WETTABILITY EFFECTS ON OIL RECOVERY MECHANISMS IN FRACTURED CHALK

by

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Summary

This thesis is a part of the ongoing project, “Oil recovery from fractured chalk reservoirs”, which is a collaboration between the Reservoir Physics Group at the University of Bergen and ConocoPhillips Research Center in Bartlesville, Oklahoma. The project was initiated in 1990 and for the last 15 years about 30 Master and PhD candidates have graduated and, mainly employed by the oil industry. Dedicated candidates combined with professional guidance and stable funding has been a key to the success of this long term research project.

Early work in this project report experiments on large chalk blocks subjected to water floods. The dynamics of the water front propagation during water floods were monitored by nuclear tracer imaging for homogeneous whole blocks and when fractured. The impact of the fractures on the water flood could then be investigated. Emphasis was on the effect of wettability condition on the recovery mechanism. In addition to the saturation monitoring system, attempts to measure the pressure difference across different fractures in the block were made with varying degree of success.

Based on the findings of the earlier work, emphasis for further research as a part of this thesis work was chosen:

1. Improve the aging technique to obtain reproducible, uniform and relevant wettabilities
2. Improve imaging in order to study the details on fluid transfer across open fractures at different wettability conditions.

The results of this study are reported in six papers; denoted paper 1-6. Based on experiments reported in **Paper 1,** an improved aging method was developed. It yields faster and more consistent response to the aging. In addition, one of the main motivations for developing a new aging method was the problems with radial wettability heterogeneities as an artifact of the former aging method, Spinler et al. 1999. Control of the wettability distribution within the rock material is significant when investigating in detail the recovery mechanisms as function of wettability. It also would be an advantage if the new aging method was applicable on core plugs as well as for large block systems.

Wettability heterogeneity will have impact on several types of core sample tests like measuring capillary pressure, relative permeability, spontaneous imbibition, centrifuge residual oil or residual water measurements and other measurements like NMR T_2 distribution for bound water and fluid saturation calculations.

Several aging methods were compared. Results show that flushing crude oil at low Darcy velocity through the core plugs while aging are significantly more effective comparing to the submerged or the static aging procedures. This can be explained by the constant supply of active aging components to the mineral surface during flushing. However, possible absorption of active components may result in reduced wettabilibty alteration downstream. In order to demonstrate this, a stack of five core plugs (a total of 24cm) were continuously flooded with crude oil from one end. After aging, Amott tests were performed on each separate core plug in order to determine the effect of the aging. Nuclear tracer imaging provided in-situ saturation information. Results reveal significant absorption of the active aging components near the inlet end and no aging effect at the outlet end of the stacked system. Furthermore experiments on alternately flushing from both ends were performed on a slightly shorter core plug (16cm). By utilizing NTI for internal saturation measurements during the Amott test a resolution of 1cm in wettability distribution measurement along the flood direction of the core plug was obtained. Uniform wettability was measured throughout

the length of the core sample except from a dip towards lower wettability conditions at the ends (1-2cm).

Further development of the new aging method is reported in **Paper 2**. The stability of the induced wettability condition was validated through several tests like storing, flooding, drying or solvent injection. MRI was utilized to provide saturation distribution at sub millimeter resolution during the Amott tests, thus detailed 2-dimensional information on wettability distribution was obtained. Although the overall results of the new aging method show significantly more uniform distribution of the induced wettability, the method revealed a small dip in wettability towards less water wet conditions near the end face of the core plug representing inlet during the primary crude oil drainage. The 2-dimensional MRI saturation data also made it possible to calculate radial effects as well. It turned out that the new developed aging technique yielded uniform radial wettability alteration.

A stacked core plug system with a fracture plane normal to the flow direction was used to obtain further understanding of the recovery mechanisms. MRI images with sub-millimeter resolution revealed the recovery mechanisms when performing water floods at different wettability conditions. The experiments reported in **Paper 3** was a feasibility study attempting to visualize the actual wetting phase transport mechanism across open transverse fractures. The improved aging technique described above was utilized to produce stacked core systems yielding a selection of wettability conditions. The open fracture was 1mm in aperture.

At strongly water wet conditions, a water hold-up due to the capillary end effect was observed in the matrix before water entered the fracture. The water segregated as a thin film along the outlet end surface of the first core plug before filling the fracture and starting imbibing into the next.

At less water-wet conditions, water started forming droplets on the outlet face of the first core plug rather than a thin film. This happened earlier than the film flow seen in the strongly water wet system, suggesting lower water saturation in the first core before entering the fracture. The droplets grew in size until contact with the surface of the next core sample was established providing a continuous water phase from one matrix block into the next matrix block. The bridges of water were established across the fracture resulting in a dispersed water front entering the adjacent matrix block as if the fracture was not present.

In **Paper 4** brings the work on recovery mechanisms presented **Paper 3**, a step further. To secure equal wettability conditions at each side of the open fracture single core plugs were aged multi directionally and then cut into two shorter plugs used as the stacked system. By using improved signal to noise ratio for the MRI signals better images was obtained than in the previous study. The MRI imaging was expanded to include the in-situ dynamic saturation development along the long axis of the core plugs. This gave us information on longitudinal water front movement and the saturation when the wetting phase entered the fracture could be calculated. Core systems yielding Amott wettability index to water of approximately 1.0, 0.6 and 0.3 reflects a variety of wettability conditions from strongly water wet to near neutral wet. Differential pressure across the stacked core system was logged. The pressure data transients are difficult to interpret, however the main trend indicated some difference between the I_w=0.6 and the I_w=0.3 system.

