, describes the underlying mechanics and the physical basis for each method, and demonstrates the increased knowledge when applying complementary imaging. The nuclear tracer imaging (NTI) technique was developed by Bailey *et al.* (1981) and improved by Graue *et al.* (1990), and utilizes the emitted radiation from radioactive isotopes, individually labeling the fluids to measure the *in situ* fluid saturation profiles during core flood tests. The large dimensions of the rock samples imaged is a strong advantage with the method, for instance enabling the simultaneous study of the impacts from viscous, capillary and gravity forces in a controlled fractured system. The NTI method is used to study the impact of fractures on propagating waterfronts during waterfloods, and its capability to use large samples makes it possible to study different fracture configurations. Magnetic resonance imaging (MRI) provides a visualization tool to study the movements of fluids inside a fracture network, and provides high spatial resolution and fast data acquisition. Both methods are described in detail in Appendix A.

In addition to a detailed description of the two experimental methods, **Paper 3** provides a review of the most important results generated when applying NTI and MRI separately, and the benefits in complementary imaging when studying of the effects from fractures. Previous work present a plausible explanation to the increased recovery above the imbibition potential in fractured reservoirs during waterflooding by wetting phase bridges exerting viscous pressure across isolated matrix blocks surrounded by fractures. The extended viscous pressure was investigated for a range of wettabilities, all on the positive side of the Amott-Harvey index. These results provide the background for the experiments discussed below, and the reader is referred to these publications for details. The same principal thought was applied to a heterogeneous limestone rock type with oil-wet wetting preference in this thesis, where the investigations focused on how the droplets of oil forming on the fracture surface contribute to the communication between isolated core plugs.

Mechanistic similarity

The forming of oil droplets on the fracture surface was investigated in **Paper 4**, where the objective was based on the thought of mechanistic similarity. The hypothesis of wetting phase bridges reviewed in **Paper 3** was tested in a study based on the idea that the forming of oil droplets during oil injection at oil-wet conditions should be mechanistically similar to the forming of water droplets in waterfloods at water-wet conditions. The impact of water phase capillary continuity was illustrated by Viksund *et al.* (1999) during waterfloods in fractured chalk. They used the NTI method to observe that fractures significantly affected water movement during waterfloods at strongly water-wet conditions, while the fractures had less impact on the waterfront at moderately water-wet conditions, where the injected water crossed fractures more uniformly, apparently through capillary contacts. MRI was applied to study the water crossing mechanism more closely, and revealed water droplets forming in the fracture at moderately water-wet conditions, transporting water across the fracture (Graue *et al.*, 2001).

Mechanistically similar to water droplets forming during waterfloods in water-wet chalk, oil was injected in oil-wet limestone cores to observe the forming of oil droplets on the surface (see Figure 4). The locations where the droplets emerge at the fracture surface are not arbitrary, and are likely to be controlled by clusters of larger pores throats. The larger pore throats will reach zero capillary pressure before pores with narrower throats and, hence, the droplets will emerge at these locations.

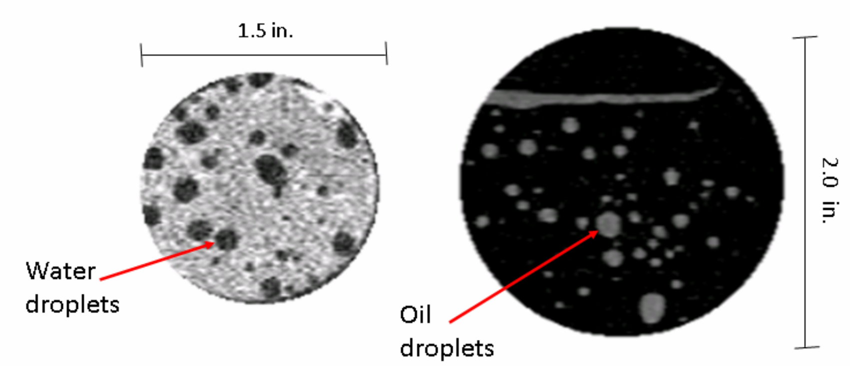

Figure 4. Droplets forming on the fracture surface illustrating the mechanistic similarity. The left cross-section demonstrates water droplets forming in the fracture plane during waterfloods at water-wet conditions in stacked chalk core plugs. The oil-wet limestone cross-section on the right illustrates the droplets of oil forming in the 1mm aperture between stacked cores under an oilflood.

In the conceptual model proposed by Gautam and Mohanty (2004), the oil droplets emerged at the matrix-fracture interface in clusters of large pore throats, and, in accordance with the experimental observations made by Rangel-German and Kovscek (2006), the water transport from fracture to the matrix occurred via narrow pore throats in the vicinity of the oil producing locations. The oil droplet growth process was intermittent, i.e. a blob starts to grow, is displaced by a new blob that starts to grow at the same location and detaches from the fracture surface.

