IMPACTS ON OIL RECOVERY FROM CAPILLARY PRESSURE AND CAPILLARY HETEROGENEITIES

by

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A dissertation submitted to the Department of Physics and Technology at the University of Bergen in partial fulfilment of the requirements for the degree doctor scientiarum.

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SUMMARY

This thesis summarises the findings made in NFR-funded project “Capillary Pressure and Capillary Heterogeneities”. The focus has been to determine the impact on oil recovery from wettability and fractures in carbonate rocks. Secondly a new method for measuring capillary pressure has been developed. The results of this work are reported in this thesis.

The work presented in this thesis has improved the understanding of the interaction between wettability and fractures on the production mechanisms in carbonate reservoirs, in different directions. Figure 1 gives an overview of the project “Capillary Pressures and Capillary Heterogeneities”, its fundamental building blocks and the interaction between them to better understand how main conclusions in this study may be drawn;

Building block 1:
A reproducible method for altering wettability has been developed, and continuously improved throughout the study. Feed-back from the large scale block experiments have actively been used to improve the wettability alteration technique, in particular when it comes to radial and lateral wettability heterogeneity. This is further described in Paper 1 and 2.

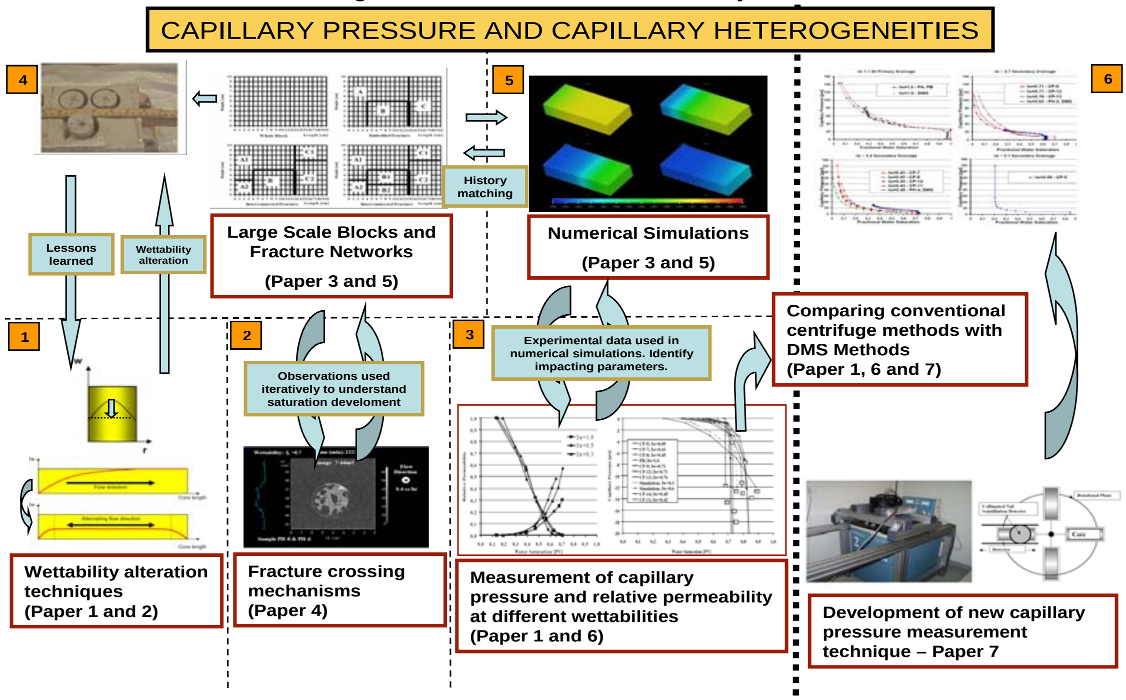
Building block 2:
The study of fracture crossing mechanisms at different wettabilities has improved the understanding of the production mechanisms in fractured chalk. The observations in the large scale block experiments have been used to understand the results of the fracture crossing experiments and vice versa. This is further described in Paper 4.

Building block 3:
Capillary pressure and relative permeability curves have been measured at different wettabilities. The capillary pressure curves in particular, have also been measured using different centrifuge methods. The experimental results have actively been used in numerical simulations. The numerical simulations in return have been used as QC for the experimental results, especially when measuring the spontaneous and forced imbibition curves. This is described in Paper 1 and 6.

Building block 4:
Large scale waterflood experiments have been performed at different wettabilities, using different fracture networks, measuring the in-situ saturation development. This has led to an improved understanding of the production mechanisms in this type of reservoirs. Further details can be seen in Paper 3 and 5.

Building block 5:
Numerical simulations have actively used the experimental data obtained from the large scale block experiments and the capillary pressure/relative permeability, and at the same time provided an improved understanding on the potential impacts of changing the parameters. It has also helped us to improve the interpretation of the results. Paper 3 and 5 treats this aspect in detail.

Fig. 1 – Focus areas for this study



Building block 6:

The outlines of a method for measuring in-situ capillary pressures at different wettabilities have been presented, and a feasibility study performed. If this method is further developed and successful, it could be possible to measure in-situ capillary pressure curves using live crude oil at reservoir conditions. This work is reported in Paper 1, 6 and 7.

The main conclusions drawn from this thesis are;

7 scientific papers are published on a broad variety of subjects, and describes in detail the experiments and research treated in this thesis. Scientific research has been performed, investigating the subjects of capillary pressure and capillary heterogeneities from different angles.

This thesis discusses the findings in this study and aims to illustrate the benefits of the results obtained for further development of other experiments, and/or even the industrial benefits in field development.

The methods for wettability alteration have developed throughout the work. From producing heterogeneous wettability alterations, the methods have improved to giving both radial and lateral uniform wettability alterations, which also remains unaltered throughout the duration of the experimental work. The alteration of wettability is dependent on initial water saturation, flow rate, aging time and crude oil composition.

Capillary pressure and relative permeability curves have been measured for core plugs at different wettabilities using conventional centrifuge methods. The trends observed are mostly consistent with theory.

The production mechanisms of strongly and moderately water wet chalk has been investigated. At strongly water wet conditions in fractured chalk; the flow is governed by capillary forces, showing strong impact from the fractures. At moderately water wet conditions, the impact of the fractures are absent, and a dispersed water front is observed during the displacement. The oil recovery is about the same, at the two wettabilities.

Fracture crossing mechanisms at the same wettability conditions have been mapped. And the observations are consistent with those of the water floods. During strongly water wet displacement, the fracture crossing is occurring once the inlet core has reached endpoint of spontaneous imbibition. At moderately water wet conditions the fracture crossing is less abrupt, and creation of wetting phase bridges is observed. The water may pass the capillary discontinuity before inlet core is at endpoint for spontaneous imbibition.

The observations of the water flood experiments have been validated using numerical simulators Eclipse and Sensor. Experimentally measured capillary pressure and relative permeability curves have been used to history match the observed production of the waterfloods. The observed variations in production mechanisms at wettability change are confirmed.

Direct measurement of saturation methods for measuring capillary pressure scanning curves have been investigated and compared to conventional centrifuge techniques. The same trends are observed for curves measured at different wettabilities, and the capillary pressure curves measured using DMS methods have also been validated in numerical simulations of type Eclipse and Sensor.

A feasibility study to develop a new method of measuring capillary pressure at various wettabilities has been performed with encouraging results. The conclusion is that the work should be further developed. The method has potential to enable capillary pressure measurements using live crude oil at reservoir conditions.

All in all, several experimental methods applicable in future SCAL synthesis have been presented. The observations are consistent and underline the production mechanisms of fractured chalk reservoirs, and will serve as inspiration in the future evaluations of tertiary oil recovery processes. An innovative approach to the measurement of capillary pressure is suggested.

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Thomas Bognø

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Part 3: Scientific Papers

Paper 1
Graue, A., **Bognø, T**., Moe, R.W., Baldwin, B.A., Spinler**,** E.A., Maloney, D., Tobola, D.P.: "Impacts of Wettability on Capillary Pressure and Relative Permeability", SCA9907, Reviewed Proc.: 1999 International Symposium of Core Analysts, Golden, Co., USA, Aug. 1-4, 1999.

Paper 2
Graue, A., Aspenes, E., **Bognø, T**., Moe, R.W., Ramsdal, J.: "Alteration of Wettability and Wettability Heterogeneity", J. Petr. Sci. & Eng. 33 (3-17), 2002.

Paper 3
Graue, A., **Bognø, T**.: "Wettability Effects on Oil Recovery Mechanisms in Fractured Reservoirs", SPE74335, December 2001 SPE Reservoir Evaluation & Engineering.

Paper 4
Graue, A., Aspenes, E., Moe, R.W., **Bognø, T**., Baldwin, B.A., Moradi, A., Tobola, D.P.: "Oil Recovery Mechanisms in Fractured Reservoirs at Various Wettabilities Visualized by Nuclear Tracer Imaging and NMR Tomography", Rev. Proc.: 22nd Annual Workshop & Symposium Collaborative Project on Enhanced Oil Recovery International Energy Agency, Sept. 9-12, Vienna, Austria, 2001.

Paper 5
Bognø, T. and Graue, A.: "Impacts of capillary pressure imbibition curves on the simulation of waterfloods in high capillary moderately-water-wet chalk", Proc.: 6th Nordic Symposium on Petrophysics, Trondheim, May 15-16, 2001.

Paper 6
Bognø, T., Graue, A., Spinler, E.A., Baldwin, B.A.: "Comparison of Capillary Pressure Measurements at Various Wettabilities Using the Direct Saturation Measurement Method and Conventional Centrifuge Techniques", reviewed proceedings, the 2001 International Symposium of Core Analysts, Edinburgh, Scotland, Sept 17-19, 2001. Submitted for publication in Transport in Porous Media.

Paper 7
Graue, A., Spinler, E.A., **Bognø, T**., Baldwin, B.A.: "A Method for Measuring In-situ Capillary Pressures at Different Wettabilities using Live Crude Oil at Reservoir Conditions", reviewed proceedings, the 2002 International Symposium of Core Analysts, Monterey, California, USA, August 2002. Submitted for publication in Journal of Petroleum Science and Engineering.

Introduction

All field development projects of today start by a thorough static and dynamic synthesis. Geophysical and geological interpretations provide a structural and sedimentological understanding, using seismic data, and all available exploration and appraisal well data. Core analysis, both conventional and special, is performed to predict petrophysical properties of the reservoir, as well as the dynamic behaviour of the field throughout a life of production. Capillary pressure and relative permeability measurements are instrumental in determination of reserves, production plateau, dimensions of processing capacities and ultimately the economy of a project.

A large part of the world's hydrocarbon reserves can be found in carbonates. Carbonate reservoirs are complex in the sense that the reservoir rock normally is brittle and easily fractured. In addition the chemistry of the reservoir rock makes the pore surfaces more prone to wettability alteration compared to for example some consolidated sandstone reservoirs. The presence of fractures and wettability variations complicates the development plan significantly and impacts the production behaviour of the field.

From this motivation a project was started at the University of Bergen, which studies the impact of wettability and fractures on oil recovery. The project was initiated in 1990 at the University of Bergen and is a collaboration with ConocoPhillips Research and Development group in Bartlesville, Oklahoma. The focus in the early phase of the project was to identify outcrop chalks resembling the chalk of the North Sea chalk reservoirs. Of the tested chalks, Rørdal chalk obtained from the Portland quarry in Ålborg was selected. Further a method for reproducible wettability alteration was studied with emphasis on the wettability conditions, moderately water wet (I_w=0.6) and nearly neutral-wet (I_w=0.3). In the next phase of the project, waterflooding larger chalk blocks utilizing a nuclear imaging technique for in-situ water measurements was initiated. The focus of these waterfloods was to investigate the interaction between gravity, capillary and viscous forces during oil recovery by water injection. Further the impact of fractures and wettability was studied.

This thesis summarises the findings made in NFR-funded project "Capillary Pressure and Capillary Heterogeneities", and originates from the same research group. The focus has been to determine the impact of wettability and fractures on multiphase flow in carbonate rocks. Secondly a new method for measuring capillary pressure has been developed. The results of this work are reported in this thesis.

Paper 1 presents the impact of wettability on capillary pressure and relative permeability. 2 different methods of capillary pressure measurement are used to derive the capillary pressure curves. In **Paper 2** the wettability alteration method is improved, reducing the internal variations of wettability in core plugs. **Paper 3** explains how oil recovery mechanisms in a fractured reservoir change from capillary dominated at strongly water wet conditions towards more viscous dominated at less water wet conditions. Further measurements on capillary heterogeneities were presented in **Paper 4**, looking in detail at fracture crossing mechanisms at various wettabilities. **Paper 5** presents the application of the obtained experimental data from capillary pressure and relative permeability measurements, and waterfloods in fractured chalk at different wettabilities, in numerical simulations. **Paper 6** compares capillary pressure curves derived from a direct measurement of saturation method and capillary pressure curves derived using conventional measurement techniques. Finally **Paper 7** describes in detail the development and preliminary testing of a method potentially capable of measuring two and three phase capillary pressures at reservoir conditions with respect to pressure and temperature, using live crude oil.

This thesis is divided into three parts. In **Part 1**, theory on capillary pressures and capillary heterogeneities, as well as their importance in field development, are presented. The experimental work carried out in this thesis, along with the results and conclusions are summarised in **Part 2**. **Part 3** contains the scientific papers.

PART 1 – CAPILLARY PRESSURE AND CAPILLARY HETEROGENEITY

1 - Capillary Pressure

1.1 Introduction

Capillary pressure is an important parameter in the study of porous media containing two or more immiscible fluids. Together with viscous and gravitational forces, the capillary force of a porous medium controls the distribution as well as the flow of the immiscible phases. The existence of capillary pressure is founded in the interfacial tension or interfacial free energy that exists between two immiscible fluids. The capillary pressure is larger the smaller radius of the capillary tube (or pore).

The capillary pressure curve is a function showing how the capillary pressure varies with fluid saturation. A porous medium has a continuous distribution of pore sizes; hence the capillary pressure curve is a continuous function of fluid saturation. A typical capillary pressure curve is shown in Figure 1.1. Here the capillary pressure is plotted as a function of water saturation. It is common to plot P_c as a function of the wetting phase. S_{wi} is called the irreducible water saturation. This is the point where the capillary pressure increases asymptotically towards infinity, or where it is impossible for the non-wetting phase to displace more of the wetting phase. This curve provides a lot of information about the porous medium in which the fluids are flowing. For instance it can tell us about pore size distribution and the wettability of the system.

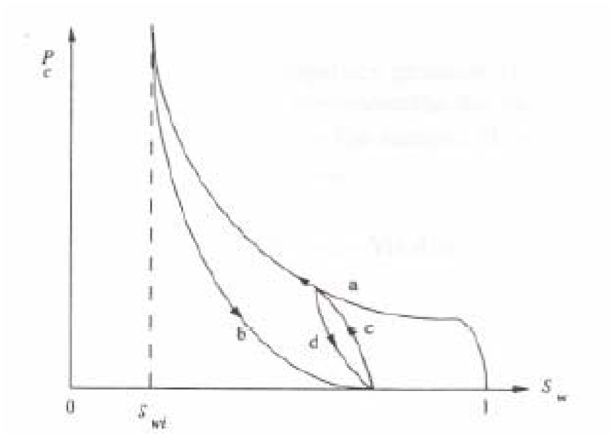


Figure 1.1 A primary drainage capillary pressure curve (a) with drainage-imbibition hysteresis loops (b,c,d). (Spor Monograph).

The difference in capillary pressure from drainage to imbibition at the same saturation is an effect of hysteresis. This capillary pressure hysteresis originates from contact angle hysteresis and also difference in capillary retention. Contact angle hysteresis will be further discussed in Chapter 2.

In a fractured reservoir the capillary forces are of greater importance, than a homogeneous, un-fractured reservoir. A fracture may be referred to as a capillary heterogeneity, an area of the reservoir where the capillary forces acts differently from matrix capillary pressure curve. In a fractured reservoir, knowledge of the capillary force interaction is integral to understand the recovery mechanisms. In a fractured reservoir the capillary forces may contribute to the displacement process during imbibition, or oppose it during a drainage process (Van Golf-Racht, 1982).

In a fractured reservoir an imbibition will occur whenever the wetting phase is filling the fractures and the non wetting phase is contained in matrix blocks. A simple case is illustrated in Figure 1.2 a). In case a) the capillary forces are the only forces imbibing water and displacing the oil. In case b) both the capillary forces and the gravitational forces have an impact on the process.

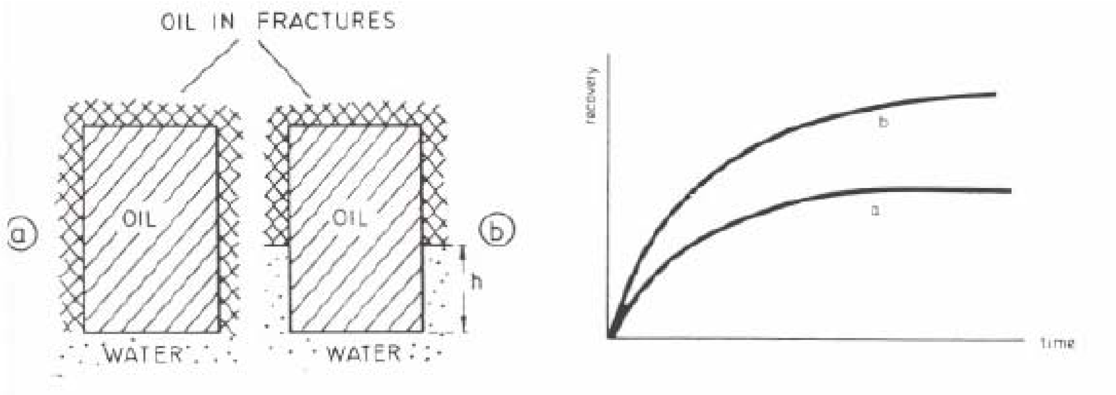


Figure 1.2 a) Case a: Displacement under capillary forces. Case b: Displacement under both capillary and gravity forces. Figure 1.2 b) Recovery vs. Time for cases a and b in Figure 1.2 a). (Van Golf Racht)

Due to density differences the water will invade the larger pores in the matrix. The capillary forces will control the smaller pores. This will affect the imbibition process in many ways, of which the most important may be that it speeds up the imbibition process in the transition zone around the water-oil contact. It has been shown that the recovery increases, and the recovery rate increases in a fractured reservoir. This is illustrated in Figure 1.2 b).

Throughout this thesis one may observe that capillary continuity within the fractures is also an important issue. There are different types of fractures, and these all act different with respect to capillary forces. An open fracture has a minimum of capillary continuity, while a closed fracture has a large degree of capillary contact (Firoozabadi & Hauge, 1989). Open fractures are more of a heterogeneity than closed fractures in the sense that they will cause more capillary end-effects and capillary hold ups than closed fractures. Closed fractures with good capillary continuity merely serve as permeability enhancers or permeability barriers.

Fracture permeability is an important issue. Both the permeability across the fracture and the permeability along the fracture may have severe impacts on fluid flow. Normally a closed fracture will serve as a permeability enhancer along the fracture, and a permeability barrier for flow across the fracture. The latter because the pore structure of the chalk may be damaged along the fracture zone and thus reduce permeability. Along the fractures fluid will flow more easily. A secondary recovery project in a fractured reservoir may consist of water injection, where the water will flow in the fracture network. This will allow a process of spontaneous imbibition of water into the matrix blocks, expelling the oil into the fracture network. The expelled oil will then be displaced by further water injection. In addition to oil production by capillary imbibition, the water injection may induce differential pressures due to differences in the water oil contact in the fracture network and each matrix block, and then density difference of the in place fluids. These differential pressures are the origin of an additional forced imbibition process.

1.2 Measurement of capillary pressure – general overview

Capillary forces are one of three major interactions governing the multiphase flow in a porous medium; hence extensive efforts are dedicated to the development of methods for measuring the size and impacts of these forces. Correct measurement of the capillary pressure curve with minimum uncertainty is essential. Four major groups of measurement techniques exist for measuring capillary pressure relationships; mercury methods, porous plate methods and centrifuge methods, often referred to as conventional centrifuge techniques, and finally direct measurement of saturation methods.