Paper 5 is a conclusive paper on the work performed by the Reservoir Physics Group at the University of Bergen and combines results from fracture crossing experiments with the parallel work on large fractured blocks performed by other candidates in the research group at the University of Bergen. The knowledge on capillary contact across open fractures at different wettability conditions from **Paper 3** and **4** was used to implement various capillary contacts in the numerical simulators significantly improving the in-situ water movement history match.

In **Paper 6** the concept of capillary contact across open fractures is subjected to further investigation. Experiments were performed on a core plug with a fractured system containing isolated blocks. The results corroborate the suggested theory describing how wetting phase bridges across open fractures add a viscous component to the recovery on such an isolated matrix block. The water bridges were stable for days and resulted in oil recovery far exceeding the spontaneous imbibition potential. Hence an oilfield with moderately to nearly neutral wet conditions may respond very well to water injection. This has been seen in the Ekofisk field in the North Sea where the moderately water-wet (MWW) and the strongly water-wet (SWW) zones of the reservoir both responds well to the water flood recovery strategy.

Main conclusions drawn from this thesis work is that by subjecting low permeable chalk to wettability alteration by multi directional flow of crude oil, rather than static aging by submersion in crude oil, significantly more uniform wettability distributions are established.

When subjecting MWW fractured low permeable chalk to oil recovery by water flooding, capillary continuity by water bridges may be established across the open fractures adding a viscous component to the oil recovery. This will give significant contributions to the oil recovery from isolated blocks.

PART 1: FRACTURED CHALK RESERVOIRS

PART 2: WORK & DISCUSSION

PART 3: PAPERS

Paper 1: "Alteration of Wettability and Wettability Heterogeneity"

Paper 2: "In-Situ Wettability Distribution and Wetting Stability in Outcrop Chalk Aged in Crude Oil"

Paper 3: "MRI Tomography of Saturation Development in Fractures During Waterfloods at Various Wettability Conditions"

Paper 4: "Fluid Flow in Fractures Visualized by MRI During Waterfloods at Various Wettability Conditions – Emphasis on Fracture Width and Flow Rate"

Paper 5: "Complementary Imaging Techniques Applying NTI and MRI Determined Wettability Effects on Oil Recovery Mechanisms in Fractured Reservoirs"

Paper 6: "Wetting Phase Bridges Establish Capillary Continuity Across Open Fractures And Increase Oil Recovery In Mixed-Wet Fractured Chalk"

Part 1

Fractured Chalk Reservoirs

Chapter 1: Literature Survey

1.1 Introduction

When oil displacement by water injection became a commercial secondary recovery method in the early 1950's the understanding of the fractured reservoir response to this process became important. Spontaneous imbibition of water into the oil bearing matrix was the overall explanation of oil production exceeding the oil volume expected from the fracture network.

Counter current imbibition was assumed between the oil bearing matrix and the water-supplying fracture network. In water/oil displacement, block to block interaction was neglected and all fluid transport was assigned to the fracture infrastructure. This is referred to as "single porosity" models and was the beginning of the modern numerical simulation of fractured reservoirs.

A representative single porosity reservoir model would require dividing the matrix and the fractures into small grid blocks. The discretization of an entire reservoir would have to be a compromise between details and the computing time. Detailed models contain large number of cells and the small volume of each cell requires smaller time steps. A courser grid model will compute faster, but may suffer from lack of important details.

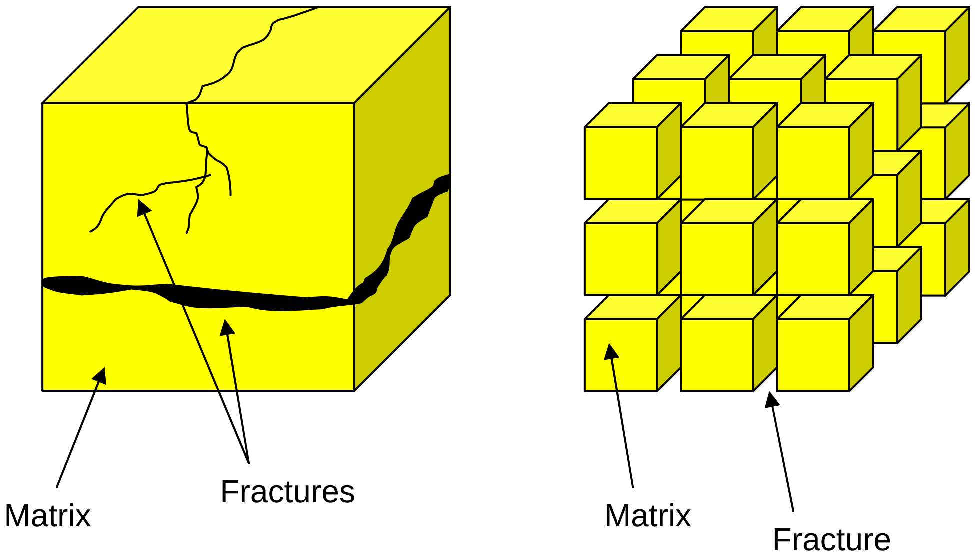


Figure 1.1: Ideal dual porosity representation of fractured porous rock (Warren and Root, 1963)

In 1963 Warren and Root approximated fractured reservoirs by an orthogonal array of matrix blocks surrounded by fractures as illustrated in Figure 1.1. To avoid the compromise on single porosity models, an alternate numerical simulation technique was developed. This technique involves discretizising the reservoir into two subsets of grid blocks. One subset is representing the matrix blocks while the other subset represents the fracture network. The flow of fluids between the matrix and the fractures is approximated by a matrix-fracture transfer function which depends on the saturation, permeability, wettability conditions and the volume/surface area ratio of the matrix block among other. This technique is called "dual porosity" and is the most common method used for simulating fractured reservoirs. In 1976 Kazemi published the first report on a three-dimensional, compressible, water-oil reservoir simulator which was applied on a reservoir as a whole.