The objective in **Paper 4** was to experimentally investigate the validity of the wetting phase bridge capillary continuity, observed during waterfloods in water-wet chalk, in stacked oil-wet limestone rock samples. The motivation behind the experimental approach was to find out if oil droplets formed on the fracture surface during oilfloods, and, if so, would they bridge the fracture to create liquid bridges for oil transport and reduce the capillary retained oil in the hold-up zone. This is important for gravity drainage in oil-wet, fractured reservoirs. The experimental setup used constituted two stacked oil-wet limestone core plugs separated with a 1 mm vertical aperture, and is further discussed in Appendix A.

Oil phase capillary continuity

The possibility to form oil phase capillary continuity with oil droplets was studied during oil- and waterfloods through stacked oil-wet limestone core plugs. Oil emerged as droplets at the surface ahead of the moving oil front during oilfloods, while oil droplets remained on the fracture surface after water displaced the oil initially in the fracture during similar waterfloods at oil-wet conditions. The stability in the water droplets reported by Graue *et al.* (2001) was not observed for the oil droplets in **Paper 4**, as the intermittent oil droplet growth process reported by Rangel-German and Kovscek (2006) was observed; oil droplets grew larger with time, detached from the fracture surface and floated to the top of the fracture due to buoyancy. This suggests that the droplets did not connect across the fracture to act as wetting phase bridges. This is also supported by the lack of observed change in oil saturation in the outlet core plug ahead of the injecting front.

Oil was also injected through stacked strongly water-wet limestone core plugs to investigate the impact from wettability and the significance of wetting affinity between injected fluid and fracture surface on the forming of oil droplets. No oil droplets were observed in the fracture during oil injections at water-wet conditions. The hydraulic pressure in the fracture was measured during both waterfloods and oilfloods at oil-wet conditions, and the pressure development demonstrates the mechanistic difference when there is a wetting affinity between the fracture surface and the injecting fluid phase. During waterfloods, the fracture hydraulic pressure demonstrated the need to overcome a threshold value before the water invaded the outlet core, while no pressure increase was observed during oil injection, demonstrating the spontaneous nature of the transport of oil.

Injection rate dependency and stability in droplet position

The dependence of flow rate on oil droplet growth reported by Gautam and Mohanty (2004) should also apply on the experimental results reported in **Paper 4**. However, the influence from flow rate will be more pronounced in their experimental setup, as the injected water will not increase the viscous pressure in the fracture. Furthermore, water is injected perpendicular to the direction of the growing oil droplets, which will add to the flow rate sensitivity, as a higher injection rate may remove the droplets from the surface when they are smaller. No flow rate dependency was observed with regard to the capillary pressure continuity studied in **Paper 4**.

The dynamics of fracture droplets growth and the dependency on flow rates were investigated in a separate test with a similar experimental setup. Based on the range of flow rates investigated (0.3 ml/h to 3.6 ml/h), there was clearly an injection rate sensitivity on the size of the oil droplets formed during oil injection. However, a high flow rate did not limit droplet growth by removing growing droplets from the surface, as reported by Gautam and Mohanty (2004), but the limitation was due to reduced droplet growth time. This is the time from when the first injected oil reaches the fracture to the injecting front fills the fracture with oil, and is sensitive to wettability and degree of spontaneous attraction of fluids. In accordance with **Paper 4**, the oil droplets did not form stable liquid bridges across the fracture. During the low injection rate it was easier to observe that there was stability in the location where the oil droplets emerged at the fracture surface. Oil droplets appeared at several locations at the fracture surface, and the intermittent behavior reported by Rangel-German and Kovscek (2006) was observed. The intermittent droplet production development is illustrated in Figure 5.

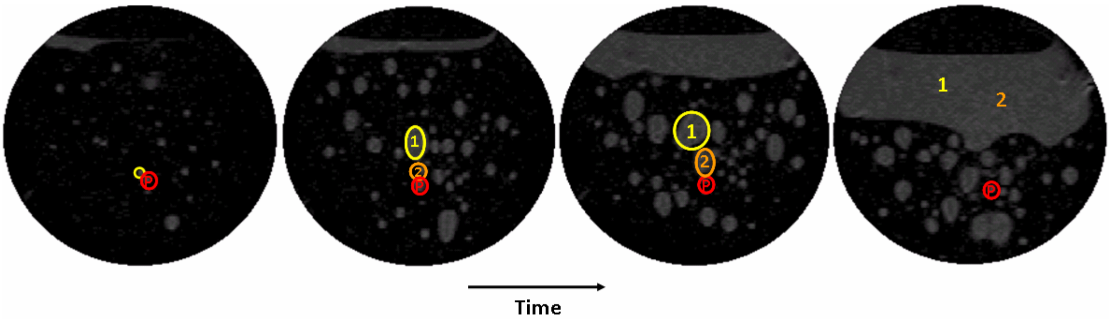

Figure 5. The intermittent droplet production and stability in oil droplet emerge position in the fracture cross-section. There was stability in where oil droplets emerged at the fracture surface. The red highlighted area is an example where an oil droplet initially appears at the surface. The droplet grows (depicted in yellow), and detaches from the surface to migrate towards the top of the fracture. A second oil droplet (orange) starts growing in the same position. This behavior repeats itself throughout the whole injection until the injecting front with oil fills the fracture from the top.