The porous plate method is an example of a static method to measure the capillary pressure curve. A sample completely filled with the wetting phase is immersed in a non-wetting phase, the sample placed on a porous plate. The porous plate is only permeable to the wetting phase, having smaller pores than the sample and the same wettability. As the pressure of the non-wetting phase is increased, smaller and smaller pores of the sample will be drained. The highest capillary pressure is determined by breakthrough of the non-wetting phase through the porous plate. Imbibition capillary pressure curve can be measured by reversing the process, reducing the pressure of the non wetting phase and letting water imbibe back into the sample. See Figure 1.3.

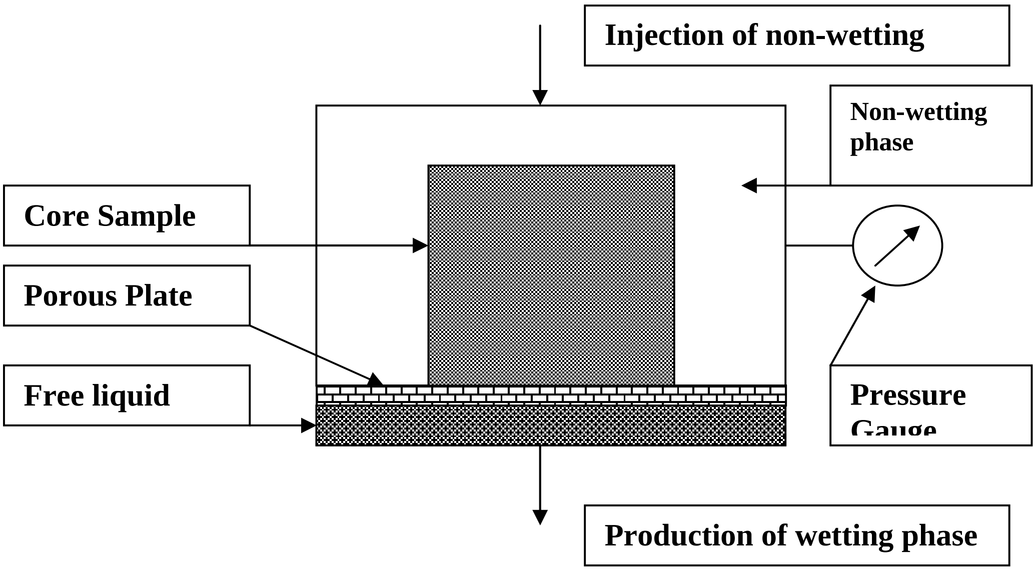


Figure 1.3 The porous plate method – conceptual sketch.

The centrifuge method is a dynamic method to obtain capillary pressure curve. To obtain drainage curves samples containing 100% wetting phase is immersed in non-wetting phase and spun in a centrifuge. As the angular velocity of the centrifuge increases, the higher density of the wetting phase to the non-wetting phase makes the wetting phase leave the sample at its outer radius as it is simultaneously replaced with the non-wetting phase. At each different angular velocity a different equilibrium will form. We are able to read the production from the centrifuge and calculate the saturation.

This saturation is an average saturation derived from material balance, which does not take into account internal variations over the core sample. The centrifuge fluid production data needs to be transformed into capillary pressure curves using corrective models that permits us to take into account possible radial and lateral saturation variations over the cores, as well as impacts from gravity (at low rotational speeds) or different centrifuge geometries. This inverse problem is known as the centrifuge problem and is thoroughly described in the two SCA surveys from 1993 and 1997 by Forbes.

The centrifuge problem may be omitted by measuring capillary pressure curves using **direct measurement of saturation methods** which are not based on back-calculation of the average saturation. When using the conventional centrifuge techniques, the capillary pressure curves are actually calculated using a mathematical model using the average saturation as input parameter. However it is possible to directly measure the saturation distribution within a core plug, and thus measure the capillary pressure curve. Different variations of this type of measurement are described in detail in the enclosed scientific **papers 6 and 7**.

1.3 Literature Survey

Ever since the centrifuge technique was first introduced by Hassler and Brunner in 1945 and Slobod (1951), this technique has been evolving. It still is. Recent developments for the two main steps of capillary pressure measurement; 1) measurement of the centrifuge fluid production data and 2) transformation of these data into capillary pressure curves – have been addressed by the Society of Core Analysts through two surveys treating each respective step. The main conclusions from these surveys were;

- The main source of inaccuracy in drainage capillary pressure curve determination is related to the interpretation of the production data.
- The inaccuracy depends on centrifuge geometry and the resulting contribution of centrifugal and radial effects, and finally the method used for solving the centrifuge problem.
- Errors introduce through the inversion process may not be remedied by increasing the experimental detail of the centrifuge experiment.

Sarwaruddin et al. (2000) compare different methods for measuring capillary pressure. While conventional centrifuge techniques may produce saturation errors in the order of 10%, and porous plate and gravity drainage methods are more accurate but too time consuming, direct methods stands out as reliable and efficient. Various direct methods are discussed.

Baldwin et al. (1991) use NMR image technique in order to determine saturation profile for the centrifuged plugs in-situ. This method is quick and directly obtains saturation images at several sections of the cores and provides an accurate capillary pressure curve, provided that radial and gravity effect may be neglected.

Chen et al. (1995) showed that gravity effects are negligible if the centrifuge speed is higher than 500 rpm. The radial effects will be important, increasing with increasing centrifuge speed. Sarwaruddin et al. (2000) propose a simple approach to remedy this.

Fleury et al. (1999) propose a method for measuring the positive part of the capillary pressure curve using the centrifuge technique, by reducing the centrifuge speed and at the same time providing a free water level. Water imbibes as the capillary pressure is reduced and the positive part of the capillary pressure curve may be measured. This proposed method potentially measures drainage, spontaneous and forced imbibition without stopping the centrifuge.

Fleury et al. (2000) propose a method for converting transient saturation curves measured during multi-speed centrifuge experiments to obtain an accurate estimation of the equilibrium saturation.

Fernø et al. (2007b) present capillary pressure measurements also using the multi-rate centrifuge technique, on water-wet and oil-wet carbonate plugs. Capillary equilibrium is found to be a function of wettability and absolute permeability. Spinning time could vary from 5 days to over a month for certain rotational speeds. The results were validated using a commercially available core analysis simulator.

Chen et al. (2006) present a single-shot method to determine the capillary pressure curve, using a single rotational speed, and a one-dimensional Centric Scan SPRITE MRI imaging technique. SPRITE is abbreviation for single-point ramped imaging with T1 enhancement.

2 - Capillary Heterogeneities

2.1 Introduction

Capillary heterogeneities have a huge impact on all aspects of field developments. Wettability and fractures are two main types of capillary heterogeneities, which are important in carbonate reservoirs. Wettability may vary from the water oil contact to top reservoir dependent on water saturation, or for instanced from one formation to another due to differences in crude composition or mineralogy. These variations of wettability throughout a reservoir induce variations in capillary forces, and could be perceived as a capillary heterogeneity. Fractures will, depending on the degree of capillary contact across and along a fracture, impose capillary discontinuities impacting multiphase flow in porous media.

2.2 Wettability

Wettability is defined as "the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids" (Anderson, W.G., 1986a). This property is important in all types of core analysis, including capillary pressure, relative permeability, waterflood behavior, electrical properties, and simulated tertiary recovery. It does not only apply on a laboratory scale, but also on a reservoir scale.

The literature has defined different types of wettability. In a brine/oil/rock system the wettability can range from strongly water wet, through neutral wet, to strongly oil wet. The two extremities of strongly water wet and strongly oil wet are probably the two most studied cases, in spite of the fact that many reservoirs are in the intermediate wet region or even mixed wet or fractional wet.

Mixed wet reservoirs (Salathiel, 1973) originate from the wettability's tendency to control fluid distribution within a reservoir or core. It is generally accepted that water is always the initial fluid present in the rock. Hence a reservoir will initially be strongly water wet. When oil starts to migrate into the reservoir it is possible that the wettability will change from strongly water wet towards neutral wet, or even strongly oil wet in the wider pores, while the narrow pores remain strongly water wet.

Fractional wettability is also called heterogeneous wettability. This wettability originates from heterogeneities in the rock surface of the reservoir. The surface chemistry and adsorption properties may vary in the reservoir, due to different mineral composition. Because of this a reservoir may be strongly water wet in one area of the reservoir and strongly oil wet in another. This concept was introduced by Brown and Fatt in 1956.

Wettability alteration is a complex process. Many factors influence the process; amongst them the most important ones are composition of crude oil, pore roughness, brine chemistry, water saturation, surface mineralogy and distribution of fluids (Anderson, W.G. 1986a, b, Cuiec, L. 1987 and Buckley, J. 1996).

Alteration of wettability by aging – i.e. adsorption of crude oil components to the rock surface - is often used in the industry. Rock, brine and crude interactions have been studied by Buckley 1997, 1998, and conclusions are that the process is dependent on time, temperature, water saturation, acid/base number and composition of crude oil, and finally the rock surface and water chemistry. Numerous publications on wettability alteration by aging have been issued; Morrow et al. 1994, Graue et al. 1996, Jadhunandan and Morrow 1995, Zhou et al. 2000. The research group at the University of Bergen (Graue et al. 1996) have reported on reproducible wettability alteration techniques on low permeable outcrop chalk. Zhou et al. 2000 reported on wettability alteration of Berea sandstone using Prudhoe Bay crude oil and synthetic formation brine.

The crude oils migrating into the reservoirs contained compounds which were interfacial active. Buckley (Sept 1996/1998) described several mechanisms where organic compounds interact with the mineral surface of the rock. These interactions include polar, acid/base and ion-binding interactions and can be described as 1) Direct adsorption from the oil phase, 2) Adsorption through the water film, 3) Deposition of an insoluble monolayer formed at the oil/brine/rock/ interface and 4) precipitation of oil-wet solids.

The acid/base interactions are most important when water is present, and will be strongly dependent on pH. Buckley and Wang 2002 reported that the acid-to-base ratio as well as the acid and base number is important to properly describe the wetting behaviour and the efficiency of wettability alteration by acid/bas interactions. Furthermore Zang and Austad 1995 reported that wettability change in carbonates are governed by acid number of the crude oil used, in which decreasing acid number yields more water-wet conditions.

The methods most used to measure wettability in core analysis are contact angle measurement, the Amott method and the United States Bureau of Mines method (USBM-method).

Contact Angle Measurement may be the most accurate way to measure wettability when using artificial porous medium and pure fluids. That is because there is little or no chance that compounds from the oil will alter the wettability when present. It is also a good method to use when examining effects of temperature, brine chemistry and pressure on wettability.

The Amott method is based on the fact that the wetting fluid will spontaneously imbibe into a core, displacing the non-wetting phase inside the core. Actually the method is a combination of a series of flooding processes; drainage, spontaneous imbibition, and forced imbibition. For water wet cores the procedure would be as follows with respect to Figure 2.1:

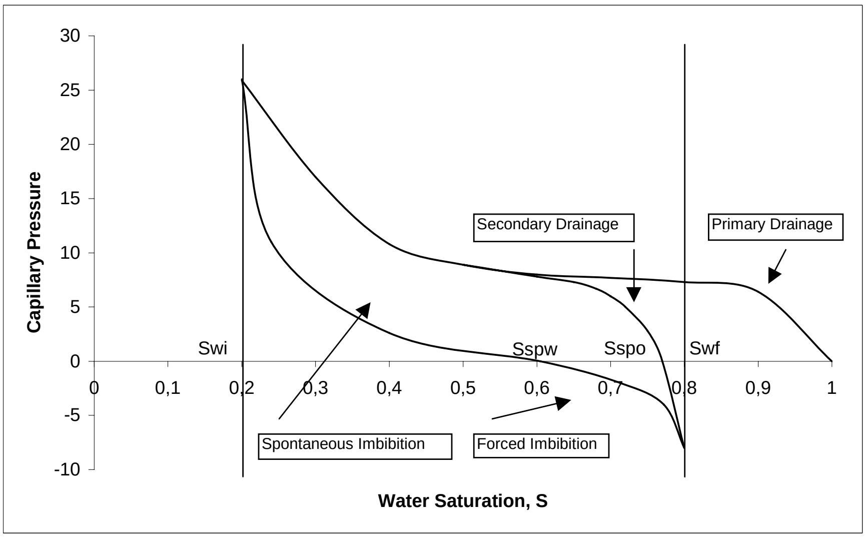


Figure 2.1 Illustration of how changes in saturation and changes in capillary pressure are used to determine the Amott Index.

Firstly a residual water saturation (S_{wi}) would be established through an oilflood. Then the core would be immersed in water for spontaneous imbibition. Measuring the oil production, the new water saturation (S_{spw}) can be established. The last saturation point needed, after forced imbibition, will be the residual oil saturation (S_{wf}) or highest water saturation possible. After this process it can be necessary to check if the core will imbibe oil spontaneously. Hence the core is immersed in oil, and any eventual water production will be measured (S_{spo}). With these saturation points available it is possible to calculate the relative displacement index (RDI) by first calculating:

$$I_w = \frac{S_{spw} - S_{wi}}{S_{wf} - S_{wi}} \tag{2}$$

and

$$I_o = \frac{S_{wf} - S_{spo}}{S_{wf} - S_{wi}} \tag{3}$$

Then the Amott wettability index can be calculated by:

$$RDI = I_w - I_o \tag{4}$$

For most water wet samples S_{wf} equals S_{spo}. Thus I_o will be zero and I_w will alone indicate the wettability of the core. The Amott index is the ratio of water produced during spontaneous imbibition and the total amount of mobile fluid. An advantage of this test is that it is easy, and not very time consuming. It is also sensitive for mixed and fractional wetted cores due to the fact that it considers both spontaneous displacement of water and oil. A disadvantage is that it is insensitive around neutral wettabilities.

Johannesen et al. (2006) proposed a method for characterizing wettability using NMR imaging (T2 relaxation time). A consistent shift toward slower relaxation times for the water phase was observed at increasing water saturations. For oil during spontaneous imbibition, as a function of increasing water saturation, a shift towards faster relaxation was observed at strongly water-wet conditions. At neutral wet conditions, the inverse trend was observed – a change towards slower relaxation times.

2.3 Literature Survey

From 1990 until today the concept of wettability, its impact on oil recovery, and the understanding of alteration mechanisms, have had significant attention in the oil industry. Water injection has become the most common secondary recovery method used, and as development projects become more and more complex also in terms of reservoir description, the industry has been forced to review the fundamentals of reservoir engineering, herein capillary pressure and capillary heterogeneities in order to sanction economic projects with a robust reserves base. Numerous publications report on the findings;

Changes in wettability induce changes in capillary pressure with respect to rate and recovery. This has been reported in numerous publications by Torsater 1984, Jadhunandan and Morrow 1991, Cuiec et al. 1994, Graue et al. 1996, Tang et al. 1996 and Zhou et al. 1995 & 2000. Main observations include;

- Rate of spontaneous imbibition dependent on wettability.
- Induction time dependent on wettability.
- Permeability, matrix surface, heterogeneity, fluid composition and interfacial tension will also affect the capillary imbibition.

A key parameter, also strongly dependent on wettability, is the residual oil saturation after waterflooding. Literature generally reports that the residual oil saturation is a function of wettability, oil and water viscosity, formation water properties (salinity), pore network, and permeability.

Several authors have reported a decrease of residual water saturation with decreasing water wet conditions. See for instance Jadhunandan et al. (1995). Johannesen et al. (2007a) presented a systematic approach to investigate the oil recovery in chalk as a function of wettability. On 75 core plugs, ranging from near neutral wet to strongly water wet, oil recovery after waterflooding exhibited a maximum at about Iw = 0.4, independent of the initial water saturation. Johannesen et al. (2007b,c) also presented a systematic investigation of residual water saturations as a function of applied pressures, or capillary numbers. Minimum residual oil saturation was observed for Iw = 0.4, and it was evident that the residual oil saturation decreased with increase capillary number – i.e. increased viscous component. See Figure 2.3.

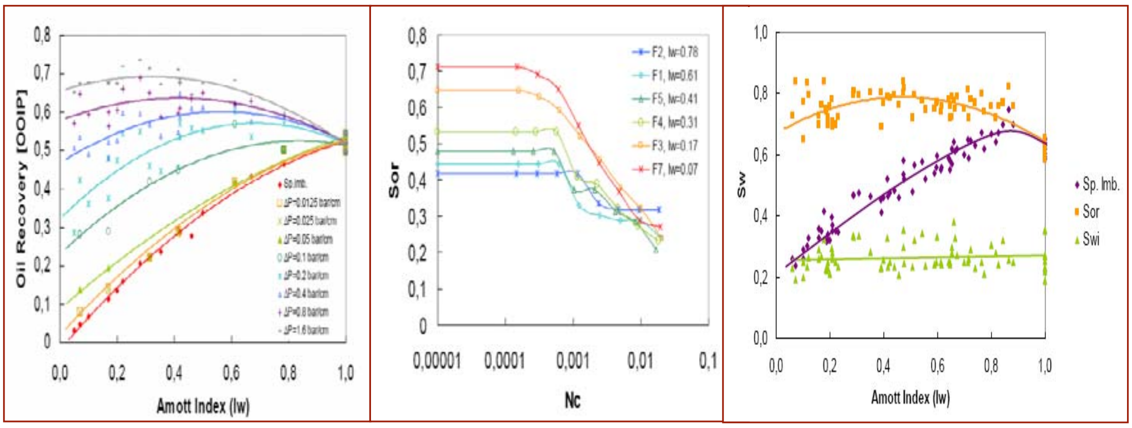


Figure 2.3 From Johannesen et al (2007). Left: Water saturations after forced imbibition as a function of wettability at different capillary numbers. Swi = 22 +- 2%. Centre: Residual oil saturation versus Capillary number at various wettabilities. Right: Sw as a function of wettability for 75 chalk plugs, initial, spontaneous imbibition and finally force imbibition endpoints.

2.4 Fractures

While wettability is a capillary heterogeneity that is related to fluid and rock properties along with the petrophysical and chemical properties of the reservoir rocks, fractures in all its shapes and size are generated at an entirely different scale. From movement of tectonic plates, to extensional or contractual basins, then further to local salt diapirism and structural faulting, different types of fractures are generated. Great sealing faults with major throw or microfractures – all are potential capillary heterogeneities affecting fluid flow in the reservoir in its own way.