The dual porosity numerical simulators have through the years been improved to yield more realistic results, and an important part of the development process was to perform experimental work in order to describe the physics to be implemented. Numerous papers and thesis are found in the literature on fractured reservoirs, however only a minor part reports experimental work. The following is a short review of publications within several main subjects of interest, including experimental investigation of the **transfer function** between matrix and fracture, **flow functions** of the fracture i.e. relative permeability and capillary pressure, effects on **gravity drainage** including re-imbibition, **capillary contact** and gravity segregation in vertical fractures and last but not least experiments on **wettability alteration** because the wettability of the porous media is known to control at the processes mentioned above.

1.2 The Transfer Function

In the case of the transfer function between the matrix and the fracture, Mattax and Kyte presented in 1962 an experimentally determined imbibition function, describing the capillary driven matrix-fracture counter current imbibition. They found that oil recovery from the matrix as function of time was dependant on the water injection rate and the size of each individual matrix block. The latter was used for up-scaling purposes.

Barenblatt presented in 1964 the transfer of oil into the fracture by simply applying Darcy's law assuming the reservoir pressure depletion to occur in the high permeability fracture network. This creates a pressure gradient from the matrix blocks towards the fracture network.

In 1972 Mannon and Chilingar reported experimental work on one-dimensional imbibition from an adjacent open fracture. From the matrix surface exposed to the open fracture, water imbibed into the matrix blocks and the oil expelled was produced downstream in the fracture network along with the water. They found that the matrix-fracture transfer flow increased with increasing fracture flow rate, temperature and fracture roughness. In this experiment matrix saturation was calculated from material balance.

Kleppe and Morse (1974) took a step further in the experimental work on matrix-fracture fluid transfer. They injected water in a system consisting of a large vertical oriented core sample (4 inch diameter and 4 feet high) placed in a tube, defining the space between the tube and the core as the fracture. Oil and water saturation was determined by means of resistivity measurements several places along the height of the core. Initial water saturation was established and capillary pressure and relative permeability functions were measured on smaller samples using conventional methods. With this amount of detailed information it was possible to simulate the behavior of the system with good agreement. The main conclusion was oil recovery being dependant on the production rate and the fracture-matrix flow capacity ratio.

In contradiction to the results found by Mannon and Chilingar, Babadagli performed, in 1994, experiments showing that the matrix fracture transfer rate increased with decreasing fracture flow rate over a certain critical limit. The water flood experiments were performed on core samples cut into halves in the cylindrical direction, with the cut representing the fracture. CT-scanning provided dynamic saturation information during the water floods. They concluded that at low flow rates the oil recovery from this fractured system behaved similar to a homogenous system. When increasing the injection rate one would reach a critical rate where further increase would result in inefficient capillary imbibition transfer. The critical rate was defined as a function of maximum matrix capillary pressure and matrix permeability.

Babadagli also includes the effect of variations in wettability in one of his publications, Babadagli and Ersahagli (1992). By water flooding artificially fractured core samples which had been subjected to chemical treatment, it was concluded that wettability conditions other than SWW has an increased induction time and hence a higher water/oil ratio in the early phase of the production from the reservoir. The total oil recovery seemed to remain unchanged.

The effect of wettability on the transfer function was further investigated by Putra et al. (1999). Water floods on hydraulic fractured core samples showed that the critical rate, defined by Mannon and Chillingar, was highly dependant on the wettability of the matrix. Weak capillary forces could be the major controlling factor lowering the critical rate below the limit of profitability of such an oil field.

In 1995 Miller and Sepehrnoori performed simulations on the experimental results on one dimensional cocurrent imbibition experiment presented by Kleppe and Morse. They found that during dynamic fracture flow conditions, the matrix fracture transfer function could be divided into three flow periods: before breakthrough, infinite-acting and late flow. They also defined two parameters controlling the process, global time scale ratio N_t and the storativity ratio ω. N_t takes into account the time ratio between residence time in the matrix and the fracture, and the storativity ratio ω defines the ratio of storage capacity between the fractures and the entire system.

An experimental setup with a combination of transverse and elongated fractures was subjected to water floods at several different wettability conditions, Tang and Firoozabadi (2000). It was shown that in the cases of weakly water wet conditions, the applied pressure gradient across the system substantially controlled the recovery. However, the unrealistic pressure gradient of 3psi/foot and the corresponding rate of 23PV/day they used in their experiments may yield overestimated recovery compared to field cases. This is the opposite of what Gurpinar and Kossack, (2000) found from their numerical simulations. They stated that the forced imbibition part of the capillary pressure curve does not affect their simulation results.

1.3 Flow Functions in Fractures

It is generally assumed for open fractures that the relative permeability functions of each phase are equal to its saturation (straight line relative permeability curves). This assumption is based on the experimental work of Romm presented in 1966. The experiment was performed on a horizontal stack of glass plates with waxed paper stripes in between, the void space being the pore volume. The way this two dimensional medium was made, it did not allow for gravitational segregation. Romm's results are still widely used today despite indications that they may not be a good representation of fluid behavior in open fractures.

Maloney and Doggett (1997) performed steady state relative permeability measurements on both wide (800μm) and narrow (50μm) fractures represented by the open space between the two elongated halves of a sandstone core sample. The fracture aperture and saturation in the vertically mounted system was monitored by 2 dimensional X-ray apparatus. The results from the narrow fracture experiment support the straight line relative permeability curves proposed by Romm. However in wide fractures, gravity segregation seemed to dominate the flow functions. Upward and downward direction of flow yielded different flow regimes.

Several unsteady state fracture relative permeability experiments on fractured core samples and artificial materials are reported where straight line relative permeability curves are not obtained, Merrill (1975) and Pieters and Graves (1994). Similar observations are reported by Pan and Wong (2000) in a smooth artificial fracture.