The results show a flow rate dependency in the size of the droplets of oil forming on the vertical fracture surface at oil-wet conditions, and that the droplets emerging point was stable throughout the test. The stability in droplet location on the surface was also reported by Aspenes *et al.* (2007), where the water droplets bridged across the fracture to transport water into isolated matrix blocks. In this case, there will be stability due to two connection points across the fracture.

Modeling Capillary Pressure Continuity

The general application of the discrete-fracture modeling of a reservoir is limited due to the computational demand and the lack of proper knowledge about fracture and matrix. This approach is preferable, however, when reservoir properties are well described, such as in a laboratory experiment (Wu *et al.*, 2004). A numerical model of an experiment is a useful tool to further study sensitivities in the experimental results, as a simulation often is faster and a less expensive way to study a problem. High quality experimental data increases the match between the simulation and the experiments.

A model for fracture capillary pressure was presented by Firoozabadi and Hauge (1990) based on the Young-Laplace equation of capillarity and on the relationship between the capillary pressure, the geometry of the interface between liquid and solid in the fracture and the effect of boundary condition. Saidi (1991) argued that fracture capillary pressure and relative permeability used by Firoozabadi and Hauge (1990) were not experimentally verified, and pointed out that only the average oil production and not the saturation profiles was matched during simulations. By matching both there will be an increased confidence in the simulated results. This will be demonstrated below, and the importance of capillary pressure continuity.

Capillary contact

An attempt to model the experimentally observed oil phase transport across the fracture during oilfloods at oil-wet wetting conditions in stacked limestone core plugs using the Sendra (Sendra, 2007) core analysis simulation software was presented in **Paper 4**. The lack of pressure increase when oil entered the outlet core was interpreted as a spontaneous transport of oil across the open fracture. This was ascribed to the wetting affinity between the injected oil and the fracture surface on the outlet core, i.e. the fracture surface was oil-wet. The experimental pressure development was reproduced in the simulator by assigning a slightly negative capillary pressure curve in the fracture. This is generally performed to account for matrix contact across the fracture, such as touching points in rough fracture surfaces or partially filled fracture with porous or non-porous material. The aperture was in this case explicitly held open to ensure no matrix contact between the cores. A straight curve was used for simplicity. The influence of fracture relative permeability was also investigated, but proved to be less importance in this experimental setup.

Variable capillary contact

The matrix flow for an ensemble of blocks will ultimately depend on hydraulic connection of individual matrix blocks across fractures (Glass *et al.*, 1995). This was investigated in **Paper 5,** where a commercial available field scale simulator (Eclipse) was used to model experimental results from a waterflood in an ensemble of water-wet limestone matrix blocks. The blocks were separated by a defined fracture network with various apertures and orientations. A 3D numerical representation of the experiment was used to investigate the influence of fractures on propagating waterfronts during water injection, and to study the presence and impact of capillary pressure continuity across fractures.

The amount of experiment data available was beneficial when building the numerical representation, especially the combined information of average production and the *in situ* development of water saturation during water injections. The steps to match the simulated and experimental results from a waterflood with a fracture network separating matrix blocks are listed below. The network of fractures was well defined, and properties such as orientations, lengths and apertures were known.

1. Represent the whole rock sample numerically. Honor rock properties such as porosity, permeability, pore volume and physical dimensions of the block.
2. Reproduce the experimental conditions including initial fluid saturations, injection rates, boundary and experimental conditions.
3. Match the experimental results in the waterflood of the whole block by adjusting the matrix multiphase functions in the numerical model. Match the average production and the locally observed displacement pattern.
4. Do not alter the generated matrix capillary pressure and relative permeability curves when a satisfactory match is obtained. Include the fracture network in the numerical model, represent the fractures explicitly.
5. Match average production and the *in situ* development of the waterfront in the fractured case only by adjusting the properties of the fracture multiphase functions. Do not adjust the matrix multiphase functions.

This approach ultimately ensured a good match between the numerical model and the experimental results. The fracture capillary pressure was initially set to zero, which provided a good match of the experimental average production. However, the local displacement pattern match between numerical and experimental data was poor. This result discarded the assumption of zero fracture P_c, as it was plausible that matrix contact points could have formed during assemble of the various matrix blocks. An improved match between the model and experiment was achieved when a slightly positive capillary pressure curve was assigned to the fractures. The two cases are shortly described below.