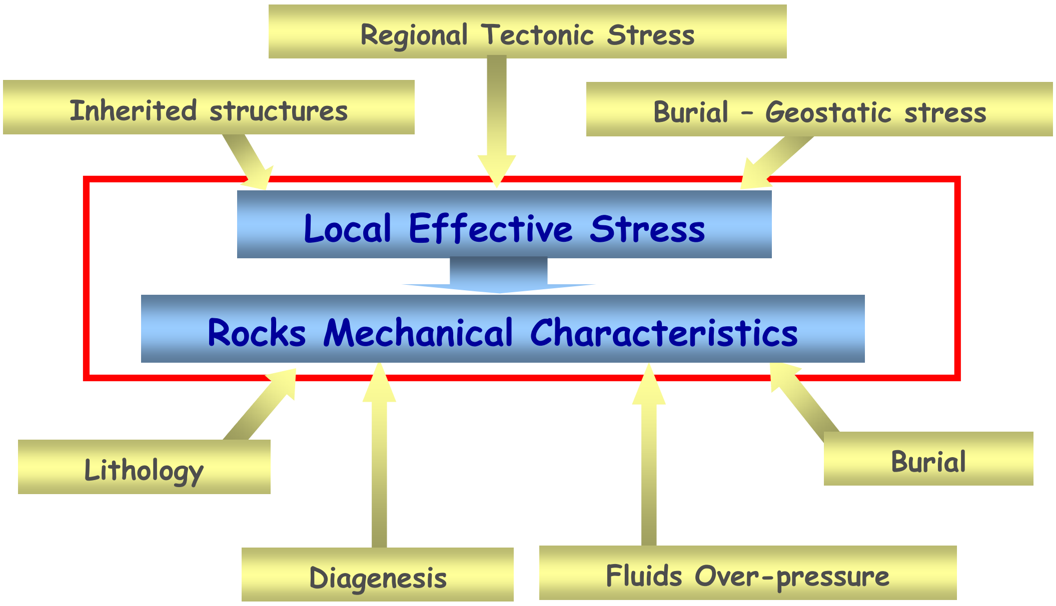
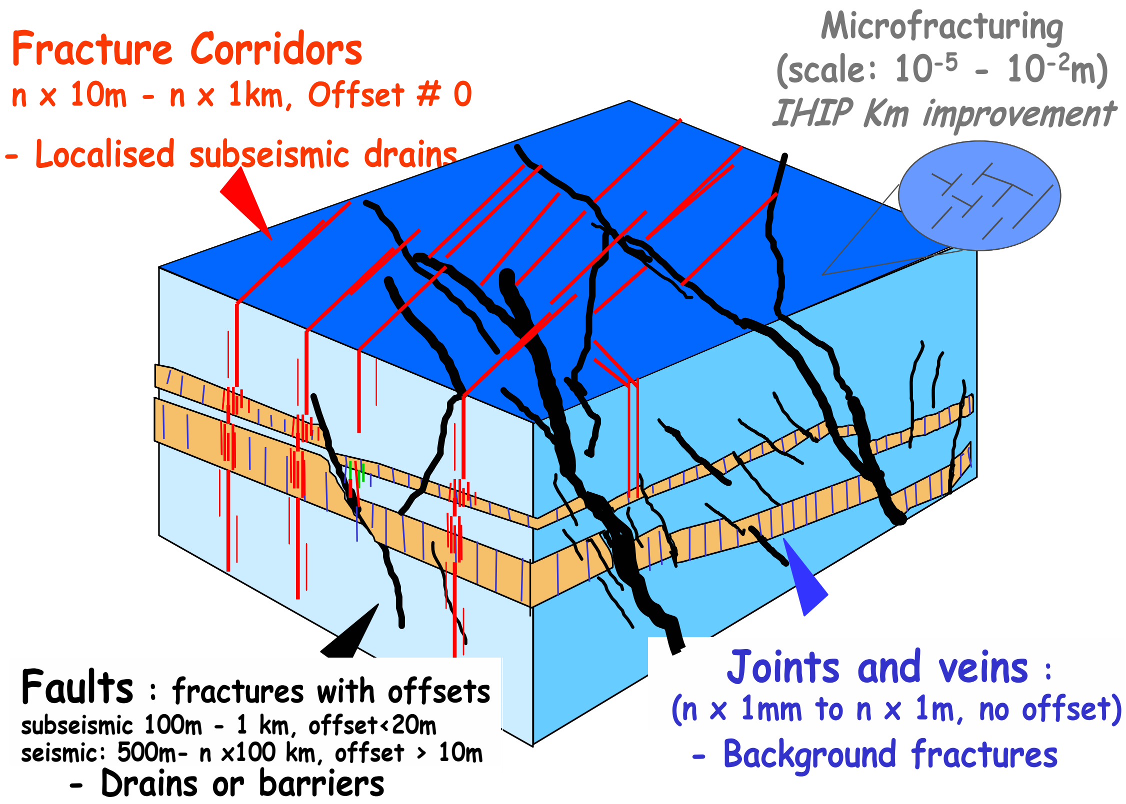


Figure 2.4 Factor that may impact the fracture network in a reservoir.

To estimate the size and type of fracture network in a reservoir it is necessary to take into account the whole history of a basin. See Figures 2.4 and 2.5. Sedimentology may for instance provide a link between fracture and lithology. Layer thickness of a depositional unit may indicate limitations on matrix block height, which again may indicate what type gravitational pressure gradients are available to sweep oil trapped by lower spontaneous imbibition endpoints in facies with lower permeability. The field geology and tectonic history may give information on potential major confining faults for accumulations, or indicate zones of different fracture density. The object is of course to estimate what is actually contributing to flow, also taking into account potential sementation, filling of breaches, and also anhydrite, calcite and shales.

Different scales of fracturing and related mechanisms



Each fracture type may or may not have an impact on the dynamic behaviour of the reservoir for a given development plan

Scales	Horizontal	Vertical	Throw
Seismic fault	500 m - 10 km	100 m - 1 km	10 m - 500 m
Sub-seismic fault	100 m - 1 km	50 m - 500 m	# 0 - 20 m
Fracture corridor	10 m - 1 km	10 m - 100 m	# 0 m
«Fracture-Joint»	1 cm - 10 m	1 cm - 10 m	# 0 m
Micro-fracture	1 mm - 1 cm	1 mm - 1 cm	0

Figure 2.5 Fractures at different scales.

The Nelson fracture criteria proposes a classification of fractured reservoirs in general, and from this classification the literature has performed synthetic studies to see what recovery factors we may expect from fractures reservoirs;

Nelson in 1999 proposed a classification of reservoir taking into account the 2 main parameters impacting the reservoir quality: porosity and permeability. He classifies reservoir where porosity and permeability are in matrix or fractures.

Type III is typical dual porosity or fractured reservoir behaviour and is linked in most of cases with existence of diffuse fracturing. See Figure 2.6;

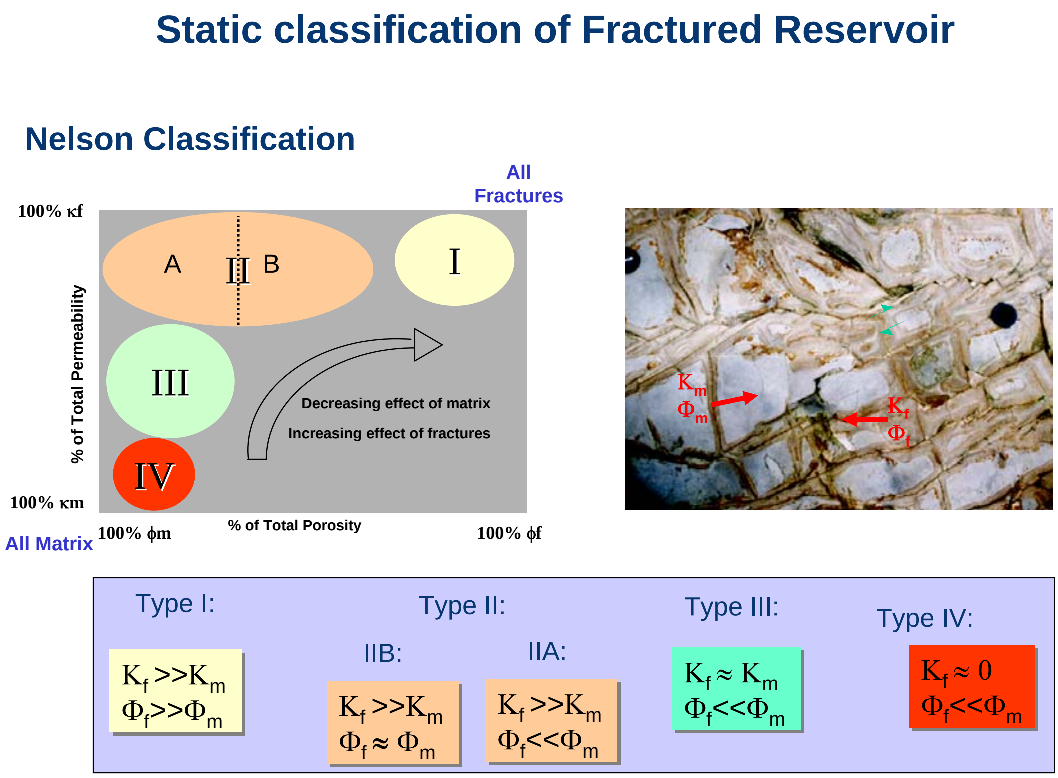


Figure 2.6 The Nelson criteria for classification of fractures.

A benchmarking study have been performed, departing from the Nelson criteria to investigate various fractured reservoir field developments and their associated recovery factors. The results showed a great spread in recovery factors – see Figure 2.7;

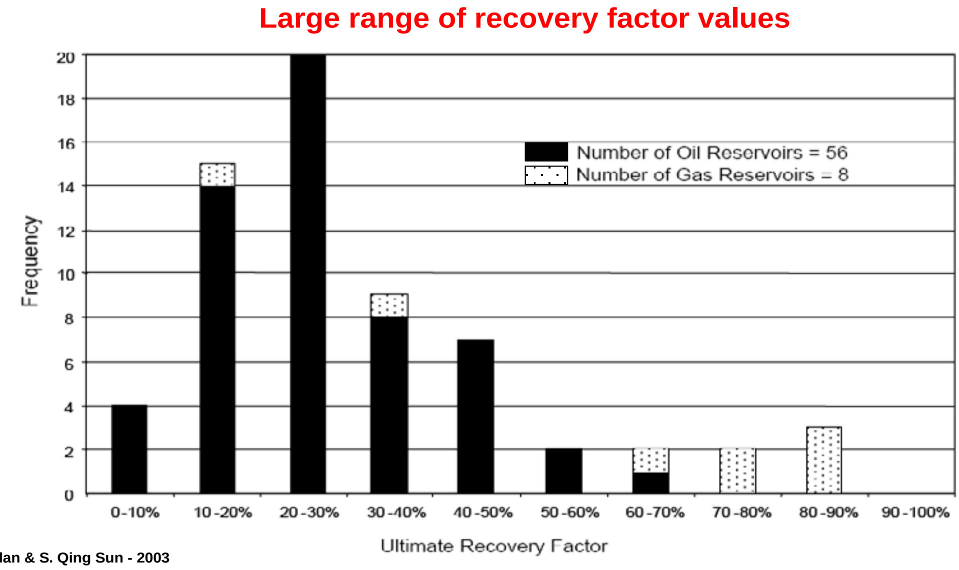


Figure 2.7 Spread of recovery factors in fractured reservoirs. Allan and Sun 2003.

It was concluded that fracturing could either favour recovery by enhancing productivity or stop recovery because of early water breakthrough due to flows bypassing the matrix. Very low recoveries were observed when fracturing occurred in combination with poor hydrocarbon properties, poor matrix properties or badly designed development schemes. The conclusion was that fractures alone are usually not responsible for low oil recoveries. A good field characterisation usually gave a good and efficient development scheme, understanding all possible recovery mechanisms. Two examples were are quite illustrative – Figure 2.8 and 2.9;

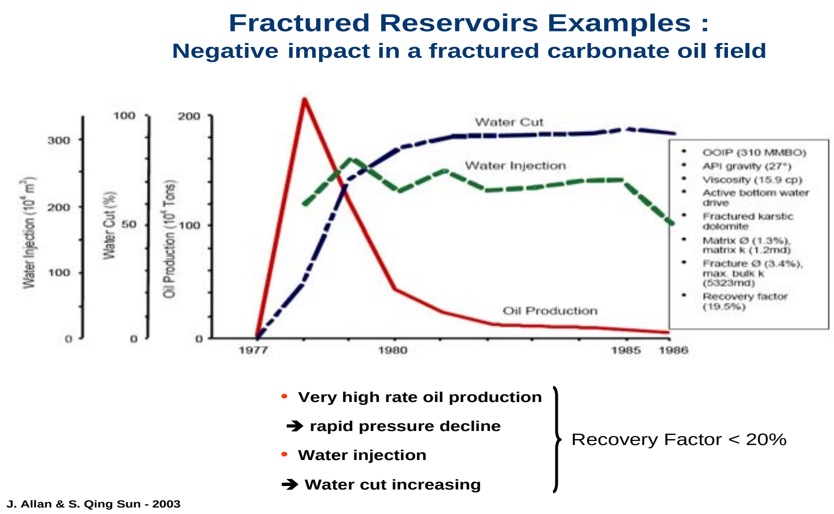


Figure 2.8 Negative impact in a fractured carbonate reservoir. Allan and Sun 2003.

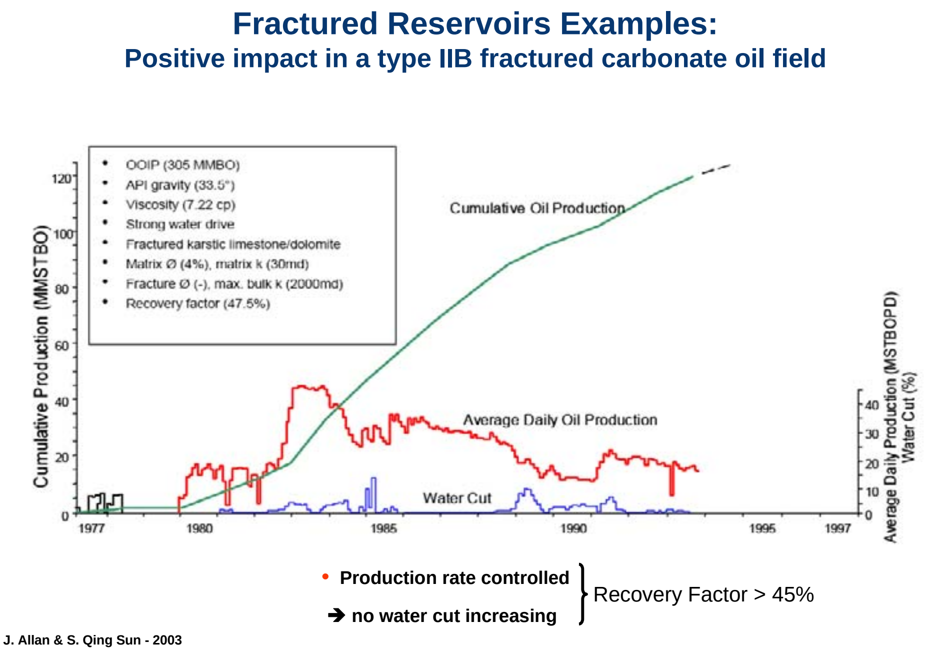


Figure 2.9 Positive impact in a fractured carbonate reservoir. Allan and Sun 2003.

The observation is the same in field development, as in a laboratory experiment; recovery mechanisms must be fully understood, and the development plan/execution plan must be designed for the desired results.

In the Greater Ekofisk Area in the southern North Sea there is a high concentration of oil baring accumulation situated in fractured chalk with strong wettability variations. The reservoir rock was deposited in early Paleocene and late Cretaceous age. The porosity is usually around 40%, and permeability ranges from 1-10 mD in the matrix, while the fracture network may carry permeabilities 10 to 100 times that of the matrix.

Different types of fractures have different type of impact on fluid flow in a fractured reservoir. Open fractures have high porosity and permeability compared to matrix. Nevertheless is the volume of the fracture network limited, and it will serve as a highway of injection phase delivery, and production phase removal, providing injector to producer communication. Closed fractures connect matrix blocks, generating important forced imbibition potential due to gravitational forces. Fluid contacts may be different in fracture and matrix.
A lot of important literature has treated the various production mechanisms in fractured reservoirs. Van Golf Racht (1982) discussed the impact of gravitational forces. Saidi et al. (1979), Horie et al. (1990) and Pratap et al. (1997) have all treated the issue of capillary contact between matrix blocks. Also Uleberg (2004) provides interesting insights to the simulation in gravity drainage experiments. See Figure 2.10.

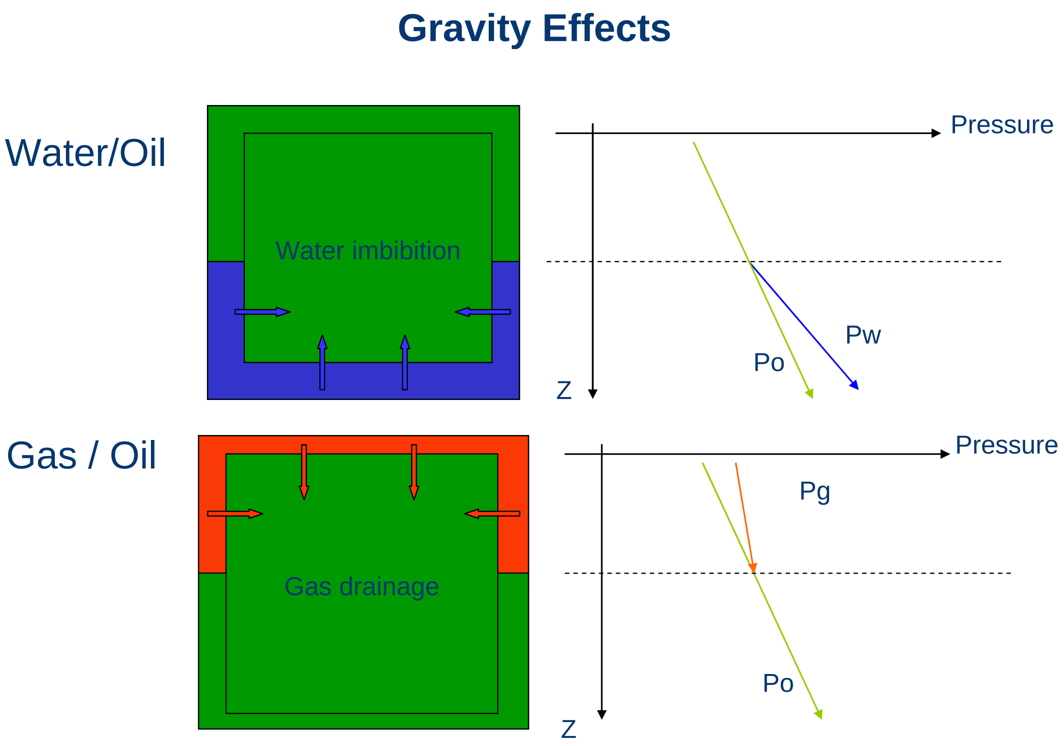


Figure 2.10 The concept of gravity drainage.

2.5 Capillary heterogeneities in field developments.

Return on average capital employed – an ever returning financial parameter in the petroleum industry: what is the benefit of investing money in SCAL studies? This discussion takes place for every field development investment decision around the world. The same challenge mounts for this study – how may the experiments performed in this thesis be valid and applicable in field development?

An average field development project goes through typical phases;

- Discovery during exploration phase.
- Appraisal phase – increase developable reserves.
- Pre-project phase – subsurface development plan.
- Basic Engineering – sub sea/onshore development plan.
- Project Execution and field development.
- Field production at plateau production rate.
- Field production after plateau production rate.

As the subsurface development plan is generated in the pre-project phase, most studies are carried out during and after the appraisal phase. Fluid PVT Studies and SCAL studies are normally carried out here. Basic pressure sampling and well testing is also included in this phase. Seismic interpretation, depositional models, petrophysical interpretation of logs and facies modeling will also be part of the static and dynamic synthesis performed at this point.

The following Figure from Bouchard and Fox shows the estimated NPV impact from certain parameters relevant to the development of fractured reservoirs – Figure 2.11;

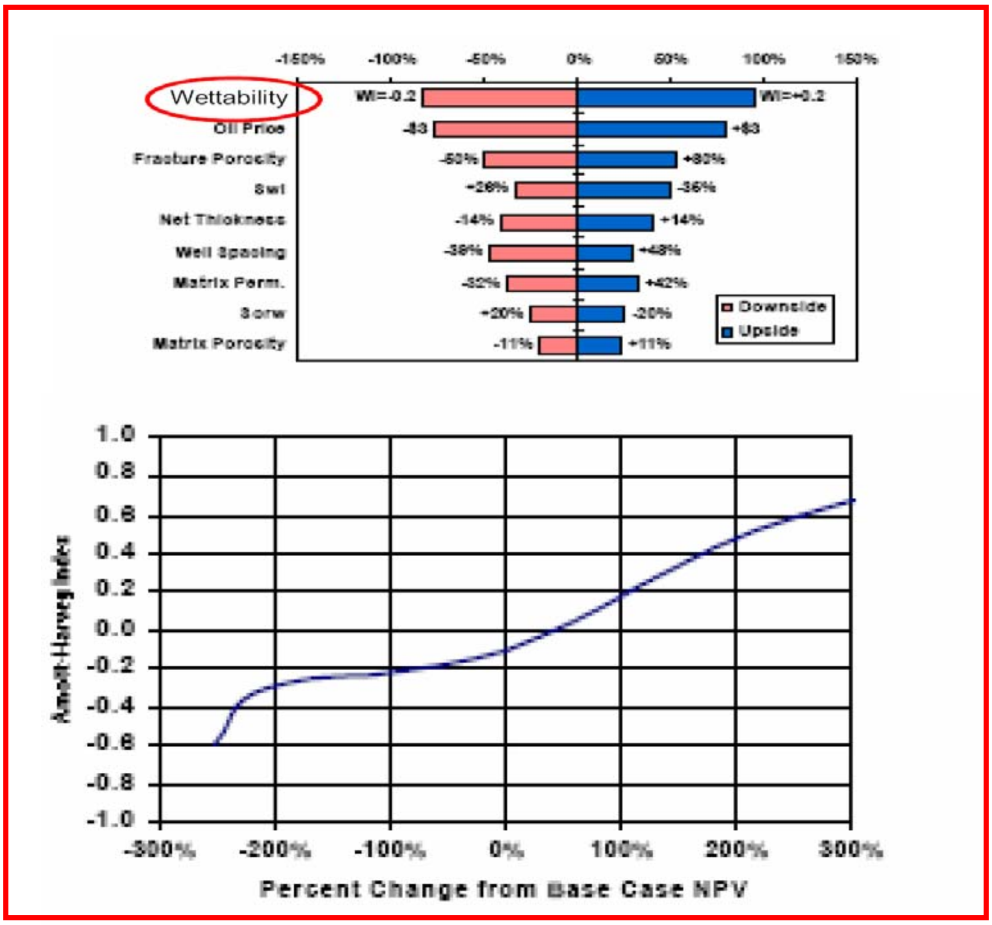


Figure 2.11 Net Present Value Impacts in field developments (Bouchard and Fox).