Fourar and Lenormand (1998) performed air/water permeability measurements on an elongated fracture represented by two glass plates separated by 1mm open space. Saturation was determined by weight measurement of the system. Several fluid flow configurations were identified in the artificial fracture: bubbles, unstable bubbles and film flow. As a consequence of these observations, it was stated that any physical model should account for the viscous coupling between the two fluids flowing simultaneously, and the sum of the relative permeabilities should always be less than 1. They presented an analytical relationship based on calculation of viscous coupling of the two fluids.

Another way to experimentally determine the fracture relative permeability is reported by Babadagli and Ershaghi (1994) and Akin (2001). By history matching water floods of fractured core plugs, fracture relative permeability is obtained from optimizing the input parameters. The problem with this method is the need of capillary pressure in the fracture. Strong dependency on fracture flow rate, matrix capillary pressure and matrix permeability was reported.

By representing both the fracture and the matrix relative permeabilities in one single pseudo permeability function, the heterogeneous media can be represented by larger homogeneous volumes (up-scaling). Hence the dual porosity model can be simplified into a fracture network representation, Babadagli and Ershagi (1993). In fracture network simulations of core floods, pseudo relative permeability behaves like fracture relative permeability when fracture flow is high compared to matrix and vise versa.

1.4 Gravity Drainage and Capillary Contact

The concept of gravity drainage was first presented by Cardwell and Parsons (1948). When hydrostatic pressure between the non wetting phase in the fracture and the wetting phase in the matrix blocks overcomes the capillary forces, drainage will start to occur from the top of the matrix blocks (Figure 1.2) the oil recovery by the gravity drainage process in a fractured reservoir strongly depends on the height of reservoir rock in vertical capillary continuity. Only a limited number of experiments are reported.

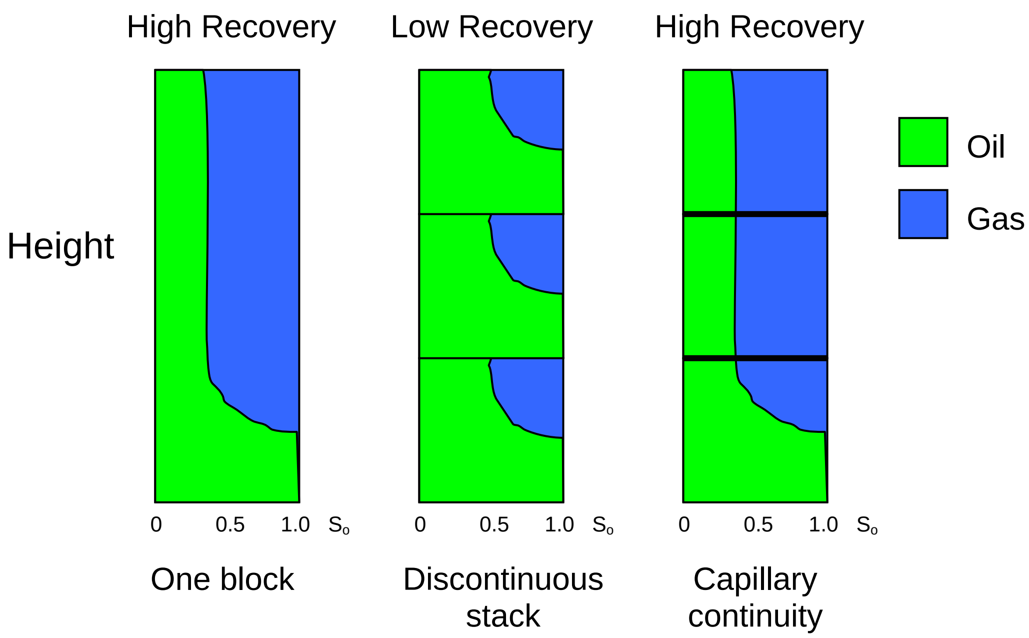


Figure 1.2: Effect of capillary contact between vertically stacked matrix blocks during gravity drainage.

Experiments by Saidi et al. (1979) questioned the single-block concept used in the numerical simulations of fractured reservoirs. They argued that wetting phase flow out of one matrix block should re-imbibe onto the next lower one rather than flow along the fractures. They suggested that interaction of matrix blocks occurred due to wetting phase liquid bridges across the horizontal fractures.

Horie et al. (1990) performed capillary drainage experiment on a vertical stack of three Berea core samples with a total height of 90cm. Each of the three core samples had a height corresponding to the capillary threshold pressure with the fluids present. Saturation was obtained from material balance. By repeating the experiment only changing the fracture representation, the oil production as function of time was used as an indicator for the degree of capillary contact. No capillary contact was observed with a 0.3mm open fracture while increased capillary contact was observed when experiments were run with subsequent decreasing grain size was used as fracture fill material. Good capillary contact was observed when the stack of cores was forced together with no spacing other than the voids resulting from the roughness of the adjacent core plug surfaces. The capillary contact observed when using sand grains in the fracture was assumed to consist of liquid “bridges” along the surface of grains in the fracture.

Firozabadi and Hauge (1990) extended the work of Hoire by proposing fracture face modeled as cones, each of which contacts the tip of a cone from the opposing face. In this model both the physical contact points and the roughness of the surface of natural fractures are included. Stacked cores were spun in a centrifuge and production data was history matched. The capillary pressure in the fracture was calculated from the cone model.

The same year Labastie performed similar experiments. The fracture was represented by porous media of different permeabilities. They concluded that in most cases, the capillary continuity existed. The permeability of the fracture was controlling the production rate, but total recovery was not affected.

Fung (1990) improved the dual porosity model for numerical simulation by accounting for the reimbibition process and allowed for matrix-matrix interactions to occur in the vertical direction.