Absence of fracture capillary pressure

The initial representation of the fracture network constituted 1) zero capillary pressure and 2) relative permeabilities as linear functions of saturation, with no irreducible or residual water saturation. This representation generated a block-by-block oil displacement pattern during the waterflood, and the average production curve coincided with experimental data. The brine saturation development predicted by the simulations was similar to displacement patterns observed by Viksund *et al.* (1999) during waterfloods at water-wet conditions of fractured chalk block. It did not, however, match the experimental results with respect to the *in situ* fluid saturation development.

Presence of fracture capillary pressure

This representation constituted 1) variable, slightly positive capillary pressure curves in the fracture between matrix blocks in contact and 2) relative permeability linear functions of saturation. The variable capillary pressure was justified by likelihood of contact points between the adjacent matrix blocks (grain-to-grain contact) for fractures with small apertures. The capillary pressure was varied until a match between experimental and simulation was found. The linear relation in the relative permeability curve was a crude simplification, but the effect of this was small with the applied experimental flow rates and boundary conditions. The fracture capillary pressure curve was several orders of magnitude weaker than the matrix capillary pressure, and reflected no irreducible or residual saturations. This approach successfully matched the observations of the *in situ* water development in the experiment.

These results illustrate the importance of understanding the presence of fracture, and that a small scale phenomenon like fracture capillary pressure has a great influence of matrix flow.

Conclusions

The capillary pressure curve has been measured using a high resolution automated camera for production measurements, improving incremental volume measurements by an order of magnitude when compared to human visual readings: to reach the same criteria of equilibrium using the manual visualization method, the laboratory operator would need to wait 10 days with zero observed production at each centrifuge speed. The increased sensitivity to fluid production had a significant impact on the recognition of equilibrium and consequently in the time required to complete the tests. Experimental spinning time varied from a few days to over a month at some rotational speeds.

A recent methodology to measure the capillary pressure directly, without the extensive use of approximate mathematical solutions has been reviewed, and improvements and upgrades have been implemented. The NTIC (Nuclear Tracer Imaging Centrifuge) method measures the locally distributed fluid saturation during centrifugation. The reliability and reproducibility in NTIC capillary pressure curves have been demonstrated, and showed excellent coincidence when compared to results from other existing centrifuge methods.

The study of impact from wettability on multiphase fluid flow in fractures in stacked core plugs has been extended to include oil-wet wettability conditions. The forming of oil droplets of the fracture surface at oil-wet conditions mechanistically corroborated the results previously observed when waterflooding chalk at water-wet conditions. During oil injections the oil crossed the fracture apparently through capillary pressure contacts by oil droplets, without associated pressure increase.

The importance of capillary continuity was further investigated by combining experiments and numerical simulations. Recovery mechanisms in fractured carbonate rocks were investigated by comparing 2D, *in situ* laboratory waterflood data of developments in fluid saturations to numerical simulations of the experiment. The results show how the degree of capillary contact between matrix blocks controlled fluid saturation development and influenced the waterflood oil recovery in fractured limestone. Sensitivity studies on the degree of capillary contact over fractures showed this to be the most significant parameter for the frontal propagation during waterfloods. Numerical simulations matching not only the material balance, but also the dynamic local *in situ* saturation development, together with experimental data gave increased understanding of the waterflood oil recovery mechanisms in fractured carbonate rock.

Future Perspectives

The work in this thesis has focused on the influence of capillary pressure, both as a vital input parameter in simulations to describe fluid flow in the reservoirs, and as a dominant multiphase function for important recovery mechanisms in fractured reservoirs such as spontaneous imbibition and gravity drainage. With respect to measuring the capillary pressure and obtaining the capillary pressure scanning curve, **Paper 1** shows the benefits when using an automated, high resolution visualization tool for production measurements in a conventional centrifuge approach, where a saturated core plug is spun at different rotational speeds. **Paper 2** reviews a recently proposed centrifuge technique to measure the capillary pressure directly, without the need to use approximate mathematical solutions. The natural next step, to further increase confidence in this new technique, would be to combine the two approaches reviewed. Implementing a high resolution camera in conjunction with the Germanium detector already in place for internal saturation measurements would increase the ability to compare average production capillary pressure curves to the curves generated by direct measurement, since the curves are measured on the same sample, simultaneously. Also, more data should be generated covering a wider range of fluid displacements, including the imbibition curve, and the applicability to other rock types and wettabilities should be demonstrated. The lack of upholding the boundary condition at the outflow face should also be investigated more thoroughly.

The study of impacts from capillary pressure at various wettabilities was studied in **Paper 4**, and represents important work related to understanding multiphase flow in fractured reservoirs. There are many aspects discussed during this thesis that will be interesting to study in more detail in the near future, and some of the thoughts presented here are already materializing. An important aspect is to study more realistic and tortuous fracture networks, with and without escape fractures. Such fracture networks are possible if slightly larger rock samples may be implemented in the MRI. A larger range of wettabilities and fluids should be applied, more specifically; surfactants should be implemented to study the wettability reversal efficiency of surfactants during an actual flooding though a fractured rock, rather than only at static conditions with a core immerged in surfactant with infinite accessibility. Also, surfactant treatment of fracture surfaces in contradiction to surfactant injection in the matrix should be further investigated. The visualization capabilities of the NTI and the MRI, reviewed in **Paper 3**, provide excellent tools for this approach. This work is partially started, but not included as a part in this these. Some of these papers are listed in Appendix A, and referenced in the list of Additional paper published during the PhD project.