Well spacing and well design are dependent on the mapping of the capillary heterogeneities. Frac-procedures for both producer and injector have to be carefully considered in conjunction with this information.

The wettability, along with reservoir properties will decide the capillary pressure in every different facies of the reservoir. Channel or levee deposits, or turbidites – the capillary pressure will vary, and initial water saturation with it. In a traditional downdip up dip water injection scheme this may cause premature water breakthrough if the capillary heterogeneities are not properly mapped.

Relative permeability controls each phase's flow relative to other. Given it's dependence on wettability, and also the potential shifts due to fractures, this property needs to be carefully mapped in order to predict breakthrough times, water cut development – piston like displacement or dispersed front is dependent on interfacial tension – and ultimately is will impact the liquid treatment capacity needed on the receiving installation. Furthermore – as environmental requirements become increasingly more important – produced water re-injection is dependant on the delivery of produced water at sufficient rates, and in the same time discharge to sea (if offshore) may be a problem if water production is higher than the injection potential.

Tie in of near-by exploration resources, and potential enhanced oil recovery projects will be important to fill the design process capacities.

Throughout field life, knowledge of the reservoir will increase, and predictive history matched reservoir models can be used for estimating production profiles. However – once an enhanced oil recovery project – type surfactant, polymer or even microbial enhanced oil recovery – is to be evaluated, SCAL studies all of a sudden becomes very important again. The EOR-method, seen in context of the already existing capillary heterogeneities, needs to carefully take into account a field life of data acquisition, to optimally design and execute a successful project.

PART 2 – RESULTS AND CONCLUSIONS

3 – Methodology

3.1 Imaging techniques

Nuclear Tracer Imaging

In a standard waterflooding experiment the data derivable is production profiles, pressure data and the average saturation. However this may not always be sufficient, as for instance, when studying capillary heterogeneities, there will be a requirement of in-situ saturation data to determine the fluid distribution inside the core. This study deals with capillary heterogeneities from fractures; hence in-situ saturation measurement is a prerequisite.

Techniques providing these data may be X-ray tomography, NMR tomography or microwave attenuation. Graue (1985 and 1986), Graue et al. (1988) and Lien et al. (1988) have further developed a nuclear imaging technique from Bailey et al., measuring intensity of γ-radiation. Most of the experimental results presented in this thesis have been obtained using this nuclear imaging technique. With this technique we can visualize the impact of both fractures and wettability when waterflooding various samples of porous media.

The laboratory at the University of Bergen is equipped with a 2 dimensional rig for in-situ saturation measurements. The 2-D rig is mounted vertically on the wall, and can move in both horizontal and vertical direction - Figure 3.1. This makes it possible to make in-situ saturation measurements of large blocks of porous media. The instrumentation of the rigs is thoroughly explained in Lien et al. (1988) and Viksund (1994).

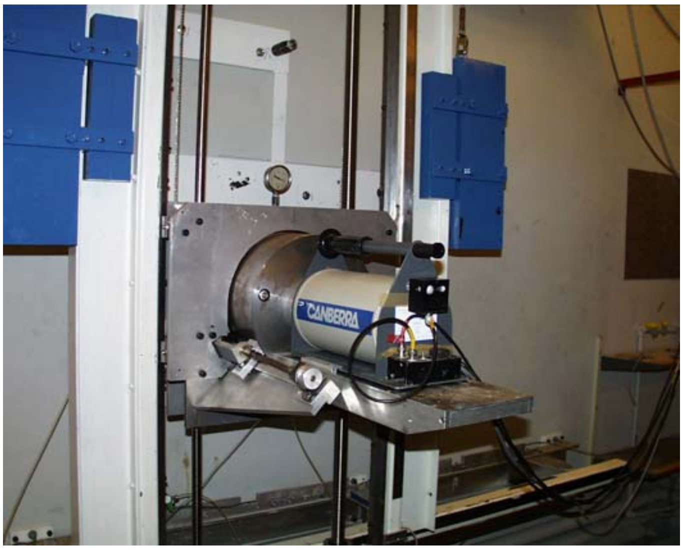


Figure 3.1 Vertical rig for 2-D in-situ saturation measurement.

With fixed collimator opening and distance from collimator to the imaging chamber, the saturation of the marked phase will be proportional to the number of disintegrations registered by the detector. The water saturation is calculated by the formula:

$$S_w = \frac{D - B}{D100\% - B} \tag{12}$$

where D is disintegrations at current saturation, B is disintegration from background radiation, and D100% is disintegrations at 100% water saturation. The uncertainty of this statistical process is given by:

$$F = \frac{\sqrt{D}}{D} * 100 \tag{13}$$

where D is disintegrations and F is the uncertainty in percent. From this we see that the uncertainty is reduced when we increase the number of disintegrations. One way to do this is to increase the counting time at each point. However the counting time is also limited by the injection rate. The front of water must not move faster than the width of the collimator during the counting time.

Fracture crossing imaging using MRI

For the fracture crossing experiments, Magnetic Resonance Imaging has been used, because of the high spatial resolution needed (0.1 mm). The Philips Research Centre provided the necessary equipment to carry out these experiments. A detailed description of the basics of nuclear magnetic resonance, the applications of NMR spectroscopy and the fracture crossing experiments may be found in Aspenes (2006).

3.2 Rock and fluid characteristics

Reservoir chalk material is very expensive to obtain. Thus in order to do extensive core analyses it is necessary to find analogues from outcrops which posses many of the characteristics found in the reservoir rock. Preferably the outcrop is also deposited at the same point in geological time.

At the University of Bergen a project was initiated in 1995, where many different outcrop chalks where examined in order to obtain an analogue to the Ekofisk field reservoir rock (Lie, 1995). Among these Dania and Portland Chalk from Denmark were examined, and found to be good fits.

In this thesis Portland Chalk from the Portland quarry near Ålborg, Denmark, has been used to represent the Ekofisk Field reservoir rock. The Portland chalk is of Maastrichtian age and consists of coccolith deposits. It contains 99% calcite and 1% quartz (Ekdale and Bromley, 1983). The rock has brine permeabilities of 1-10 mD and porosities in the order of 40-50%, which is a good fit to the Ekofisk Field reservoir rock. An explanation to this may be that in the period from Permian to Cretaceous age, Denmark was part of the North European sedimentary basin. Although Denmark was in the more shallow part of the basin the pelagic material deposited is not entirely unlike the material deposited in the Ekofisk Field. Furthermore salt intrusions, and in addition a regional stress field, led to fracturing of the outcrop.

Fluid properties are summarized in table 2, paper 2. The brine used is synthetic brine containing distilled water, 5 wt.% NaCl and 3.8 wt.% CaCl. 0.01 wt.% of sodium azide is added to prevent bacterial growth. The CaCl was added to stabilise the rock surface of the chalk, and to prevent dissolution during the experiments. Viscosity of the brine is 1.09 cP at 20°C, with a density of 1.05 g/cm3.

The crude oil used for aging experiments is a North Sea stock tank crude oil with density 0.849 g/cm3, and viscosities ranging from 14.3 cP at 20°C to 2.7 cP at 90°C. A simple analysis of the crude oil has shown that it consists of components:

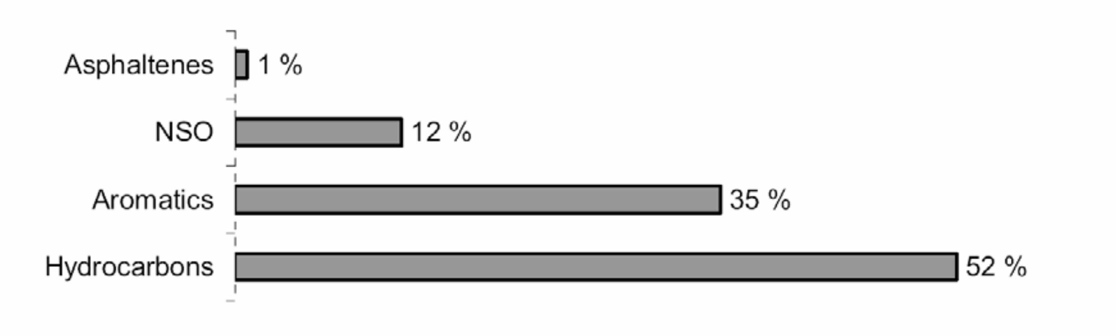


Figure 3.2 Crude oil composition (Aspenes 2006).

After aging, the crude oil was usually replaced by decalin, and then n-decane, with density and viscosity of 0.73 g/cm3 and 0.92 cP respectively.

3.3 Core preparation

Details on the core preparations can be found in paper 1 and 2. To summarize an overview may found below;

- Core plugs and core blocks were dried at 60°C for at least 3 days.
- Using a vacuum system, the cores were then saturated with brine.
- Cores were then stored in brine for at least 5 days to reach ionic equilibrium.
- Porosity was measured by weight measurement, assuming 100% saturation by water.
- Absolute permeability was measured.
- Core material would then either proceed to immediate drainage by n-decane or an aging process requiring drainage by crude oil at 90°C.

Porosity versus permeability for the 45 core plugs used in experiments in Paper 1 and 2 is plotted in a cross plot below. See Figure 3.3. The plot shows that the core material, before the subject to drainage by crude oil, is very homogeneous with small variations in porosity and permeability.

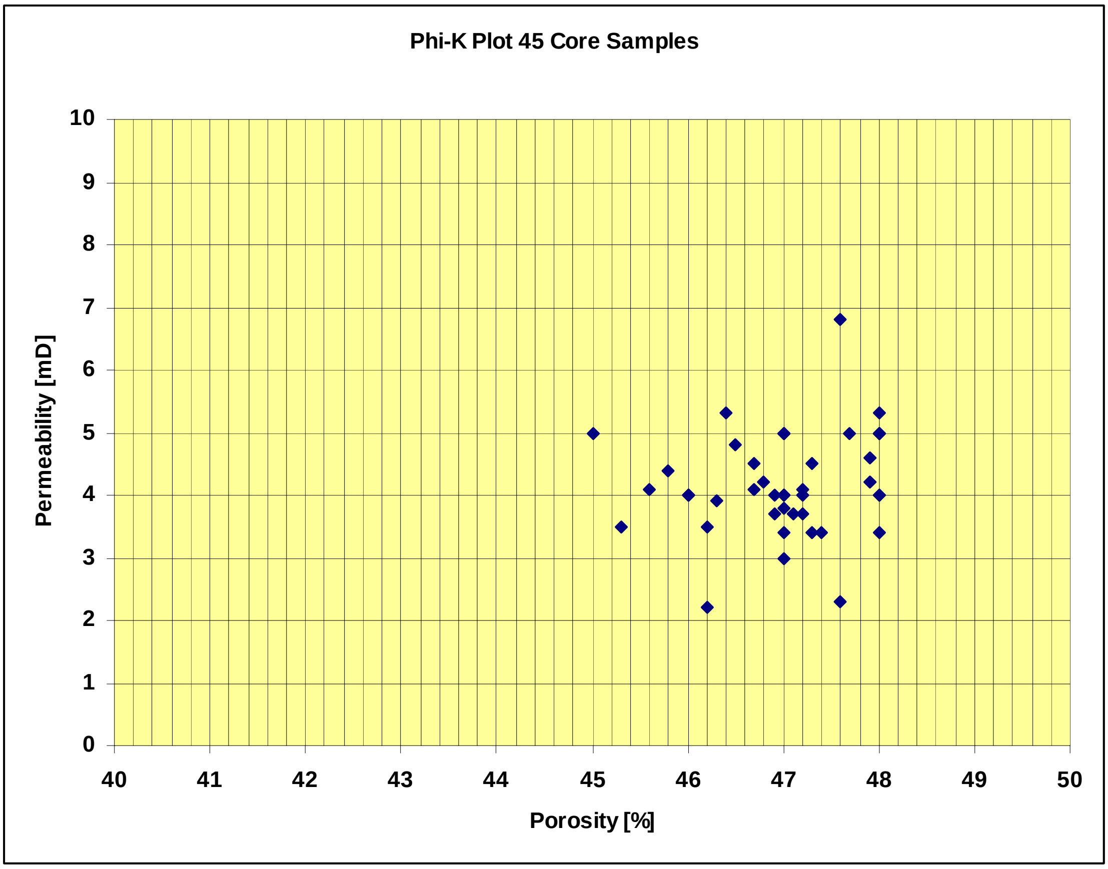


Figure 3.3 Phi-K crossplot of Portland chalk plugs.

3.4 Wettability alteration by aging

The outcrop chalk is naturally strongly water wet. Therefore, to be able to carry out experiments at different wettabilities ranging from strongly water wet to near-neutral wet, a reproducible wettability alteration method had to be derived.

A reproducible method of altering the wettability in outcrop rock has been reported in Graue et al., 1995, 1999b; Eilertsen et al., 1999. This technique has successfully been applied in laboratory studies of how oil recovery mechanisms in fractured reservoirs change depending on the wettability conditions, as described in the enclosed scientific papers.

In Paper 1, heterogeneous wettability conditions, created by aging in crude oil, had bearing on the interpretation of the oil recovery mechanisms in fractured blocks of chalk at different wettability conditions.

Visualization of the effects of various wettability conditions on oil recovery in fractured chalk reservoirs was demonstrated in two-dimensional in situ imaging experiments in large blocks of chalk and by numerical simulation. Recovery mechanisms changed with wettability. See for instance Paper 3 and 5. Iterative comparison between experimental work and numerical simulations was used to predict oil recovery mechanisms in fractured chalk as a function of wettability. In large-scale nuclear tracer, 2D-imaging experiments waterflooding blocks of chalk were monitored, first for whole blocks and then for fractured blocks. Capillary pressure and relative permeabilities at each given wettability were measured (Paper1) and used as input for the simulations. The results from these studies emphasize the importance of close interaction between the method applied to alter the wettability and the interpretation of the experiments at various wettability conditions.

Paper 2, in particular, investigates why and how the wettability after aging in crude oil under certain conditions produces a non-uniform distribution. Included in this study also are the results on the significance of some selected parameters that demonstrate how crucial it is to be consistent in the choice of all experimental constants.

Not knowing that a heterogeneous wettability distribution is present may seriously affect the interpretation of laboratory experiments. An example of a variation in wettability during aging of core plugs submerged in crude oil has been reported (Spinler et al., 1999). The phenomenon was observed through the variation in capillary pressure scanning curves, detected by NMR-imaging, across the cross section of the aged core plugs.

A full description of the wettability alteration method can be found in paper 1 and 2. A summary follows;

Stock tank oil was used as the crude oil and in-line filtered through a chalk plug, CP-15 Table 4, at 90ºC before it was used to oilflood the samples to initial water saturation.

The following procedure for preparing the crude oil was used: The barrel containing crude oil was shaken and the crude oil was tapped from the centre of the barrel, and stored at 20°C in closed containers until it was filtered. While establishing $S_{wi,}$ the plug was sequentially flooded from both ends.

For the chalk cores, oil flooding at 8 bars differential pressure gave initial saturations in the range 25-30%. The initial water saturation used in this study was 25% PV.

The core samples, at initial water saturation, were aged in closed, crude-oil-filled containers using an oven set at 90.0±0.5°C for different lengths of time. All aging was performed in duplicate sets of plugs to determine experimental repeatability.

Core weight was measured both before and after aging to determine whether any water evaporated.

After aging the crude was displaced by 5PV decahydronaphthalene (decalin), at 90°C. The decalin was flushed by injection of 5PV decane, at 90°C, before the temperature was lowered to room temperature.

The decane then represented the oil phase throughout the experiment. Decane has been shown to not alter wettability in chalk. Decalin was obtained from Pihl Inc. and had an isotopic purity of >98 %.Decane was obtained from Pihl Inc. and had an isotopic purity of >95 %. Both hydrocarbons were used as received.

The core plugs containing brine and decane were cooled to room temperature for at least 12 hours and then placed in a graduated imbibition cell. Produced oil as a function of time was measured volumetrically.

Before each measurement, the imbibition cell was gently shaken to displace the oil drops adhered to the cell and core surface.

When the cores stopped producing oil they were water flooded at high rates (1 cm^3/min.) to drive them to a viscous endpoint.

The aging technique was found to be reproducible and could alter wettability in Rørdal chalk selectively, from strongly water-wet to nearly-neutral-wet. A consistent change in wettability towards a less water-wet state with increased aging time was observed.

3.5 Large block waterflood experiments

In large block experiments viscous, gravitational and capillary forces are acting at the same time. In addition we are able to observe the impact of various fracture networks, at different wettability conditions. The large block waterflood experiments are described in detail in paper 3. A brief summary follows;

Wettability alteration and QC:
A North Sea crude oil, filtered at 90°C through a chalk core, was used to oilflood the block and to determine the aging process. Two twin samples drilled from the same chunk of chalk as the cut block were treated similar to the block. An Amott-Harvey test was performed on these samples to indicate the wettability conditions after aging. After the waterfloods were terminated, four core plugs were drilled out of each block, and wettability measurements were conducted with the Amott-Harvey test. See Figure 3.4;

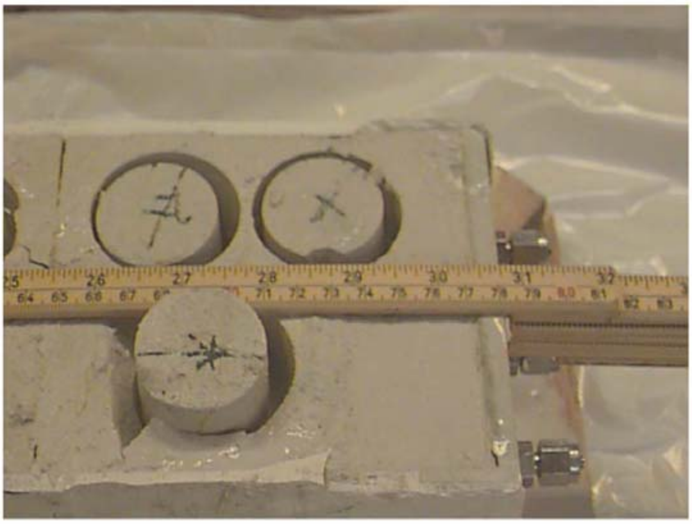


Figure 3.4 Drilling of core plugs from blocks to verify wettability conditions.

Because of possible wax problems with the North Sea crude oil used for aging, decane was used as the oil phase during the waterfloods, which were performed at room temperature. After the aging was completed the crude oil was flushed out with decahydronaphthalene (decalin), which again was flushed out with n-decane, all at 90°C. Decalin was used as a buffer between the decane and the crude oil to avoid asphalthene precipitation, which may occur when decane contacts the crude oil.

Fracture generation:

The fractures were created after the first waterflood, when the whole block had been driven back to Swi, by cutting the block with a band saw. The fracture orientation and location and a diagram of the arrangement of the individual pieces of the designed fracture network, after the individual cut blocks were reassembled, are shown in Figure 3.5. Both open fractures, with no possible capillary contact, and several closed fractures, with contact between the adjacent matrix blocks, were formed.

For all the fractured blocks, the first vertical fracture was at 4 cm from the inlet end, the second vertical fracture was at 13 cm from the inlet end, and a horizontal fracture was created at the centre line of the block, connecting the vertical fractures. This fracture network is denoted as the embedded fracture network. For the interconnected fracture network, two horizontal fractures were added at the inlet and outlet ends to provide continuous hydraulic contact from inlet to outlet. The blocks were positioned vertically for both the oilfloods and the subsequent waterfloods; thus, the gravity was aligned with the vertical fractures.