Stones et al. (1992) performed gravity drainage on stacks of sandstone core samples using Compute Assisted Tomography (CAT) scanning for matrix saturation distribution. It was stated that the total effective area of the liquid bridges across the fracture controlled the production rate. As a consequence of the latter, they reduced surface tension by adding surfactants to the wetting phase and thereby increased the bridging flow area.

A recent publication presented by Sajadian et al. investigates the capillary contact as function of fracture aperture. Stacked sandstone samples separated by an artificial fracture were subjected to gravity drainage. Supported by previous publications, they indicated the existence of liquid bridges from the production rate. High production rate indicates liquid bridges and vice versa. By subsequently repeating the experiment, each time with an increased fracture aperture they were able to find a threshold aperture t_{fc}, above which no liquid bridges were formed. They stated that in cases of fracture aperture below t_{fc} a growing hanging droplet at the bottom face of the top core plug will touch the bottom plug and deform into a stable liquid bridge. Above t_{fc}, the deformation of the hanging droplet will cause it to snap off.

1.5 Wettability Alteration

Acid/base interactions, asphaltene precipitation, ion binding and polar interactions represent some of the mechanisms by which the crude oil components may alter the wetting properties of a rock surface, Buckley et al. (1998). Early work suggests that the wetting properties of a reservoir rock are due to presence or absence of polar organic compounds in crude oil, Benner and Bartell (1941). Experiments on wettability alteration of a porous media by adsorption of polar compounds have been performed by several authors, and a detailed summary by Anderson was published in 1986.

Glampietro et al. (1996) in their comparative study of static vs. dynamic adsorption onto formation rock showed that the dynamic asphaltene adsorption is a continuous phenomenon by which the quantity of adsorbed asphaltene increases as a function of the asphaltene-solution flowing time.

Wettability alteration with systematic changes in oil composition was evaluated by Buckley et al. (1997), using contact angle measurements, concluding that crude oils generally induce greater alteration as they become poorer asphaltene solvents.

Liu and Buckley (1997) investigated the interaction that occurs after initial oil/solid contact. The wettability alteration was determined by measurement of the contact angle between pure fluids after removal of bulk crude oil. They found that adsorption of crude oil components onto dry glass surfaces was not strongly time dependant while it was strongly time dependant on prewetted surfaces.

Skauge et al. (1995) characterized twelve crude oils derived from the North-Sea with respect to asphaltene content, composition of saturates, resins and aromatics by the use of thin-layer liquid chromatography. Based on different acid and base content the oils were selected for adhesion and contact angle experiments using a sessile drop technique on quartz surfaces as a function of pH. The results showed that the effect of aging was poor at high acid number, and better at higher base number. However acid and base number did not correlate with asphaltene content.

In 1999, Spinler in collaboration with the University of Bergen looked at capillary pressure curves in several locations along a core plug utilizing a new centrifuge technique using MRI imaging at static conditions. They demonstrated that in low permeable rock the outer circumference of a core plug subjected to aging by submersion in crude oil at elevated temperature responded well to the alteration while the central part of the core plug remained unaltered.

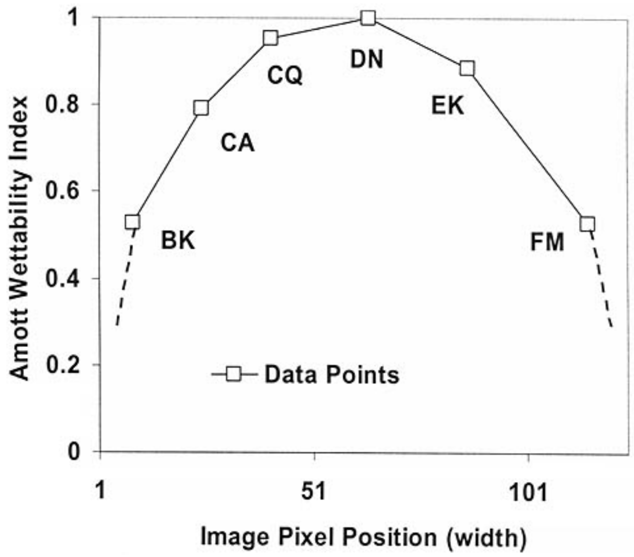


Figure 1.3: Wettability as function of core diameter (Spinler et al. 1999).

Buckley and Wang (2002) added that acid or base number alone were not sufficient of describing wetting behavior. They stated that the acid-to-base ratio in addition to the acid and base number was necessary.

The importance of acid and base content in the oil phase, which is related to polar and ionic interactions between oil components and charged mineral surfaces, was demonstrated by Torsæter (1997) through core experiments where a water wet Berea core was subjected to aging by n-decane added base altered the core sample into neutral wet conditions.

Jadhunandan and Morrow (1991) performed aging experiments on core plugs where two crude oils of different asphaltene content were introduced at residual water saturation. They stated that alteration capability of a crude oil is not dependant on the asphaltene content but rather on the total amount of asphaltene removal from the crude oil.

Experiments performed with simple organic acids dissolved in non-polar oil showed that the wettability of the carbonate could be changed from strongly water wet to moderate water wet without asphaltenic content in the oil, Neumann (1966).

Høiland et al. (2001) performed sessile drop experiments on water covered glass plates. North Sea acid extracts diluted with toluene represented the oil phase. Contact angle measurements showed that the pH of the oil phase had major impact on the electrostatic repulsion controlling the wettability.

It has been found that transition metal ions can affect wetting on high energy surfaces, Morrow et al. (1984).

A decrease in temperature or pressure is a possible trigger for asphaltene flocculation and precipitation which can lead to a less water-wet state, Hirasaki (1991). This is one possible explanation of how wettability might change during oil production.