As a link between the work in **Paper 4** and **Paper 5**, pore scale modeling should be considered as a tool to calculate more accurately the capillary pressure and relative permeability curves in the fracture in the presence of growing liquid droplets. This would increase the confidence in the applied multiphase functions, and strengthen the overall physical understanding of flow in fractured rocks. The derived multiphase functions should be implemented in the numerical model, and the errors by not accounting for this should be understood and quantified.

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Appendix A

Additional papers published during the PhD project

- **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*", to be presented at the International Symposium of the Society of Core Analysts, Abu Dhabi, October 29-November 2, 2008

- Graue, A., Bognø, T., **Fernø, M.A.** and Baldwin, B.A. "*Direct In-Situ Centrifuge Capillary Pressure Measurements*", 2008, submitted to <u>Transport In Porous Media</u>

- Haugen, Å., **Fernø, M.A.** and Graue, A. "*Numerical simulation and sensitivity analysis of in-situ fluid flow in MRI laboratory waterfloods of fractured carbonate rocks at different wettabilities*", to be presented at the SPE ATCE, Denver, CO, USA, September 21-24, 2008

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Experimental Methods

The experimental methods used in this thesis are reviewed and described below. In addition, the limestone rock material is briefly described.

Rock material

Reservoir analogues cores are used when rock material from the reservoir is not readily available, and are often drilled from geological formation exposed to the surface. Several outcrop carbonate limestones were considered as a rock material basis for this thesis. An important criterion was the presence of heterogeneity, but the level of heterogeneity should not exceed the point where reproducible results in identical test were not realistic. After close consideration, and in combination with other research groups (Dr. Norman Morrow, University of Wyoming and Prof. Jill Buckley at Socorro, New Mexico), it was decided to move forward with the Edwards GC (Green County) limestone. This is an outcrop limestone from a quarry in Texas, USA. More detail is found in Fernø (2005) and Tipura (2008)

Wettability alteration of outcrop cores

Outcrop rock samples are strongly water-wet and have not been exposed to crude oil. Crude oil is generally used to change the wettability of the originally strongly water-wet sample to a more representative wetting preference for a given reservoir. Imagine that when crude oil invades a pore fully saturated by water, the rock surface is coated by a thick wetting film of water due to its water-wet nature. When a critical capillary pressure is exceeded, the water films rupture, resulting in direct contact of the crude oil with the pore wall and the wettability is changed. Graue *et al.* (2002a) presented an aging methodology to reproduce the obtained wettability in outcrop chalk by flushing crude oil through the rock sample at a low rate sensitive to the cross-sectional area of the sample. The aging technique was further developed, and the stability of the obtained wetting preference in a rock sample was validated by Aspenes *et al.* (2003).

To change the wettability in the outcrop, strongly water-wet limestone rock samples, the cores were aged in crude oil with the aging method presented above, and oil-wet wetting preferences were established. The stability of the obtained wetting preference was validated by three subsequent Amott-Harvey wettability tests on the first set of cores aged, and then it was assumed that for all the preceding cores that the wettability would not change during repeated flooding cycles.

Nuclear Tracer Imaging

The Nuclear Tracer Imaging (NTI) method measures the intensity of γ-radiation from isotopes dissolved in one or more of the fluids present. For imaging fluids in porous rocks, the choice of radioactive tracers should be determined following consideration of predominantly three aspects: 1) high energy to penetrate rock samples and surrounding pressure chamber, 2) sufficiently long half life compared to the length of the experiment to minimize correction due to natural decay, and 3) the tracer should be soluble in only one of the fluid phases. Based on these aspects, $^{22}NaCl$ is found to be best suited tracer. In a multi-tracer experiment, two or more radioisotopes are used simultaneously and the various γ-tracers are identified by their characteristic γ-emitting energies. In general, in system where n phases are to be identified, n-1 tracers are needed. Isotopes used in recent studies are listed in Table A1.

Table A1: Properties of commonly used isotopes

Isotope	Half-Life	Energy γ_1	Energy γ_2	Labeled Phase
Na^{22}	2.6 years	511 keV	1275 keV	Water
Co^{60}	5.3 years	1173 keV	1333 keV	Water
Fe^{59}	45 days	1099 keV	1292 keV	Oil

One of the advantages of using nuclear tracers is its impassive nature with respect to the delicate network of pores, assuming that absorption is minimized by preflushing with non-radiation brine. The possibility to perform multiple experiments on the same rock sample allows for experimental reproduction and investigation of impacts on flow- and recovery mechanisms from a single parameter (e.g. injection rate, wettability or fracture). Also, the NTI technique has the capability of imaging the 1D *in-situ* oil production in cores up to 2 m in length, thus minimizing the disturbance from capillary end effects, and enabling large scale gravity drainage experiments with local saturation measurements.