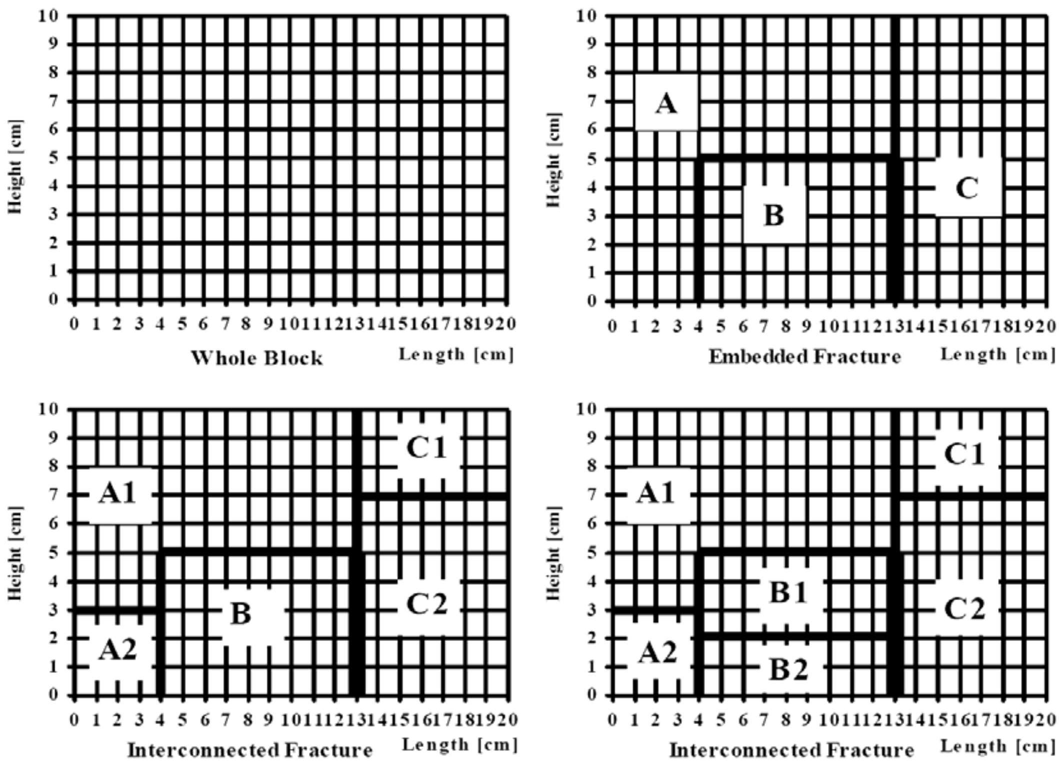


Figure 3.5 Various fracture networks.

Saturation determination during waterflood:
The waterflood experiments were performed using the 2D rig constructed at the University of Bergen. The rig holds the block in a vertical position and measures the radiation in the x-y plane over the block to produce a saturation map at each specified point in time. Radiation detection (i.e., saturation measurement) during the waterflood was made at the intersections in the grid shown in Figure 3.5, a 1x1-cm grid.

It is important to ensure that the collimation volume (usually 15 cm3) is as small as possible. Also the delta saturation in a single volume element from one scan to another should be as small as possible (usually 0.02 PV). Respecting this, no correction had to be made to account for the saturation change during the scanning time.

When the blocks were fully saturated with radioactive brine, the counts of radioactivity at each gridpoint were normalized to 100% water saturation. The normalization coefficients at each gridpoint were then used to convert the radiation measurements into saturation distributions in all later images.

To prevent counter-current imbibition from producing oil into the water inlet, a low differential pressure, initially 1.5 kPa, was applied across the block during the constant-flow-rate waterfloods. The water injection rates were low – usually in the order of 1 ml/hr.

3.6 Centrifuge experiments

The work in this thesis is partially focused on comparing conventional centrifuge methods with direct measurement of saturation methods, with the ambition to develop a new method for measurement of capillary pressures using nuclear tracers.

Paper 1 describes in detail the experimental procedure of the conventional centrifuge techniques used to measure the capillary pressure curves at different wettabilities:

11 core plugs were prepared to measure capillary pressures. The core plugs were all 3.8cm in diameter and ca. 4cm long. Porosity was measured at 43-48% and permeability was 3-5mD. The capillary pressure data was obtained by the standard centrifuge technique, running three samples at a time. Room temperature imbibition characteristics were taken, after aging, for all of the eleven core plugs, containing brine and decane. Imbibition characteristics for two typical strongly-water-wet core plugs were used for comparison.

The three cores prepared to a wettability condition of Iw=0-0.1, using a total aging time of 50 days, did not imbibe any significant amount of water and exhibited water saturation endpoints after imbibition of less than 30%PV. These cores stood out as odd samples according to our experience with the aging technique. Measuring the capillary pressure for one of theses samples using direct measurement of saturation with Magnetic Resonance Imaging (MRI) after elevated temperature centrifuging with oil that solidifies at room temperature exhibited a range of wettabilities with the outside edge of the plugs less water-wet than the inside.

A subsequent high rate waterflood, 34ml/hour for all plugs exhibited final water saturation in the range of 63-70%PV. Endpoint effective permeability to water at residual oil saturation for all cores was less than 2mD.

Paper 6 describes in detail the experimental procedure for the direct measurement of saturation – i.e. the capillary pressure scanning curves – at various wettabilities, and their comparison with the measurements of the curves in Paper 1:

MRI tomography was used as the high spatial resolution imaging technique required for the DMS method. After establishing the desired wettability, decane was replaced by octadecane at 45°C at S_{wi}. The cores were then cooled to room temperature. Octadecane solidifies at 27°C, hence the oil phase could now be considered immobile. The core plugs were imaged by MRI to obtain the initial water saturation distribution.

A free water level around the lower part of the cores, determining the position of zero capillary pressure, was established with octadecane above. The cores were then spun in a centrifuge at 3300 RPM for 1 week. By increasing the temperature after the centrifuge reached the desired rotational speed the oil phase became mobile with both spontaneous and forced imbibition starting upon exceeding the 27°C melting point of octadecane. Spontaneous imbibition occurred in the area above the free water level, forced imbibition in the part of the core below the free water level.

To obtain the S_w = 100% calibration profiles, the cores were flooded with deionised water to remove the salt before being dried under vacuum. The cores were then 100% saturated with brine before MRI-imaging to be able to normalize the MRI image intensities from the prior images. A calibration curve was obtained by draining and imbibing the plug under air and using gravimetric means to measure average brine saturation and whole plug MRI profiles to obtain relative MRI intensities for the various brine saturations. Thus absolute values for water saturations were obtained and the saturations for the capillary pressure curves were calculated. The corresponding pressure field for Pc was determined from the standard centrifuge equation.

Paper 7 describes in detail the experimental setup for the feasibility phase of the ongoing study at the University of Bergen, aiming to develop a new measurement technique allowing to measure in-situ capillary pressures at different wettabilities using live crude oil at reservoir conditions:

The method uses nuclear tracers to measure in-situ saturations while the core plugs are spinning in a centrifuge. The apparatus consists of

1) A centrifuge with swinging bucket type core holders, capable of achieving and holding reservoir conditions with respect to pressure and temperature while spinning and
2) An imaging system using nuclear tracers to obtain the in-situ saturations in the core plugs while spinning in the centrifuge.

The potential advantages of this system compared to existing methods of in-situ measurements of capillary pressures are that

1) Crude oil may be used, even at reservoir conditions,
2) Capillary end effects are directly measurable,
3) No assumptions are needed to calculate the capillary pressure since the local fluid saturations are directly measured at various capillary pressures and
4) There is no need to solidify one of the phases and remove the cores, as in the direct saturation measurement or DMS method.

The centrifuge is a Beckman J-6B with a rotor that carries four individual core holders. The core holders are capable of holding a confinement pressure up to 300 bars. The centrifuge/rotor has a maximum speed of 3600 rpm, which translates to a maximum capillary pressure of about 3bar for a brine/decane system in a 6cm long plug.

The detector is mounted on top of the centrifuge with a collimator focusing on an adjustable 2 – 4mm cross-section of the cores. In the feasibility study, one of the cores contained a radioactive labelled fluid, in one of the core holders below the detector. Thus no gating of the detector was needed. While the centrifuge is operating, the detector needs to be moved horizontally along the centrifugal axis to measure the radioactivity at selected locations along the plug.

A steel cylinder with 20 cm thick walls was placed around the detector to minimize signal from background radiation. The sodium iodide detector was a Canberra NaI(Tl) detector with a 2”x 2” crystal. The signal was counted and stored using a Canberra multi-channel analyzer.

3.7 Numerical Simulations

Using the experimental values for capillary pressure and relative wettability found earlier in the study, as input, numerical simulations of the large block waterfloods have been performed. Both Sensor and Eclipse numerical simulators were used, basically with the same setup. See Figure 3.6 and 3.7 for examples. Simulation-grid fitting the dimensions of the blocks, injection and production wells, as well as local grid refinement around fractures was constructed. The approach for the dynamic simulation of the large block waterfloods are described in detail in paper 5:

Initial simulations were run using the experimental measured values for capillary pressure and relative permeabilities at the different wettabilities, and then compared to the experimental data.

Improvement of the history match for both the oil production and the match of the dynamics of the in-situ fluid saturations, optimization of capillary pressure curves was carried out keeping the relative permeabilities from the core analysis results constant, and then vice versa, using the capillary pressure from the centrifuge measurements and optimize the relative permeabilities. This procedure would also give information on which of the measured values could be most trusted.

When the waterfloods were completed, the experimental results on the wettability measurements of the core plugs drilled out of the blocks became available. The results revealed that the block had a wettability index to water, I_w=0.8, rather than at I_w=0.5 as indicated by the twin samples. This has later been shown to be an artefact of the practical arrangement during aging as described in paper 1 and 2.

Due to lack of accurate information on the positive portion of the capillary pressure imbibition curve for the wettability Iw = 0.8, three realizations for the numerical simulation of the whole block waterflood were performed using three different representations of the positive capillary pressure curve. This procedure indicated which of the capillary pressure curves would best represent the capillary forces at moderately-water-wet conditions, Iw = 0.8.

This procedure was meant also as a test of the interpretation of the significance of the spontaneous imbibition on the recovery mechanism at moderately-water-wet conditions. If the higher or the medium capillary pressure curves would give the best history match the capillary forces would accordingly be more dominant during the oil displacement at lower water saturations. If the lower capillary pressure curve gave the best match, the viscous forces would be dominant and assist in the displacement of mobile oil. For the higher capillary pressure imbibition curve we kept the Pc-value high even near the endpoint for spontaneous imbibition to reflect an abrupt drop in capillary pressure sometimes experienced near the endpoint for spontaneous imbibition in water-wet high capillary chalk. This might be interpreted as when the non-wetting phase becomes discontinuous and trapped. This has previously been observed during capillary pressure measurements at strongly water-wet conditions using the Direct Measurement of Saturation method as described in paper 6.

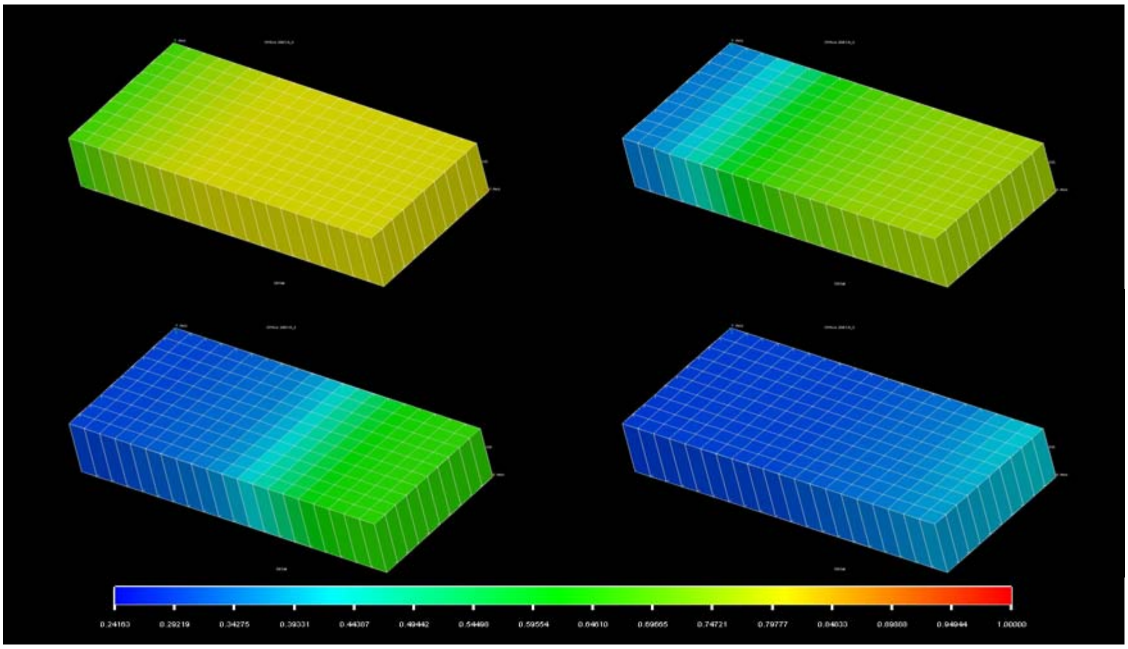


Figure 3.6 Simulation of a large unfractured block waterflood, using Eclipse.

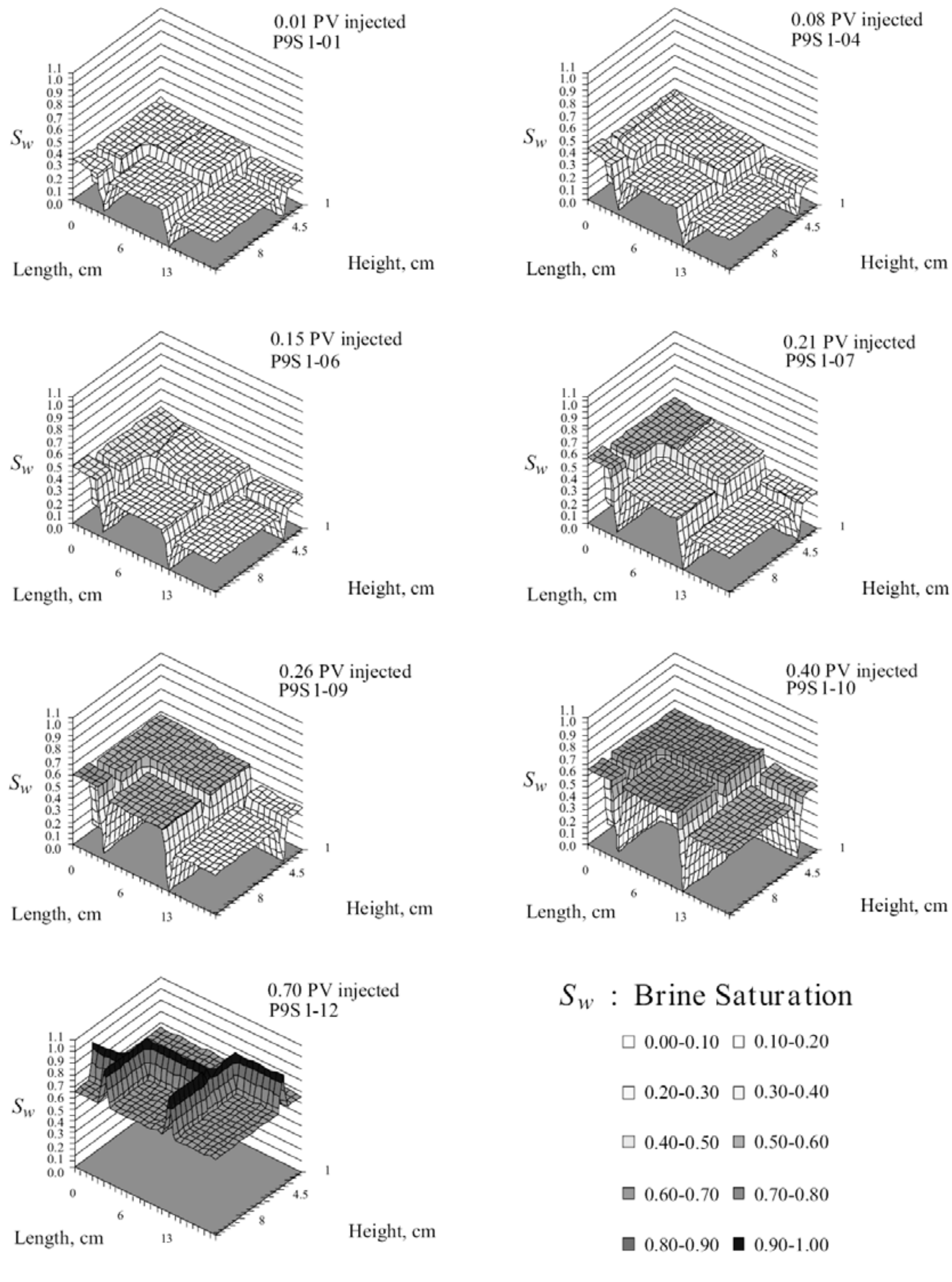


Figure 3.7 Simulation (Sensor) of a large block waterflood on a strongly water wet block using the interconnected fracture network.

4 – Results and discussion

4.1 Introduction

The work presented in this thesis has improved the understanding of the interaction between wettability and fractures on the production mechanisms in carbonate reservoirs, in different directions. Figure 1 gives an overview of the project "Capillary Pressures and Capillary Heterogeneities", its fundamental building blocks and the interaction between them to better understand how main conclusions in this study may be drawn;

Building block 1:
A reproducible method for altering wettability has been developed, and continuously improved throughout the study. Feed-back from the large scale block experiments have actively been used to improve the wettability alteration technique, in particular when it comes to radial and lateral wettability heterogeneity. This is further described in paper 1 and 2.

Building block 2:
The study of fracture crossing mechanisms at different wettabilities has improved the understanding of the production mechanisms in fractured chalk. The observations in the large scale block experiments have been used to understand the results of the fracture crossing experiments and vice versa.

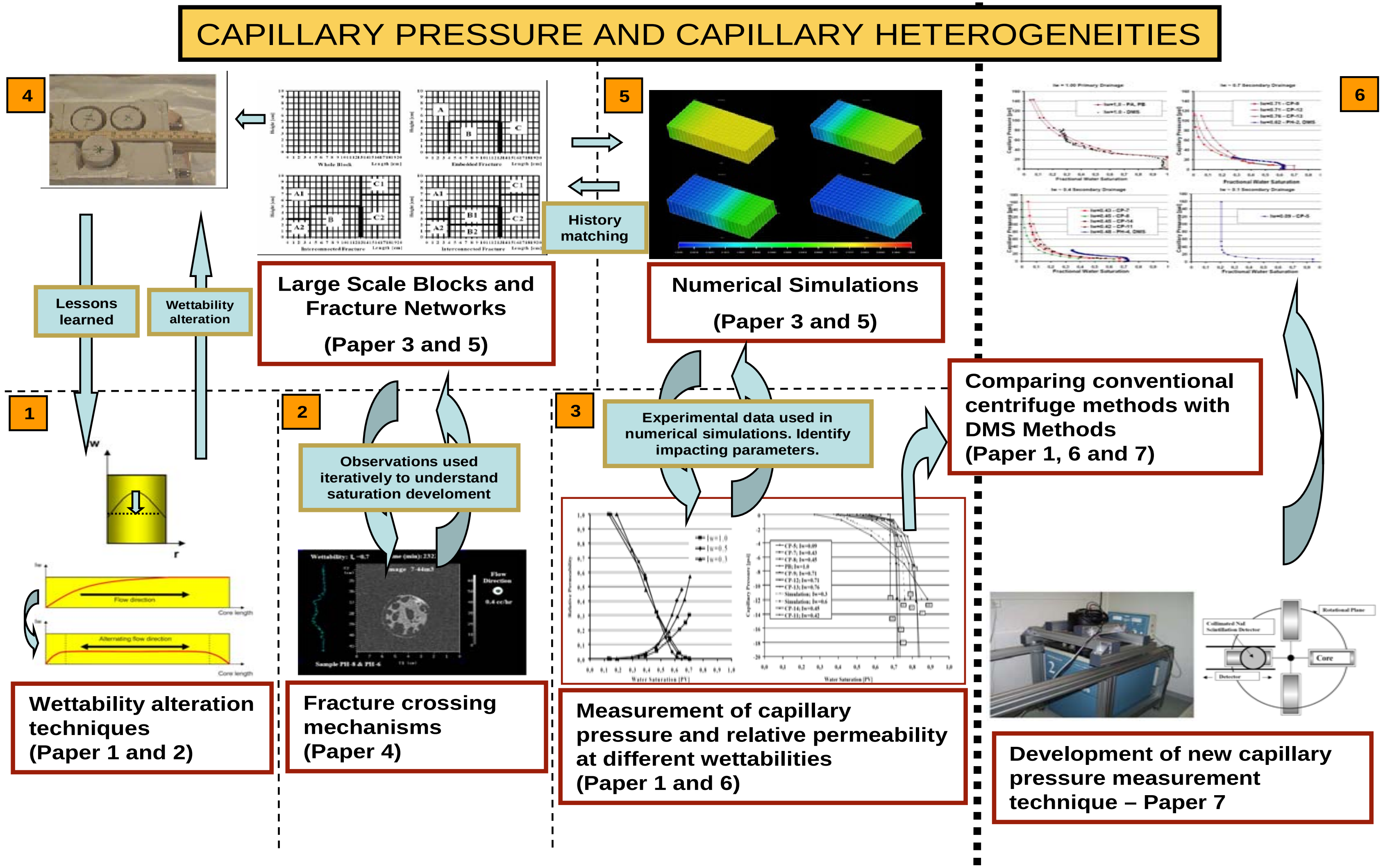
Building block 3:
Capillary pressure and relative permeability curves have been measured at different wettabilities. The capillary pressure curves in particular, have also been measured using different centrifuge methods. The experimental results have actively been used in numerical simulations. The numerical simulations in return have been used as QC for the experimental results, especially when measuring the spontaneous and forced imbibition curves.