When it comes to measurement of changes in wettability the Amott-test (Amott, 1959) is by far the preferred method. However both in field and in laboratory applications the method has weaknesses when it comes to uncertainty in initial water saturation, the use of oil based drilling mud, the lack of sensitivity near neutral wettability, wettability heterogeneities, mixed vs fractional wettability and test temperature and pressure. Recently Al-Mahrooqi et al. (2005) presented a study using a combined wettability measurement through shift in NMR T_2 relaxation times and changes in electrical impedance. This method has the ability to measure changes in wettability as the experiment is ongoing and hence has the ability to investigate direct effect of changes in temperature and pressure. In addition the method clearly indicated the mixed wet large (MWL) phenomenon.

Another recent development in wettability measurement is presented by Strand et al. (2004). Thiocyanate, SCN^-, and sulphate SO_4^{2-} in water are injected into the core sample. SCN^- used as a tracer is inert to the carbonate rock and will be produced along with the water. However the SO_4^{2-} will adsorb to the water-wet sites of the carbonate rock. Chromatography of the effluents shows the separation in concentration of the SCN- and the SO_4^{2-}. The area between the curves is directly proportional to the water-wet surface area inside the core. Experiments utilizing this method show that an area of 60% has to be water-wet for spontaneous imbibition to occur. Note that this method works for carbonate rock only.

Another way to alter the wettability in a carbonate core is to treat it with acids in dry state, and saturate the core after the treatment, Sweeney and Jennings (1960). However this will render all pores equally oil-wet and thus does in many cases not represent the real reservoir wetting conditions.

A study on wettability reversal from oil-wet to more water-wet applied various concentrations of a single surfactant in pure fluids, Owens and Archer (1971). These methods are utilized in Enhanced Oil Recovery (EOR) investigations where animes are used to produce an alkaline water flood. This is interesting in cases of water flooding in fractured oil-wet low permeable reservoirs, increasing the spontaneous imbibition potential, Johnson (1976).

An increasing number of oil-wet fractured low permeable carbonate reservoirs are now in the phase of tail production. Hence high focus has been on finding cheap surfactants used for reversal wettability alteration. Authors like Hirasaki, Torsæter and Austad are presenting different surfactants showing promising results on laboratory scale, however little experience from field data is published. In the theory the negatively charged surfactants will adsorb onto the positively charged chalk surface and release the polar active aging components. However chalk has a surface area of 2-3000m^2/kg of reservoir rock (Austad, 2005) and a high surfactant concentration is therefore needed in the injection water. In addition some of the surfactants suggested have unwanted bi-effects with regards to scale precipitation or environmental aspects.

A numerical simulator has been modified by Adibhatla et al. (2005) to include the change the flow functions and interfacial tension (IFT) as wettability changes from oil-wet to water-wet during surfactant injection. The surfactants are entering the matrix blocks by diffusion from the injection water in the fractures and the wettability changes gradually as the concentration of the surfactant increases. Laboratory experiments showing promising results are used for calibrating the new method. Results from large scale simulations show that surfactant distribution (diffusion velocity) is the limiting factor.

Chapter 2: Towards Understanding Wettability Effects on Water Floods in Fractured Chalk Reservoirs

2.1: Summary of Project at UoB

The Reservoir physics group at University of Bergen was founded in 1983. The knowledge within nuclear physics was used when applying the methods developed by Bailey et al. using nuclear tracers in fluids and hence visualizing fluid flow through porous media. The technique was soon expanded to investigate gravity drainage and later 2-dimensional dynamic fluid saturation “images” of fluid flow in larger porous media systems with simultaneous impact of capillary, viscous and gravitational forces. This technique had great advantages when it comes to visualizing fluid dynamics of heterogeneous porous media. The last ten years the emphasis has been on fractured chalk models.

In 1995 a number of outcrop chalks were investigated and compared with rock samples from upper Ekofisk area, Lie (1995). Petrophysical parameters like porosity, absolute permeability, capillary pressure curves, wettability, water production during drainage, irreducible water saturation, pore size distribution and end point relative permeability to oil were measured. In addition, thin section samples were studied to gather information on mineralogy and diagenesis. The scope of this work was to find the best outcrop analog to the oil field under study. Outcrop is used because of the limited access to core material from the actual reservoir. In addition, the size of the rock samples from drilling is limited by the size of the sample drilling tool, typically a diameter of 4-6 inches. Drilling tends to degrade the core material through injection of drilling mud, pressure depletion and internal fracturing. One of the main conclusions of the outcrop screening was that Rørdal chalk from Ålborg in Denmark was an excellent analogue to the upper Ekofisk formations.

In 1996 water floods were performed on a stack of three core plugs in a Hassler cell, Figure 2.1. Nuclear tracers in the water phase allowed a movable detector to image the dynamics of the water front propagation through the fractured system. Neither the Nuclear Tracer Imaging (NTI) technique nor the production data indicated any effects of the fractures. A combination of the smooth machined end surfaces of the core plug used and the high axial pressure of about 1bar in the Hassler Cell caused the stacked system to obtain good capillary contact across the fractures and hence the stacked system behaved like a continuous medium.