Saturation and dispersion measurements

Saturations are found from the linear relationship between the number of disintegrations and the saturation of the labeled fluid by

$$S_w = \frac{D - B}{D_{100\%} - B} \qquad \text{(Eq. A1)}$$

where *D* is the number of disintegrations recorded (radiation intensity) at a given point and *B* is the number of background counts without the tracer present. $D_{100\%}$ represents the radiation intensity when the core is fully saturated with radioactive brine.

For a block experiment, the radiation intensity at S_w =100% is a measure of the local porosity variations and generates a 2D porosity field plot of the whole block. Radioactivity is a spontaneous nuclear phenomenon insensitive to temperature and pressure with statistical uncertainty given by $\Delta D=1/\sqrt{D}$, thus, uncertainty will decrease with increased counting time and/or tracer concentration. The counting time needed to obtain a sufficiently low uncertainty is greatly reduced when using higher tracer concentration. A compromise between tracer concentration and counting time is found based on the aim of each experiment. Uncertainties for an arbitrary point of saturation will generally be in the range of 3-5 percent, and the average saturation from NTI usually matches the material balance within 3-4 percent. It is important to note that these 2D saturation images do not capture the saturation development inside the fracture(s), nor do they represent a snapshot of the saturation distribution in a strict sense, as the saturation will change while scanning. The experiment is usually designed so this time delay is of minor significance. More detail of the NTI is found in **Paper 3.**

Methods to generate capillary pressure

The automated high resolution conventional centrifuge method

The centrifuge method consists principally of rotating a saturated core plug at different rotational speed, and measure the expelled fluid. The experimental setup in one laboratory might be slightly different to the next, but generally the centrifuge method has the capability to reproduce reservoir overburden pressure, temperature and fluids. The capillary pressure curves presented in **Paper 1** were generated using a standard Beckman JB-6 centrifuge, with a rotor capable of swinging four core holders simultaneously. Each core had a confinement pressure and the rotational speed table was set before the experiment started. The main advantage with the centrifuge experimental setup compared to other conventional centrifuge systems was the high resolution camera used to measure production. The production measurements were performed automatically, with a preset frequency, using a digital line camera set normal to the plane of rotation and orientated along the axis of the centrifuge cup. A detailed description of the camera is found in **Paper 1**. Data acquisition frequency was high at early times, when oil production rates were high, and decreased as time progressed. An image of the experimental setup is shown in Figure A1.

Figure A1. Automated centrifuge system with a standard centrifuge, a high spatial resolution camera for production measurements and a computer for running the software and storing data. Each production measurement is fully automated, reducing the need to supervise the experiment and limits biased experimental readings.

The DMS method

The DMS method was not explicitly used to generate capillary pressure curves in this thesis, but provided a standard when validating the capillary pressure curves from the NTIC method, described below. The DMS method measures the capillary pressure directly using a centrifuge and MRI (Magnetic Resonance Imaging) for saturation measurement, utilizing differences in echo spinning properties and hydrogen density (Baldwin and Spinler, 1998). The DMS method establishes a fluid distribution in a core plug during centrifugation, solidifies the oil phase (nona-decane, solidifies at 27°C) during spinning to prevent phase redistribution during deceleration and measures the *in situ* fluid saturation profile with MRI. More details may be found in Baldwin and Yamanashi (1991), Baldwin and Spinler (1998) Spinler *et al.* (1999) and Bognø *et al.* (2001).

The NTIC method

The NTIC method is based on the same principals as the NTI method described above, and utilizes the emitted radiation from a radioactive brine saturated spinning core sample to quantify the amount of water present at various distances from rotational centre. A one dimensional water saturation profile, with a spatial distribution of 6 mm, provides the basis for the capillary pressure curve. The capillary pressure at each location is calculated, and the local capillary pressure curve is found directly. The main advantage with the NTIC method compared to other methods for direct measurements of saturation like the DMS (Baldwin and Spinler, 1998) and a similar method reported by Chen and Balcom (2005), is that there is no need to remove the core from the centrifuge to calculate the locally distributed water along the length of the plug.

The method was introduced by Graue *et al.* (2002b), and **Paper 2** reports key upgrades, including a germanium detector with better energy resolution, a lead collimator to reduce background noise and a gating device installed to further reduce unwanted radiation during rotation. A schematic showing the experimental setup is presented in Figure A2, and illustrates the various parts installed to provide better measurements of fluid saturation. A standard Beckman JB-6 centrifuge shaft has been modified to include a gating device to control the operation of the detector within a single rotation. Only one core is spinning in the centrifuge, and the gating disc provides a mechanism to reduce the background radiation in each rotation by shutting down the detector when the core is not positioned directly under it (in a 40° sector). A more detailed description of the various parts installed in the centrifuge may be found in Sukka (2004) and Bull (2007).