Building block 4:
Large scale waterflood experiments have been performed at different wettabilities, using different fracture networks, measuring the in-situ saturation development. This has led to an improved understanding of the production mechanisms in this type of reservoirs.

Building block 5:
Numerical simulations have actively used the experimental data obtained from the large scale block experiments and the capillary pressure/relative permeability, and at the same time provided an improved understanding on the potential impacts of changing the parameters. It has also helped us to improve the interpretation of the results.

Building block 6:
The outlines of a method for measuring in-situ capillary pressures at different wettabilities have been presented, and a feasibility study performed. If this method is further developed and successful, it could be possible to measure in-situ capillary pressure curves using live crude oil at reservoir conditions. This work is reported in Paper 1, 6 and 7.

Fig. 4.1 – Focus areas for this study



4.2 Wettability alteration

To be able to produce reliable results in the waterflood experiments, and capillary pressure measurement experiments, it is a prerequisite to fully understand the wettability alteration mechanisms.

At the University of Bergen the methods for altering wettability by aging has been constantly developed and improved in an iterative process with the lessons learned from the waterflood experiments. The approach has from the origin has always been to alter the wettability of the outcrop chalk by exposing it to crude oil at high temperature for a certain amount of time.

Originally chalk core plugs were drained to initial water saturation by crude oil and then submerged into glass jars of crude oil, keeping the temperature at 90°C at all times. Spinler et al. (1999) showed through in-situ saturation imaging experiments that this method produced a radial capillary heterogeneity, due to an assumed strong diffusion of polar components at the outer face of the core plugs. Furthermore another capillary heterogeneity was observed from core inlet to core outlet, in cores that has been drained by crude oil in a unidirectional process. The core plugs tended to be more water-wet the longer distance to the core inlet.

The same behaviour was observed when testing the wettability of core plugs drilled from the large scale blocks after waterflooding. Also these core plugs exhibited heterogeneous behaviour as a function from inlet of the original block.

The increased efficiency for altering wettability observed when continuously flushing the core plug with crude oil during aging indicated that increased concentration of some ‘‘active’’ components accelerated the aging process. Concern about potential absorption of these components as function of core length resulted in an experiment schematically illustrated in Figure 4.2.

Five core plugs were stacked in a core holder and continuously flushed in one direction during 72 h of aging. The initial water saturation was 25% PV and its distribution, measured with a nuclear-tracer technique. The in situ water saturations before imbibition, after spontaneous brine imbibition and after the subsequent waterflood (to obtain the Amott index) are completed. The solid line in the figure indicates the distribution of the Amott index to water as calculated by material balance.

An experiment was designed to test the effect of reversing the oilflood direction during aging in a 15-cm long, 2-in diameter core plug. In this experiment, the direction of continuous oil flow, with a flow rate of 2 pore volumes per day (PV/ day), was changed four times during the aging process. The initial water saturation distribution, the water saturation distribution after the spontaneous imbibition and the final water saturation distribution after the waterflood to obtain the Amott index to water are plotted in Figure 4.2. The solid line in the figure indicates the distribution of the Amott index to water as calculated by the in situ water saturation measurements. The middle section of this core would provide a core plug with homogeneous wettability conditions.

If a shorter core plug is extensively flushed in both directions, the results show that a fairly uniform wettability distribution will be obtained. Our experience is, however, that the results of an imbibition test may be improved by cutting away the inlet and outlet face of the plugs and use in situ saturation imaging to obtain the saturation development.

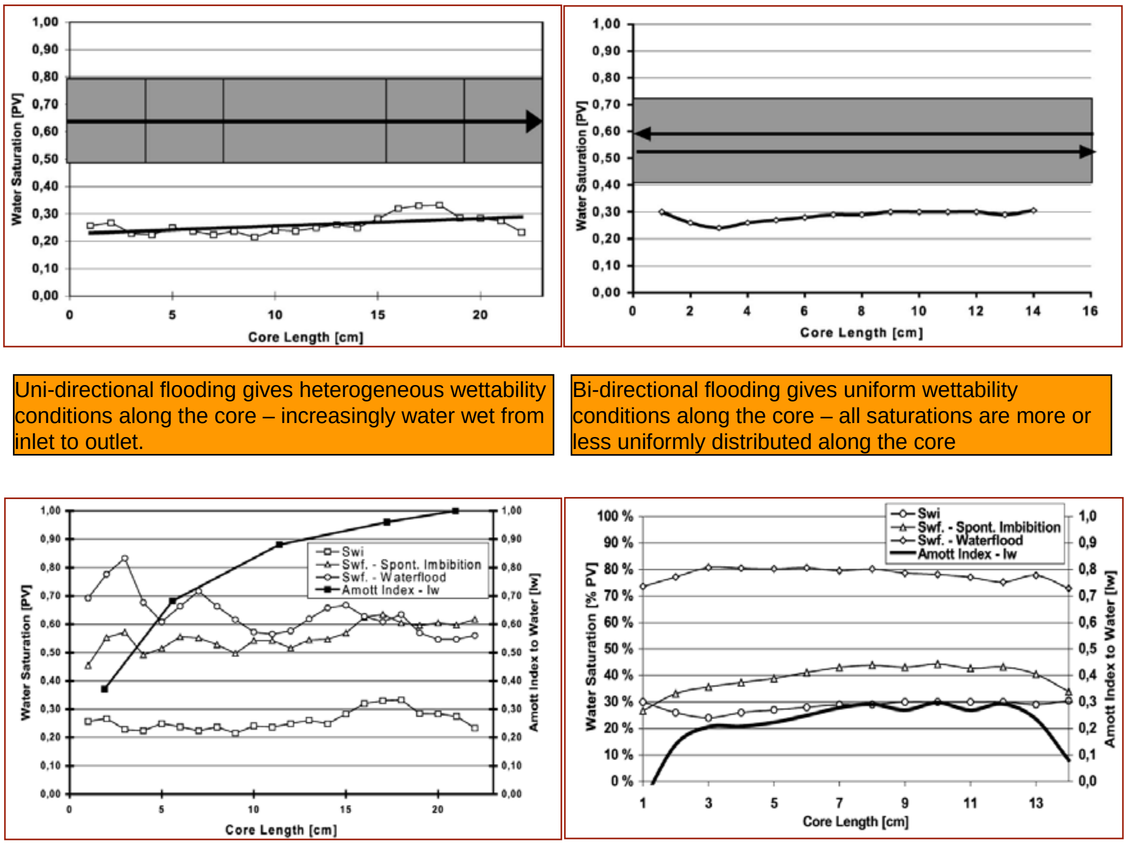


Figure 4.2 The effect of bi-directional flooding of crude oil to improve the homogeneity of the wettability alteration. To the left uni-directional flooding and the resulting distribution of Amott index. To the right the same results using bi-directional flooding.

These observations led to the development of a new aging method, based on continuously flushing crude oil, bi-directionally.

The development in wettability alteration by aging is described in detail in paper 1 and 2, with the main conclusions of the work given below;

- Imbibition characteristics for cores treated to less water-wet conditions show a reproducible and stable wettability condition obtained.
- Wettability alteration by submerging core plugs in crude oil and age for longer time may cause capillary heterogeneities.
- Wettability alteration by aging in crude oil is more efficient if crude oil is continuously flushed through the cores, bi-directionally.
- If crude oil is flushed in only one direction, wettability variation may be observed.

- Efficiency of wettability alteration is also strongly dependent on the initial water saturation and crude oil composition.
- The observations of wettability variations within the core material, radial or along the core, was confirmed by numerical simulations.

Further work on wettability heterogeneities and improvements of the wettability alteration techniques is reported by Aspenes (2006).

An understanding of the wettability alteration mechanisms is important in field development. The experiments carried out in this study shows that the wettability is a function of initial water saturation, crude oil composition, oil rate, rock composition, and time. In a field development these observation may translate into the following observations when trying to map the wettability conditions of an oil reservoir;

- Wettability is dependent on the initial water saturation and different capillary heterogeneities should be implemented in both static and dynamic model as a function of the reservoir J-function.
- A full PVT study based on oil and water samples taken at different depths in the reservoir would describe the potential variations in crude oil composition, taking into account effects like biodegradation etc., and could help to quantify the wettability variations.
- Sedimentary synthesis, description of diagenesis, and trapping/migration history may help to understand the amount and quality of oil that has migrated from source rock to reservoir rock, at which time and at which temperature.

4.3 Impacts of wettability on capillary pressure and relative permeability

Multiphase flow in porous media is strongly dependent on the wettability; surface interactions between two or more immiscible phases and the surface of the porous rock. The impact of capillary forces is usually represented by capillary pressure and relative permeability. To be able to understand the production mechanisms of fractured chalk at different wettabilities it is necessary to see how these two functions varies at different wettability conditions. The major part of this work is reported in paper 1.

First observation that can be made when assessing the impacts of wettability is the difference in behaviour during capillary imbibition. The proportion of spontaneous imbibition to forced imbibition is altered when moving from strongly water wet (100% spontaneous imbibition) to neutral wet (0% spontaneous imbibition). Moe (2007) made an overview of the Amott Index to water for most core plugs used in experiments at the University of Bergen. The overview clearly demonstrates this effect. See Figure 4.3.

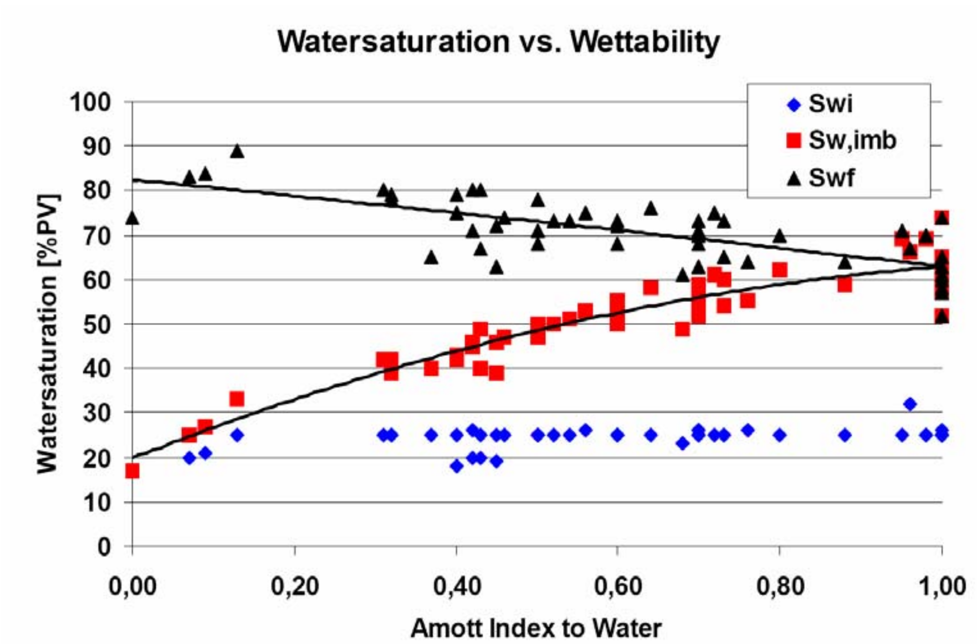


Figure 4.3 From Moe 2007 – Sw development vs. Amott index to water.

Capillary pressures were measured at different wettabilities ranging from strongly water wet to near neutral wet. Both drainage and forced imbibition curves were measured – see Figure 4.4 below. The results obtained for the drainage process indicates lower threshold pressure – 25 psi vs. 7 psi - and more curvature at less water wet conditions, consistent with theory. The very low immobile water saturations are related to the Hassler Brunner correction performed to move from average material balance saturations. The forced imbibition measurements show a flatter curve for less water wet conditions, consistent with theory. The potential for increased oil recovery by introducing a small pressure gradient, either by viscous forces or gravitational differences, is significant. Closer to neutral wet, the pressure gradient needed to mobilise the same oil is higher. The residual oil saturations are lower at near neutral wet condition – in the order of 30% at SWW compared to 11% at LWW.

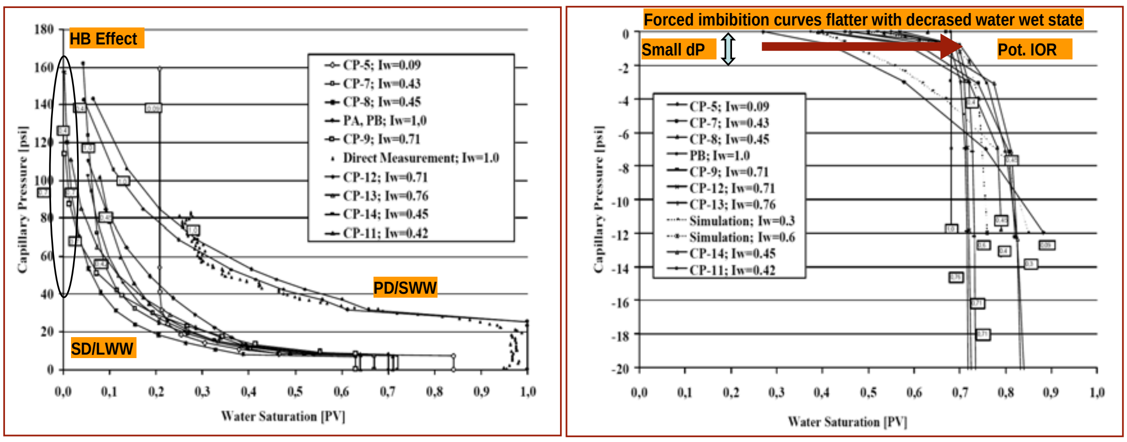


Figure 4.4 Capillary pressure measurements at different wettabilities.

A capillary pressure curve for a strongly water wet core measured using DSM was also included for comparison. The measurement was in very good agreement with the results obtained using the conventional centrifuge techniques.

Relative permeability curves were also measured at different wettabilities, using the Penn State steady stare measurement technique. The results showed relative permeability curves consistent with earlier tests reported in the literature. The trends observed were an increasing water relative permeability when moving towards less water wet conditions. For Iw=0.5, there was however an anomaly observed, as the curve was not in between the SWW and LWW curves for higher water saturation. There is reason to believe that the wettability condition of this particular core plug was a mixed wettability state, with some oil wet areas, since the forced imbibition capillary pressure curve showed resistance to water injection. The residual oil saturations were not consistent with earlier observations, as lower residual oil saturation was expected when moving towards a less water wet state.

These types of observations are instrumental when developing fractured reservoirs that may contain capillary heterogeneities, and show the importance of a thorough conventional and special core analysis study before launching a full field development. A SCAL study allows mapping the potential variation in recovery mechanisms from WOC to crest of the structure, or within the different reservoir facies. Each different combination of recovery mechanisms may need their own approach to achieve an optimal recovery factor, with respect to injection rates, injection pressures, well design, and completion of producers.

4.4 Large scale waterfloods and numerical simulations

The large scale waterflood experiments enables to monitor the in-situ saturation development in fractured reservoirs at different wettabilities. In this type of experiments all the most important forces present in a full scale oil field development, plays their role. The capillary forces are ever present, and their impact is determined by the wettability distribution and the degree of capillary contact in the fracture networks. The viscous forces are also present, although determined by imposed pressure gradients/water injection rates, and the mobility of the fluids present in the displacement. The gravitational forces are also present, due to the 3 dimensional nature of the block, both in the fracture network at varying capillary influence and in the matrix at varying viscous influence.

This type of experiments has a long history within the research group at the University of Bergen. Prior to the author’s work, similar studies have been reported by Viksund et al. (1997) and Graue et al. (1999). The author’s contribution has been two block experiments, strongly water wet and moderately water wet, with an embedded and interconnected fracture network. This work has been continued by Moe (2007).

The experimental details of the chalk block experiments are described in paper 3 and 5.

Both strongly water wet and moderately water wet cores were waterflooded from uniform initial water saturation, using different fracture networks. The in-situ saturation development was monitored. Experiments like these tell us how the fracture network is affecting the multiphase flow, and ultimately which production mechanisms are governing the co-current imbibition in each matrix block. We are able to observe that the water movement is significantly affected by fractures at strongly water wet conditions, while at moderately water wet conditions no effect may be observed. This indicates that the flow is more dominated by capillary forces at strongly water wet conditions – which is in line with expectations.

Block CHP9 was waterflooded at strongly water-wet conditions with an interconnected fracture network. Block CHP8 was, after subsequent oilfloods, waterflooded three times at moderately water wet conditions, first as a whole block, then with the embedded fracture network, and finally with the interconnected fracture network.

To obtain a measure of the wettability conditions of CHP8, the block was aged to reflect moderately water-wet conditions using the uni-directional aging technique, and a duplicate set of core plugs, PC2-13 and PC2-15, were tested for wettability. The cores indicated a wettability of Iw at 0.5.

Repeated imbibition tests on the core-plugs after aging confirmed stable wettability conditions. The measured wettability index to water, Iw, for the two plugs was recorded at 0.52 and 0.54, respectively. The Amott-Harvey test was conducted three times on these samples to verify stability and reproducibility in the measurements.

The term "moderately water-wet" means to cover the wettability conditions, reflecting Amott-Harvey water index, Iw, in the range of 0.5 to 0.8.

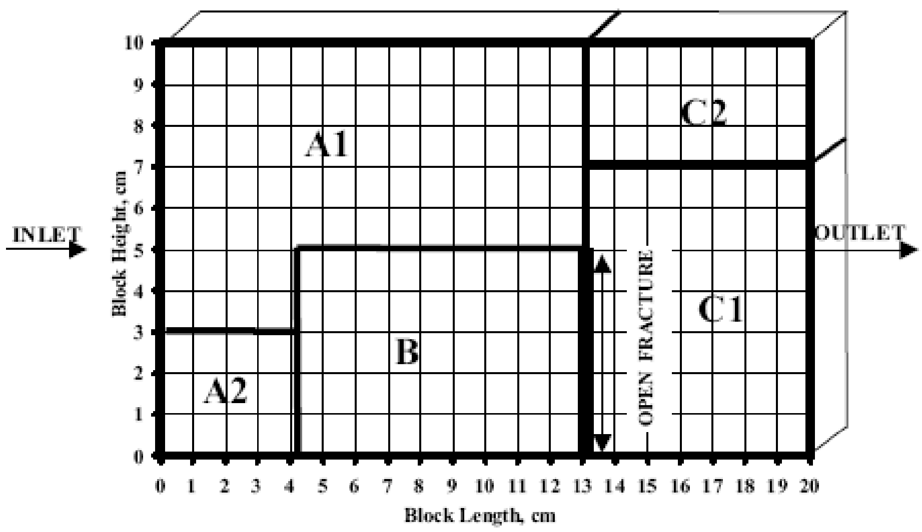


Figure 4.5 The interconnected fracture network.