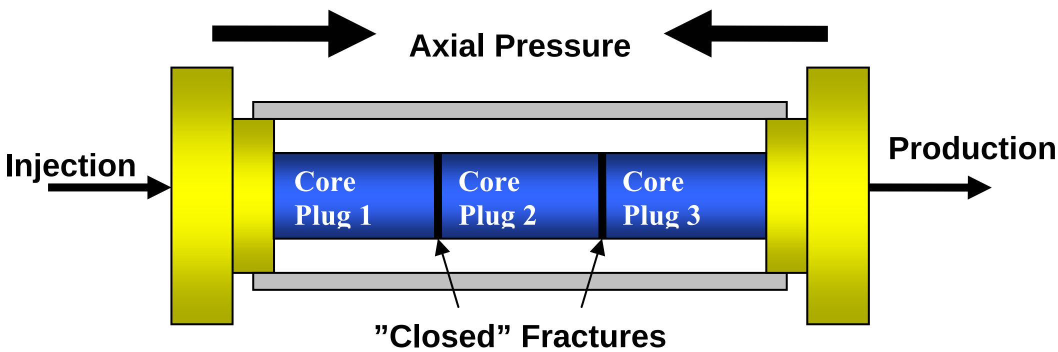


Figure 2.1: Schematics of Stacked Core Experiment in Hassler Cell

In the continuation of the project, the Reservoir Physics group at UoB started to look at the impact of fractures on two phase fluid flow in larger blocks (approximately 20x10x5cm). Nuclear tracer imaging was utilized to image the fluid flow dynamics in two dimensions. The imaging technique was first used to show the 2-D dynamics when water flooding a non-fractured block. Then the water flood was repeated with a known fracture network. Comparing the two water floods showed that the fractures had minor effect on oil recovery but had major impact on the local in-situ water movement. Both an open fracture (2mm aperture) and closed fractures seemed to impede water flow from the matrix to the fracture until the end point of spontaneous imbibition was reached. In comparison to the experiment on a stack of core plugs in a Hassler cell previously described, the assembly pressure applied on the large blocks was much lower. In addition the coarse fracture surface obtained using a band saw was believed to reduce the capillary contact across the fractures. The high initial water saturation (not representative for upper Ekofisk) caused a dispersed water front.

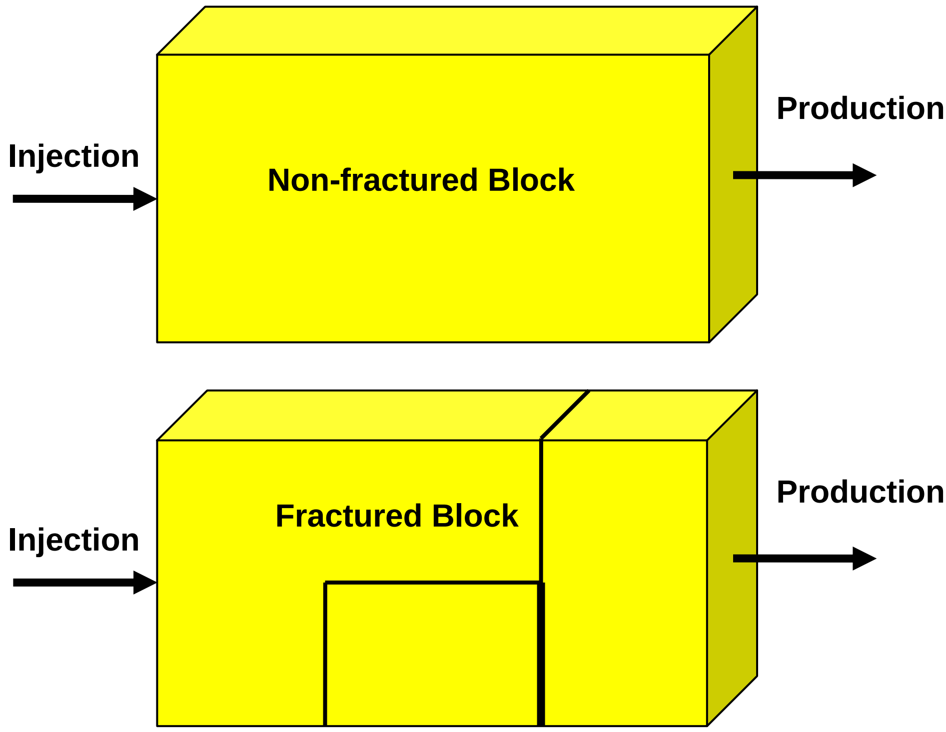


Figure 2.2: Schematic showing Fractured and non-fractured block experiment.

Later in 1997 the first water flood at moderately water wet conditions was performed in order to make the wettability more comparable with the upper Ekofisk reservoir conditions. The wetting properties of this strongly water wet outcrop rock had to be permanently altered. At elevated temperature the samples were drained to initial water saturation and thereby subjected to crude oil for a chosen exposure time. Then the crude oil was displaced by mineral oil. The initial water saturation was chosen to be 20-25%PV as a compromise between average initial water saturation at upper Ekofisk and the pressure limit for the large block equipment. Only smaller changes in the oil production profile compared to SWW was observed, however significant differences on the water propagation through the block was seen, Graue et al. (1997). By comparison of Figure 5 and 6 in **Paper 5**, it is evident that departing form SWW conditions reveals a water flow pattern which is quite similar to the flow without fractures. Only the open fracture had visible obstruction of the water flow.

In Graue et al. (1999) the first numerical simulations of the large block water floods were presented. As representative input data was needed, several core plugs were aged to a range of wettability conditions and shipped to a commercial laboratory for capillary pressure and relative permeability curve measurements. The relative permeability curves were measured using Penn State steady state method utilizing X-ray attenuation for saturation information. The capillary pressure measurements were performed using centrifuge.

The numerical simulator was tuned to match to the whole block experiment data using the representative relative permeability and capillary pressure input from core plug experiments performed on cores of similar wettability conditions. The next step was to use the tuned simulator input data to simulate the fractured block experiment. By varying the degree of capillary contact across the closed fractures, the difference in water transport across the closed fractures at various wettability conditions could be matched using one parameter.