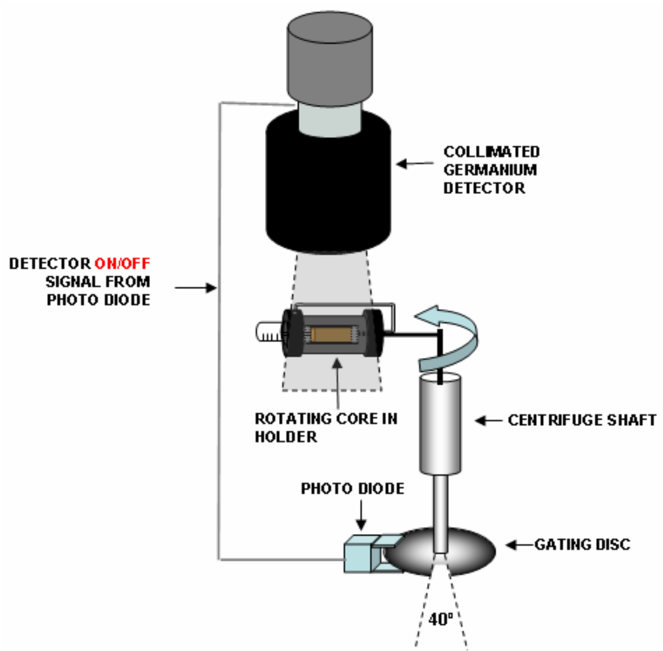

Figure A2. Schematic over the NTIC method experimental setup. The centrifuge method relies on emitted radiation from a spinning core registered by the detector that is used to calculate the spatially distributed fluids. The capillary pressure is calculated by the variable distance from the centre of rotation.

NTIC experimental procedure

Paper 2 also provides additional steps in the experimental procedure reported by Graue *et al.* (2002b), including a rotational speed calculation and a calibration procedure to compensate the variable detector exposure time. The new NTIC experimental procedure is listed below:

1. Saturate the rock sample. Rock samples used in the NTIC method must be saturated with a brine containing a radioactive isotope in a miscible flood at $S_w = 1.0$. A fully brine saturated ($S_w = 1.0$) core plug is mounted in a centrifuge core holder, with a net confining pressure and flushed with 5PV of non-radioactive brine to saturate potential salt adsorption areas. The core is then saturated with the radioactive tracer in a miscible displacement between brine and radioactive brine at a slight backpressure to minimize any air.
2. Calculate rotational speed. A single rotational speed is theoretically needed to generate the entire primary drainage capillary pressure curve. It is important that the rotational speed is sufficient to reach irreducible water saturation at the inlet of the core. This speed may be calculated from the Leverett J-function.
3. Obtain normalization profiles. A one-dimensional intensity profile at static conditions (0 RPM) is obtained to confirm complete mixing between initial brine and radioactive brine. This intensity profile is also used to identify core porosity heterogeneities, but is not used in the calculation of saturation. Before the primary drainage process is initiated, an intensity profile at the calculated rotational speed in step 2 is obtained at $S_w = 1.0$ (valves closed to

prevent fluid production). This profile is used in the calculation of saturation during the following primary drainage.

4. Calibrate shape. The shape of the two intensity profiles (at 0 RPM and at the calculated rotational speed) is compared when the variable detector exposure time at each location is accounted for by the correction coefficients. The shape of the two profiles should coincide. Discrepancies indicate confinement pressure fluid leakage or outlet end piece leakage. If this is the case, re-mount the core in the holder and flush more radioactive brine with backpressure through the core.
5. Initiate the primary drainage. If the shape, when corrected, between static and spinning intensity profiles coincide, open the valves and initiate the primary drainage. If oil is used to drain brine from the core, confirm proper fluid circulation. Use balanced core holders if needed and bring centrifuge up to the rotational speed found in step 2.
6. Identify fluid equilibrium. When fluid production terminates (observed visually with the aid of a stroboscope), the radiation from each point along the core is obtained with the detector while the core is spinning. Two scans are usually obtained, with some time apart, after equilibrium is established to ensure that no additional fluid production is observed.
7. Calculate capillary pressure and saturation. The locally distributed water saturation is calculated by normalization of the intensity profile obtained at spinning conditions and the profile generated at $S_w = 1.0$ (in Step 3). 10 points are normally generated on a 6cm long core. The capillary pressure at each location is calculated.