The impact of fractures at SWW and MWW conditions may be illustrated by comparing waterfloods on two different blocks at different wettability, using the same fracture network. See Figure 4.5 for description of the fracture network and Figure 4.6 for a comparison of the in-situ saturation development.

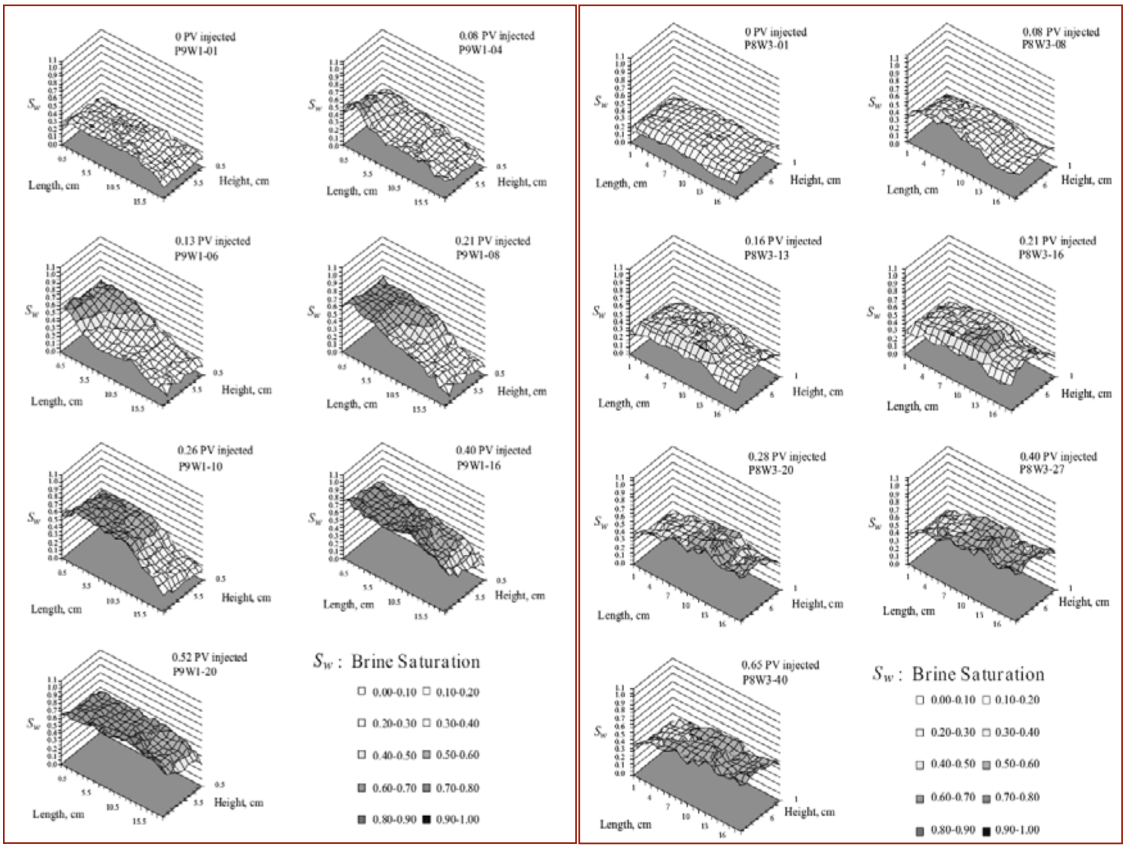


Fig. 4.6 Waterflood of 2 large chalk blocks. Left; strongly water wet conditions with interconnected fracture network. Right; moderately water wet conditions also using interconnected fracture network.

For the SWW Block the following observations were made (Paper 3):

- The brine saturation increased as a dispersed front through Block A, the continuous inlet block, Scans P9W1-01 through P9W1-20.
- In Scan P9W1-08, Block B was still at, or close to, Swi while the matrix just across the fracture in Block A was approaching Swf. This suggested a limited rate of transport of fluids across the closed vertical fracture at 4 cm and the horizontal fracture at 5 cm. In fact, the brine did not appear to cross any of the fractures before the saturation in all of Block A was close to its final water saturation.
- After Block A reached a high saturation and the fractures were filled with brine, the brine entered Block B, Scan P9W1-10. The general appearance of Block B in Scan P9W1-10 suggested that the brine entered gradually from both the horizontal and vertical fractures between Block A and Block B.
- However, little, if any, water had gone across the 13-cm fracture into Block C when Scan P9W1-10 was taken. When Block B approached its final water

saturation, water movement into Block C, the outlet block, was recorded (Scan P9W1-16).

- Higher water saturation in the lowest part of Block C at the outlet end, shown in Scan P9W1-16, indicated a gravity segregation of the fluids in the open fracture.

For the MWW Block the following observations were made (Paper 3):

- The brine saturation increased as a dispersed front through Block A, the continuous inlet block, and Block B (Scans P8W3-01 through P8W3-40). No visible influence from the fractures was observed.
- This suggested a significant transport of fluids across the closed vertical fracture at 4 cm and the horizontal fracture on the centerline of the block.
- This indicated
    - capillary contact across the closed fractures at moderately water wet conditions,
    - a reduced capillary threshold pressure for water breakthrough owing to a less water-wet state, or
    - a mechanism where continuity in the wetting phase (the water) was established
- As opposed to the water-wet case, gravity segregation in the open vertical fracture was not observed in this block.
- The water entered Block C from the closed vertical fracture at 13 cm, with no visible influence from this fracture.
- The upper left corner near the inlet of the block was poorly waterflooded, probably because of the increased permeability in the lower section of Block A, caused by hydraulic continuity by the horizontal fracture from the inlet.

In terms of final oil recovery, a small difference was observed when comparing whole block and interconnected fracture network. Production profiles also indicate earlier breakthrough of water – and longer period of two phase production. This observation was the same regardless of different wettability conditions. This is consistent with the assumption that after fracturing, the permeability increased owing to the horizontal fracture along the center line of the blocks. The interconnected fractures increased the endpoint relative permeability to oil at immobile water saturation by a factor of 42.

A difference in water movement was observed in the two cases. In the SWW case we would expect that the water would enter block C through the closed part of the fracture at 13 cm. Contrary to this, the gravity segregation of the fracture indicates fairly open fractures. In the MWW case the water crossed the same fracture into block C – even the open part of the fracture had a visible impact. This indicated that the influence of the closed fractures on the flow pattern during waterflood was reduced as the wettability was changed toward moderately water-wet conditions.

We speculate that the reduction in capillary holdup of the wetting phase at less-water-wet conditions is the reason for this. Another interpretation could be that water droplets at the fracture may form and establish wetting-phase bridges across the fractures when the contact angle increases as wettability is changed to less-water-wet.

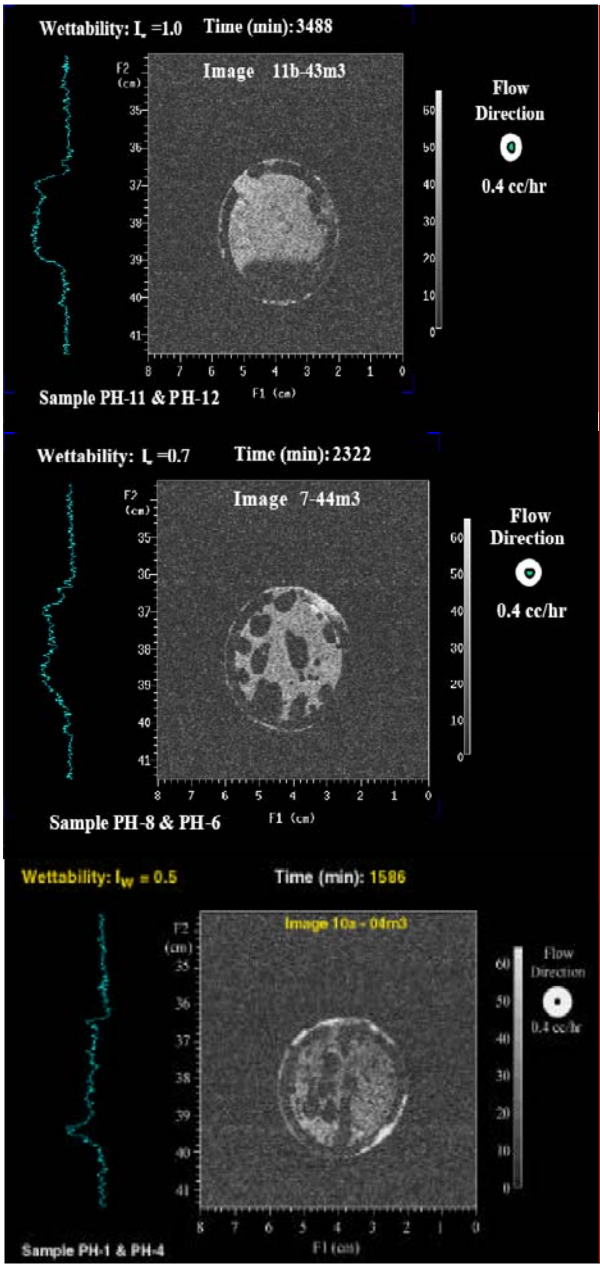
This displacement mechanism depends on the fracture aperture and the viscous pressure in the wetting phase (i.e., the applied differential pressure and the wettability conditions, reflected by the increase in contact angle). We believe one of these two mechanisms, or a combination of the two, are responsible for observing less impact from the fractures on the waterflood at less-water-wet conditions.

At strongly water wet conditions the waterflood was affected by fractures – at moderately water wet conditions – not. This points not only to a difference in the strength of the capillary forces, but also a change in the very fracture crossing mechanism it self. Experiments were designed to observe the fracture crossing mechanisms at different wettabilities. These are described in detail in paper 4.

At strongly water wet conditions; water did not cross a given fracture before the end point saturation for spontaneous imbibition was reached. As expected in flow 100% dominated by capillary imbibition, the counter-current imbibition rate was high enough and, capillary continuity good enough to prevent the injected water to progress beyond the displacement front of the matrix. When water entered an open fracture with no capillary continuity, the fracture was filled bottom-up, quickly.

At moderately water wet conditions; wetting phase bridges were formed before the endpoint for spontaneous imbibition was reached. The water could the readily flow into the next matrix block, even if the capillary imbibition process was still ongoing in the inlet block. At less water wet conditions; the wetting phase bridges formed even earlier.

This has further been investigated in Paper 4. Here the actual fracture crossing as been imaged using MRI, and the bubble growth at the exit face of a core plug has helped us to verify our interpretation from the waterflood experiments. On fracture crossing the main conclusions were as in Figure 4.7 below:



At strongly-water-wet conditions, Iw=1.0, water did not cross an open fracture before the water saturation endpoint for spontaneous imbibition was reached at the inlet plug's outlet face. When water entered the fracture the fracture was quickly filled from the bottom.

At moderately-water-wet conditions, Iw=0.7, wetting phase bridges were formed before the spontaneous imbibition endpoint was reached, causing water to readily flow across a 1 mm open fracture before Pc became zero at the inlet plug's outlet face. The advancing waterfront was dispersed causing the fracture to slowly fill while water simultaneously continued to flow across the fracture.

At less-water-wet conditions, Iw=0.5, similar flow characteristics as for Iw=0.7 were observed, but the wetting phase bridges appeared to form earlier and grew larger in size, allowing, as in the previous experiment, the water to cross the 1 mm open fracture.

Figure 4.7 Fracture crossing mechanisms at various wettability.

Fernø et al. (2007a,c) presented further work on fracture flow, and fracture matrix transfer. In the light of the results presented above, and more in detail in Paper 4, it is at least from an academic point of view interesting to see if the observed effects are the same when oil-flooding an oil-wet core plug. Series of oil-water and water-oil displacements were carried out at strongly water-wet conditions and compared to moderately oil-wet conditions. For the oilfloods at strongly water-wet conditions, oil hydraulically filled the fractures from the top, while at moderately oil-wet conditions the oil crossed the fractures through what is thought to be capillary pressure contacts. This supports the earlier findings. For waterfloods the water hydraulically displaced the oil in the fracture bottom-up at SWW. At moderately oil-wet conditions, droplets of oil formed on the cross section, but no transport of oil was observed. The droplets formed capillary pressure contacts – yet strongly dependant on wettability. These experiments were later quality checked and validated, using numerical simulations.

In field development this observation could have the following implications;

- The rate of spontaneous imbibition varies with the capillary heterogeneities of the field.
- The injection rate into the different formations should be adapted to the different imbibition rates, to keep water cut development and overall liquid rate at a reasonable level.

In field development, from pre-project phase to late life evaluations of potential EOR projects, numerical simulations are instrumental tools to determine reserves and production profile. A dynamic model is supposed to give the most accurate image of a field potential at any give time. The means that at any given point in time, a dynamic will have to take into account all available static and dynamic information about the field.

- In place figures, oil column, PVT data, petrophysical measurements from cores and logs. Structural and sedimentological interpretations. RFT Pressures.
- Well test data and SCAL studies.
- Production history, 4D Seismic and other means of reservoir monitoring.

From the point of the first well test, we are at least partially able to validate the SCAL data obtained, by simulating the well test an matching the observed well test data with the numerical model.

This same type of exercise has been performed in this study. The capillary pressure and relative permeability data obtained as described in section 4.3, were used in as input in a numerical model built to represent the large scale block waterfloods. The pressure and production data, ultimate recovery, and finally the in-situ saturation development was used as “observed data” and the capillary pressure curves and relative permeabilities at different wettabilities were our matching parameters along with the implementation of more or less complicated fracture networks.

The overall best match between simulation and experiment was obtained with the capillary pressure curves in the model, and optimizing the relative permeability.

Once a sufficiently good history match has been obtained, the numerical model could be used for predictions. Results obtained from a predictive reservoir simulation can never completely replace the results obtained in experiments, but nevertheless it remains a very useful and effective tool to predict the potential impact from subtle changes in the input parameters.

Manipulations of the input capillary pressure curve for instance, gave useful information on the production mechanisms for each matrix block. It was also helpful when mapping the wettability distribution of the chalk blocks. Especially the shape of the positive part of the capillary pressure imbibition curve impacted the history match of the dynamic model. This was as expected because the shape of this curve and its endpoints determines the rate and ultimate recovery of the capillary imbibition process. The use of numerical simulations in general, and these latter specific observations are detailed in paper 5.

4.5 Measurement of capillary pressure

From the large block waterflood experiments and the numerical simulations, the capillary forces were identified as decisive for the production mechanisms in fractured carbonate reservoirs. A great part of this work has naturally been dedicated to the optimisation of capillary pressure curves;

- The spontaneous and forced imbibition capillary pressure curve has a great impact on production mechanisms and ultimate reserves in fractured carbonate reservoirs.
- The measurement of the positive part of the capillary pressure curve is technically difficult.
- Conventional measurement methods are time consuming, and dependent on mathematical correlations to convert average material balance saturation to in-situ saturation.
- Direct measurement of saturation methods are less time consuming and provide directly both parts of the imbibition capillary pressure curve by imaging of the in-situ saturation of the wetting phase.
- When this work was initiated DMS-methods were in the progress of being accepted as equally accurate as the conventional measurement methods.

A study comparing the direct measurement of saturation method with conventional centrifuge techniques, using carbonate core plugs at different wettabilities, was performed. The already validated techniques for wettability alteration were used when preparing the cores. As already mentioned the obtained capillary pressure curves showed consistent trend when moving towards less water wet conditions. The threshold pressure was lower and curvature indicated a porous medium homogenised by a consistent wettability change in pores contacted by crude oil.

DMS methods and conventional centrifuge methods proved comparable. The Pc-scanning curves obtained by the DMS method can be seen in Figure 12, Paper 6 and Figure 4.8.

Observations on primary and secondary Pc-drainage data:

- At strongly-water-wet conditions and at moderately-water-wet conditions at Iw=0.7, there were excellent agreement within the data.
- At Iw=0.4, the secondary capillary pressure drainage curve measured by the DMS method shows consistently higher Pc-values than those obtained by the conventional centrifuge method.
- PH-4 was the most water-wet plug among the plugs at I_w=0.4. However, we speculate that since the aging time for the plugs aged submerged in crude oil, exhibiting I_w=0.4, was as long as 30 days, these plugs may have a radial non-uniform wettability distribution and hence not be compatible to the wettability present in PH-4, even though the imbibition characteristics did not differ significantly.

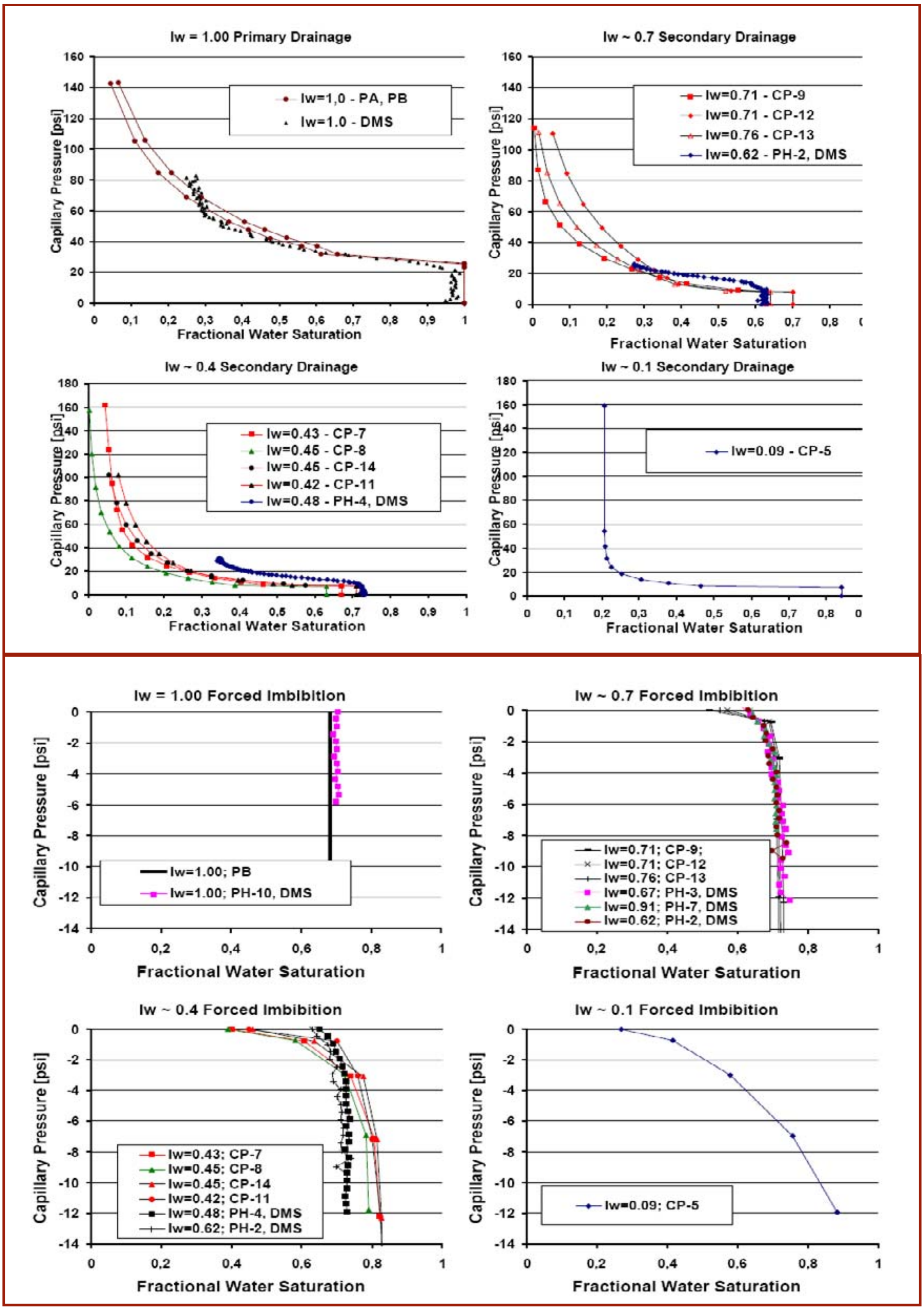


Figure 4.8 Comparison of DMS and Conventional centrifuge capillary pressure measurement.