Magnetic Resonance Imaging

The MRI instrument is used in **Paper 4** to obtain information about fluid movement inside fractures during fluid injections and is located in the ConocoPhillips Technology Center in Bartlesville, Oklahoma, USA. The super conductive magnet induces a static magnetic field with strength 2 Tesla, and operates at a resonance frequency for hydrogen at 85.7098 MHz. High quality saturation profiles (S/N>30) are generally acquired within 20-30 seconds. Images of two-dimensional slices, either within the fracture plane or aligned parallel with the flow direction are acquired within 8 minutes, with four averages. A full 3D representation of the composite core system is generally performed to capture the complete saturation distribution, but the use of 3D during the flooding experiments is limited due to the fast imaging required during flooding limited. Therefore, 3D images were only acquired before and after the experiment for comparing MRI intensities in 2D- and 3D regions. Signal averaging was performed to improve signal-to-noise. To distinguish between the two liquid phases, water and oil, the regular brine is exchanged with D_2O brine. D_2O is insensitive to magnetic resonance and reveal no signal above the background level (detected as black dots on the MRI images).

The MRI system generally consists of the core sample, a core holder to maintain overburden pressure, and the MRI to monitor the distribution of water and oil. Fluorinert (FC-40) is used as the confinement fluid since it is not imaged in the MRI and minimize RF due to its low dielectric properties. The core holder is also made of composite material making it transparent to the RF pulses in the MRI. For the stacked limestone cores, however, the core plugs have been confined using epoxy coating. Schematic over the experimental setup is provided in Figure A3. The epoxy has proven to hold pressures up to 8 bars, and allows for pressure measurement inside the fracture by inserting pressure ports through the epoxy rim. Fractures can easily be identified as these initially are filled with either oil or D_2O. The latter can be identified as an area with low signals, while the former appears as an intense narrow band. Regional saturations are found from the linear relationship between MRI intensity and oil saturation. The MRI intensity is not perfectly linear over the entire saturation range, but a good linear relationship is found between irreducible water saturation and residual oil saturation.

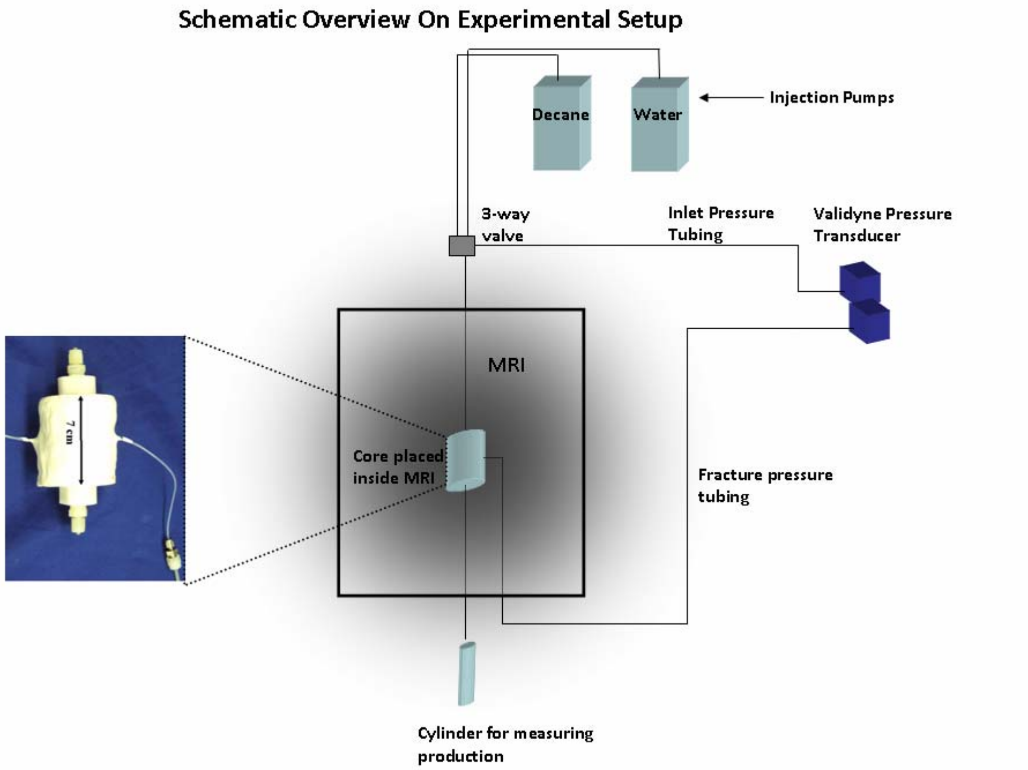

Figure A3. MRI experimental setup schematic.

Experimental setups to study droplet growth

The droplet growth phenomenon is highlighted during the discussion of **Paper 4,** where the results are compared to similar observations made by other authors. It is important for the reader to understand the differences in the experimental setups used, and how these differences impact the results. Figure A4 shows schematics of the experimental designs used to study droplet growth on the fracture surfaces reported by authors discussed in this thesis. The stacked core plugs approach in **Paper 4** was adopted by Graue *et al.* (2001), and will ultimately force the injected fluids to enter the outlet plug due to the lack of alternative outlets. This will force a pressure increase in the vertical fracture to become unrealistically high, and an escape fracture was therefore introduced to limit the viscous pressure drop over the fracture (Aspenes *et al.,* 2007). These setups will favor co-current imbibition of water