Observations on forced water imbibition Pc-data:

- At strongly-water-wet conditions and at moderately-water-wet conditions of Iw=0.7, there are excellent agreement in the data except for the Pc=0 crossing point; the conventional method was obtained by counter current imbibition versus co-current imbibition for the DMS method.
- At Iw=0.4, the negative capillary pressure curve measured by the DMS method shows consistently lower Pc-values than those obtained by the conventional centrifuge method.

We speculate that this may be due to less representative wettability conditions for the core plugs included in the conventional centrifuge test. Another possibility is that the conventional method may be erroneous due to an inappropriate choice of a model to determine inlet face saturations. The trends observed for the forced imbibition is consistent with theory and previous observations.

Spontaneous imbibition Pc-data:

Figure 15 in paper 6 shows the positive part of the capillary pressure imbibition curve. For various wettabilities is illustrates the development of the capillary pressure during the spontaneous brine imbibition. For changes towards a less water-wet state the water saturation at capillary equilibrium (Pc=0), decreases, which is according to the fundamental understanding of this process.

The Pc=0 cross over point reflects the water saturation endpoint after co-current imbibition in the centrifuge measurements. It has been observed that there is a discrepancy between the endpoint after spontaneous imbibition depending on if the process has been counter-current, like in 3D-imbibition cells, or co-current, like in centrifuge measurements or 1D-imbibition experiments.

Also waterfloods at strongly-water-wet conditions, reflecting co-current oil production, shows higher water saturation endpoints compared to 3D-imbibition of strongly-water-wet core plugs. This observation is in accordance with findings reported by Cuiec et al. 1990.

From the very start of this work dedicated to capillary pressure and capillary heterogeneities, one of the objectives was to develop a new DMS-method at the University of Bergen, based on the nuclear tracer imaging technique that has been developed in this research group since mid 1980. An objective – or at least an ambition – for this method was to be able to do measurements at reservoir conditions using live crude oil.

An apparatus consisting of a Beckmann centrifuge with swinging bucket type core holders, capable of holding both reservoir pressure and temperature, and an imaging system similar to that of the large scale waterfloods, was constructed. This system would have the following advantages compared to existing DMS methods;

- Crude oil – live or dead - could potentially be used.
- Capillary end effects would be directly measurable.
- No assumptions are needed to calculate the capillary pressure since the local fluid saturations are directly measured at various capillary pressures.
- No need to solidify the oil phase, as in the MRI imaging techniques.

As presented in paper 7, the results of the feasibility study were encouraging. The saturation measurement showed strong dependence on collimator geometry and this should be further developed in the next phase of the development of this method.

Paper 7 describes in detail the calculations concerning the collimator geometry and also the theoretical assumptions on number of radioactive counts, as a function of radioactivity intensity, to pass through the collimator. Several factors have an impact on the quality of the measurements, the most significant include the collimator slit width and depth, the distance from the core to the collimator, the plug diameter, the activity of the tracer used to label the water phase, and the porosity of the rock material. The easiest to control is the collimator geometry, with the aim to have as high a resolution as possible (lower unit investigation element), but yet keeping the number of radioactive counts sufficiently high to have an acceptable uncertainty on the measurement. The plug diameter is largely dictated by convention and the maximum size that can be used in the centrifuge. The activity of the radioactive tracer was dictated by cost and safety, typically 1 to 2 mCi/l is acceptable. Porosity is dictated by the geology and morphology of the specific reservoir rock; for these samples it is in the order of 45%.

When the sample is spinning the detector will be exposed to the full diameter of the sample for varying length of time, which will complicate the calculation of absolute accumulated radioactive counts. This problem has been under continuous development throughout the study and also in the last years.

Before launching dynamic experiments, the reproducibility of saturation measurement was tested on static samples, using the 1D rig at the University of Bergen for quality control. Radioactive brine at 2mCi/l was used, and 100% scans were performed for 2 core samples. The two cores were then drained to 50% Sw and scanned using two different collimator widths, 0.2 and 0.4 mm, in which the 0.4 gave much better agreement. There is clearly a difference in reproducibility due to the difference in collimator slit width because of the poorer statistics for the narrower width. By increasing the collimator width the statistics of the measurements are improved at the expense of reduced longitudinal spatial resolution.

By increasing the counting time with the 2 mm collimator slit width an improved reproducibility would be obtained, but a limit for the data acquisition of about 24 hours eliminated this possibility for these preliminary experiments.

Another plug was drained to 80% Sw , then later 60% Sw, and imaged at both stages. Afterwards a test was performed to ensure that the in-situ saturation corresponded well to the average material balance saturation. See Figure 4.9:

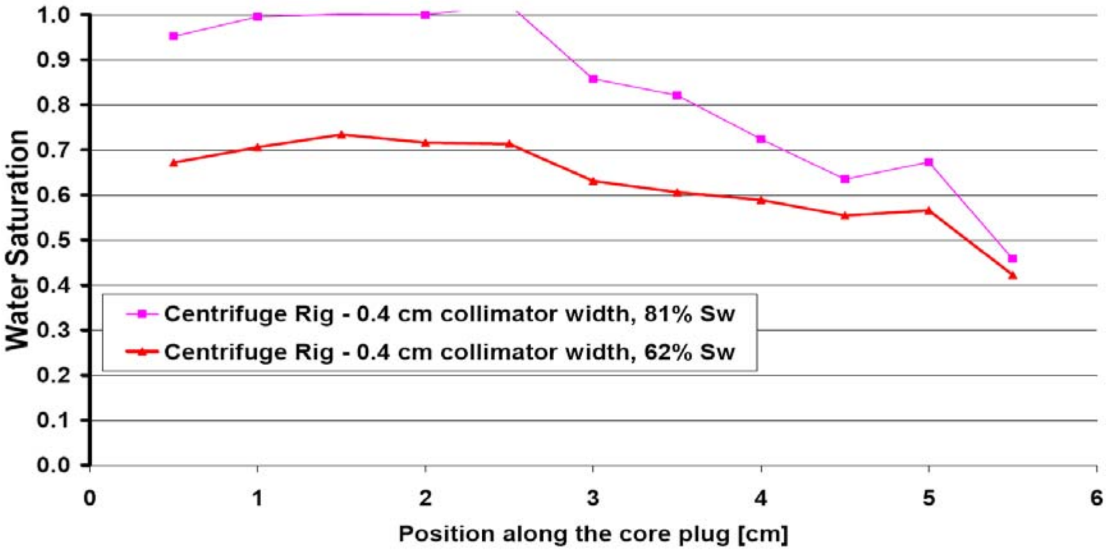


Figure 4.9 Generally good agreements between in-situ and material balance water saturation.

In addition to the good saturation agreement, the scanning method showed that the water and oil were not uniformly distributed along the longitudinal axis of the plug, information that can only be obtained by a method that determines saturation at specific spatial locations.

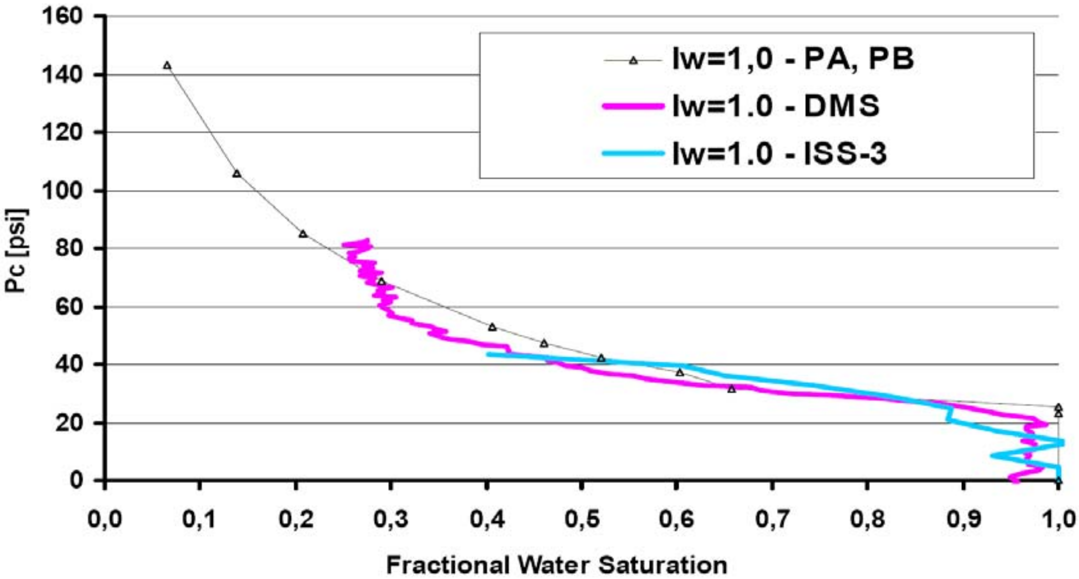


Figure 4.10 Good agreement of primary drainage curves between conventional, DMS and new method in spite of poor geometric resolution.

A preliminary primary drainage Pc-curve was also obtained from a third chalk plug. The results were compared to data for similar strongly-water-wet Portland chalk obtained by a conventional centrifuge method (Paper 1) and by the DMS-method (Paper 6). See Figure 4.10. Satisfactory results are obtained although the primary drainage curve for ISS-3 was obtained using an 8cm long collimator slit, which gave reduced spatial resolution of the saturation measurements, due to the curvature of the core trajectory.

The results are also less accurate due to the fact that a NaI-scintillation detector was used during this feasibility study, rather than a more expensive detector with higher energy resolution. This would increase the accuracies of the saturation measurements, since the background radiation then would have less impact on the results.

After the publication of Paper 7 in 2002, numerous improvements have been added to this experimental apparatus and increased understanding and optimisation of the imaging technique has been achieved.

The detector has been upgraded from a NaI detector to a Canberra Germanium Detector. The new detector has improved energy resolution. The collimator has been improved to fit the new detector.

In addition to the new collimator set up, a new gating device has been installed to minimize background radiation. The gating of the detector is trigged by a steel disc with a 40º opening installed at the bottom of the rotor in the centrifuge, and works together with a photo-diode to open and close the detector. The gating initiates the detector when the core is entering the measuring area (40º), and close the detector when the entire core is outside the measuring area. In this way background radiation is minimized, since the detector is closed when the core is not placed directly under the collimator opening when spinning.

The software to register the radioactive counts has been upgraded, making sure that the system – software – detector- gating system is capable of reading and registering signals at any possible centrifuge speed physically possible.

The theoretical approach to the tracer and saturation calculation has also been revised. A correction factor for differentiating between spinning and static imaging has been derived. The saturation calculations now also take into account the different energetic peaks of the Na-22 radioactive tracer.

Also, as the radius from the centre of rotation to each point on the core varies, the centrifugal acceleration will also vary. Necessarily the exposure time of each point along the axis of the core will also be different. Points closer to the centre of rotation will have smaller acceleration, thus exposed to the detector longer per rotation compared to the outer points. This will give artificially high water saturation at the inlet of the core, if this effect is not corrected for.
The coefficients are deduced by using the innermost point as a reference point, and normalize with respect to distance from rotational centre. See Figure 4.11. Each point

generates an angle, where alpha and beta is the maximum and minimum angle, respectively. Each angle relative to alpha is calculated, and serves as correction coefficients when comparing saturation profiles acquired with and without the centrifuge spinning.

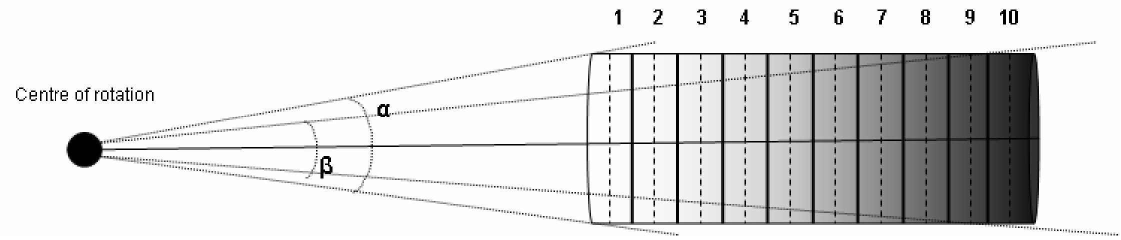


Figure 4.11 Calculation of correction coefficients where each angle from alpha and beta is calculated and the relative size is of each angle is standardized with respect to alpha.

Every experiment in this study has shown us the importance of fully understanding the production mechanisms of fractured carbonate reservoirs. One of many ways to achieve this is by performing experiments linking field observations to observations in laboratory experiments and SCAL studies. Here it is our mission as researchers to constantly develop more efficient and more accurate methods – by evaluating the methods already existing, and applying innovative techniques to improve them. From 50 years of modern petroleum industry history, fact is that laboratory experiments and the innovative fundamental research that goes along, is the first budget item removed when the price of a barrel falls.

5 – Conclusions and further work

5.1 Conclusions

7 scientific papers are published on a broad variety of subjects, and describes in detail the experiments and research treated in this thesis. Scientific research has been performed, investigating the subjects of capillary pressure and capillary heterogeneities from different angles.

This thesis discusses the findings in this study and aims to illustrate the benefits of the results obtained for further development of other experiments, and/or even the industrial benefits in field development.

The methods for wettability alteration have developed throughout the work. From producing heterogeneous wettability alterations, the methods have improved to giving both radial and lateral uniform wettability alterations, which also remains unaltered throughout the duration of the experimental work.

The alteration of wettability is dependent on initial water saturation, flow rate, aging time and crude oil composition.

Capillary pressure and relative permeability curves have been measured for core plugs at different wettabilities using conventional centrifuge methods. The trends observed are mostly consistent with theory.

The production mechanisms of strongly and moderately water wet chalk has been investigated. At strongly water wet conditions in fractured chalk; the flow is governed by capillary forces, showing strong impact from the fractures. At moderately water wet conditions, the impact of the fractures are absent, and a dispersed water front is observed during the displacement. The oil recovery is about the same, at the two wettabilities.

Fracture crossing mechanisms at the same wettability conditions have been mapped. And the observations are consistent with those of the water floods. During strongly water wet displacement, the fracture crossing is occurring once the inlet core has reached endpoint of spontaneous imbibition. At moderately water wet conditions the fracture crossing is less abrupt, and creation of wetting phase bridges is observed. The water may pass the capillary discontinuity before inlet core is at endpoint for spontaneous imbibition.

The observations of the water flood experiments have been validated using numerical simulators Eclipse and Sensor. Experimentally measured capillary pressure and relative permeability curves have been used to history match the observed production of the waterfloods. The observed variations in production mechanisms at wettability change are confirmed.

Direct measurement of saturation methods for measuring capillary pressure scanning curves have been investigated and compared to conventional centrifuge techniques. The same trends are observed for curves measured at different wettabilities, and the capillary pressure curves measured using DMS methods have also been validated in numerical simulations of type Eclipse and Sensor.

A feasibility study to develop a new method of measuring capillary pressure at various wettabilities has been performed with encouraging results. The conclusion is that the work should be further developed. The method has potential to enable capillary pressure measurements using live crude oil at reservoir conditions.

All in all, several experimental methods applicable in future SCAL synthesis have been presented. The observations are consistent and underline the production mechanisms of fractured chalk reservoirs, and will serve as inspiration in the future evaluations of tertiary oil recovery processes. An innovative approach to the measurement of capillary pressure is suggested.

5.2 Future work

Although the author's contribution is finished by this thesis, continued research is necessary to fully understand the impact of capillary pressure and capillary heterogeneities.

Concerning the new method for measuring capillary pressure, currently under development at the University of Bergen, some deficiencies will have to be corrected in the calculation of the collimation volumes. The following observations have been made during the feasibility study, and should serve as a map for improvements;

- The NaI detector should be replaced by a more recent state of the art, and accurate detector. It should have improved energy resolution, to increase the accuracy. (Reduced number of counts, but less impact from background radiation).
- New software for registration of the measurements should be installed. The new software should be able to gate the detector to open in sync with the rotations of the core sample.
- The collimator should be modified, with revised collimator volume calculations.

Waterflood experiments in fractured blocks at near neutral wet conditions should be performed following the model already developed, using the improved wettability alteration technique developed. The work could thereafter see if there would potential of moving into oil wet reservoirs, or even partially oil wet reservoirs.

Experiments could be improved by finding a way to measure the in-situ pressure gradients across fractures or across matrix blocks. This would provide interesting matching data for the numerical simulations. This had been tested before, by Viksund (1997) but showed to be challenging. However, as time goes by, the evolution of sealing materials could provide new possibilities.

Also the research group should look into more advanced history matching techniques for the waterflood experiments. Simulation software has made impressive developments in numerically assisted history matching. Mapping uncertain parameters like porosity, permeability fracture/matrix, capillary continuity across fractures, and distribution of wettability conditions, and then creating full factorial experimental design plans, one will obtain response surfaces for the different parameters. These response surfaces may be used to identify major impacting parameters in the history matching process, and furthermore improve the understanding of the impact of capillary heterogeneities.

As the worlds petroleum producing assets are declining and more and more fields are classified as "brown", improved oil recovery projects will become increasingly important.

Abbreviations

NFR	Norwegian Research Council
DMS	Direct Measurement of Saturation
SCA	Society of Core Analysts
USBM	United States Bureau of Mines
RDI	Relative displacement index
OOIP	Oil Originally In Place
PVT	Pressure Volume Temperature
SCAL	Special Core Analysis
NPV	Net Present Value
NMR	Nuclear Magnetic Resonance
MRI	Magnetic Resonance Imaging
NTI	Nuclear Tracer Imaging
PV	Pore volume
RPM	Rotations per minute
NaI	Sodium Iodine
Ge	Germanium
SWW	Strongly Water-Wet
MWW	Moderately Water-Wet
LWW	Less Water-Wet
MWL	Mixed Wet Large
MWS	Mixed Wet Small
EOR	Enhanced Oil Recovery
IOR	Increased Oil Recovery
WOC	Water oil contact
GOC	Gas oil contact
RFT	Repeat formation tester
FWL	Free Water Lever
IFT	Interfacial Tension

Nomenclature

Iw,o	Amott-Harvey Wettability Index to Water/Oil
Pc	capillary pressure
Sw	water saturation
Swi	initial water saturation
Sspw	water saturation after spontaneous imbibition of water
Sspo	water saturation after spontaneous imbibition of oil
Swf	water saturation after forced imbibition
Rwf	recovery by waterflooding
Kf/Km/k	absolute (f)racture and (m)atrix permeability
ϕf/ϕm	porosity (f)racture and (m)atrix
mD	milli Darcy
cP	centi Poise
Pi	pressure, i denoting phase (w)ater, (o)il or (g)as
Z	depth
Sor	residual oil saturation
Sorw	residual oil saturation relative to water
Sorg	residual oil saturation relative to gas
kri	relative permeability, i denoting phase (w)ater, (o)il or (g)as
D	radioactive counts, NTI
B	background radiation, NTI
F	uncertainty on saturation measurement using NTI
dP	delta pressure, differential pressure
θ	angle
ω	rotational velocity
μ	viscosity
σ	surface tension

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PART 3 – SCIENTIFIC PAPERS

Part 3: Scientific Papers

Paper 1
Graue, A., **Bognø, T**., Moe, R.W., Baldwin, B.A., Spinler**,** E.A., Maloney, D., Tobola, D.P.: "Impacts of Wettability on Capillary Pressure and Relative Permeability", SCA9907, Reviewed Proc.: 1999 International Symposium of Core Analysts, Golden, Co., USA, Aug. 1-4, 1999.

Paper 2
Graue, A., Aspenes, E., **Bognø, T**., Moe, R.W., Ramsdal, J.: "Alteration of Wettability and Wettability Heterogeneity", J. Petr. Sci. & Eng. 33 (3-17), 2002.

Paper 3
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Paper 4
Graue, A., Aspenes, E., Moe, R.W., **Bognø, T**., Baldwin, B.A., Moradi, A., Tobola, D.P.: "Oil Recovery Mechanisms in Fractured Reservoirs at Various Wettabilities Visualized by Nuclear Tracer Imaging and NMR Tomography", Rev. Proc.: 22nd Annual Workshop & Symposium Collaborative Project on Enhanced Oil Recovery International Energy Agency, Sept. 9-12, Vienna, Austria, 2001.

Paper 5
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Paper 6
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Paper 7
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