Parallel to this work a new centrifuge technique was developed by Phillips Petroleum Company, Spinler et al. (1999). By utilizing high resolution Magnetic Resonance Imaging (MRI) to obtain in-situ saturation information it is possible to measure the forced and the spontaneous parts of the capillary imbibition curve at one single speed. In addition, it is possible to obtain multiple capillary pressure curves within a single core plug. This technique was applied on one of our aged core plugs and revealed non-uniform wettability conditions. The core sample was SWW in the center and MWW in the circumference. A diffusion effect during submersion in crude oil at elevated temperature was believed to cause this effect. This led to the conclusion that core plugs to be used as twin plugs to the large blocks aged at static conditions yields less water-wet wettability conditions.

By drilling samples from the large blocks and subject them to Amott wettability tests it was shown that the large blocks had an Amott index to water Iw=0.8 while the core samples used for relative permeability and capillary pressure measurements yield Iw=0.5. By changing the input data in the simulator to reflect Iw=0.8, a much better fit of the in-situ water front movement was obtained, Figure 17 in Graue et al. (1999).

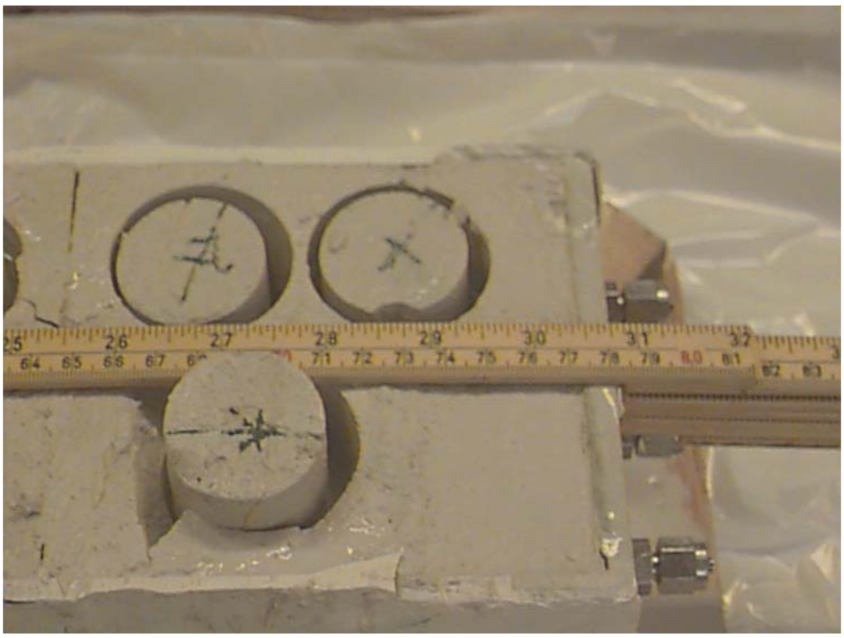


Figure 2.3: Core Plugs Drilled Out from Block to Test Wettability Homogeneity (Graue et al. 2000a).

In 2000, new fractured block water floods were presented. By adding different radioactive tracers to the connate water and the injection water, it became possible to distinguish between the two, Graue et al. (2000a). When water flooding non-fractured blocks, all connate water was produced both in the SWW and in the MWW case. However when repeating the water floods on fractured blocks, the connate water displacement revealed distinct recovery mechanisms on the SWW and the MWW blocks.

For the SWW case the connate water was displaced block by block leaving a bank of connate water at the outlet end of each block. After water break through the major flow path of the injection water was through the fracture network, hence no further movement of the connate water in the matrix blocks water was detected.

In the MWW case, the connate water displacement before water breakthrough behaved similar to the non-fractured case. The continuity between the blocks was explained by water bridges transporting both the connate water and the injected water. After water break through of the matrix blocks the injected water mainly flowed through the fracture network leaving some connate water left in the matrix blocks.

Due to non-homogeneous aging, wettability variation within a block was implemented in simulations in 2000, Graue et al. (2000b). Drilled samples from an aged block revealed a non-uniform wettability distribution along the length of the block. Corresponding input parameters in the numerical simulator were utilized in the different identified wettability zones. In addition, the capillary communication across the fractures, which is believed to follow the wettability were adjusted to reflect the respective wettability conditions. A strongly improved match in the in-situ water movement was obtained increasing our confidence in the interpretation of the recovery behavior of fractured chalk at different wettability conditions.

In 2001 a feasibility study using NTI to record “while spinning” capillary pressure centrifuge data was presented, Graue et al. (2001). The objective was to utilize radioactive tracer in the water phase and a movable gamma ray detector to provide in-situ saturation data as function of position along the core while spinning. Coarse spatial resolution and challenging detector characteristics were among the main weaknesses of the apparatus. Nevertheless the technique has good potential when it comes to reduced spinning time (one speed only) and the possibilities of reservoir temperature and pressure conditions. The method can also be expanded to measure the entire capillary pressure scanning curve, including the positive part of the imbibition curve. Improved capillary pressure curve measurements would create a better database for input to our numerical simulations.

In 2002 an aged fractured block was water flooded at several different fracture/matrix permeability ratios and both in-situ water saturation dynamics and production data was recorded, Graue and Nesse (2002). The experiments showed that the dominant oil recovery mechanism was spontaneous imbibition, however, viscous oil recovery added significantly to the total oil production when the permeability ratio between the fractured system and the matrix was less than 20. The amount of oil viscously recovered increased as the fracture permeability decreased.

2.2 Outline Description for this Thesis

This thesis is a continuation of the ongoing research program at the Reservoir Physics Group at UoB on oil recovery from fractured reservoirs. Based on the progress of the project described above, two areas of interest were chosen. Firstly, improvement of the established aging technique was needed in order to obtain more uniform wettability conditions. Secondly, detailed investigation of the water transport across fractures with emphasis on the effect of wettability conditions and fracture aperture was chosen.

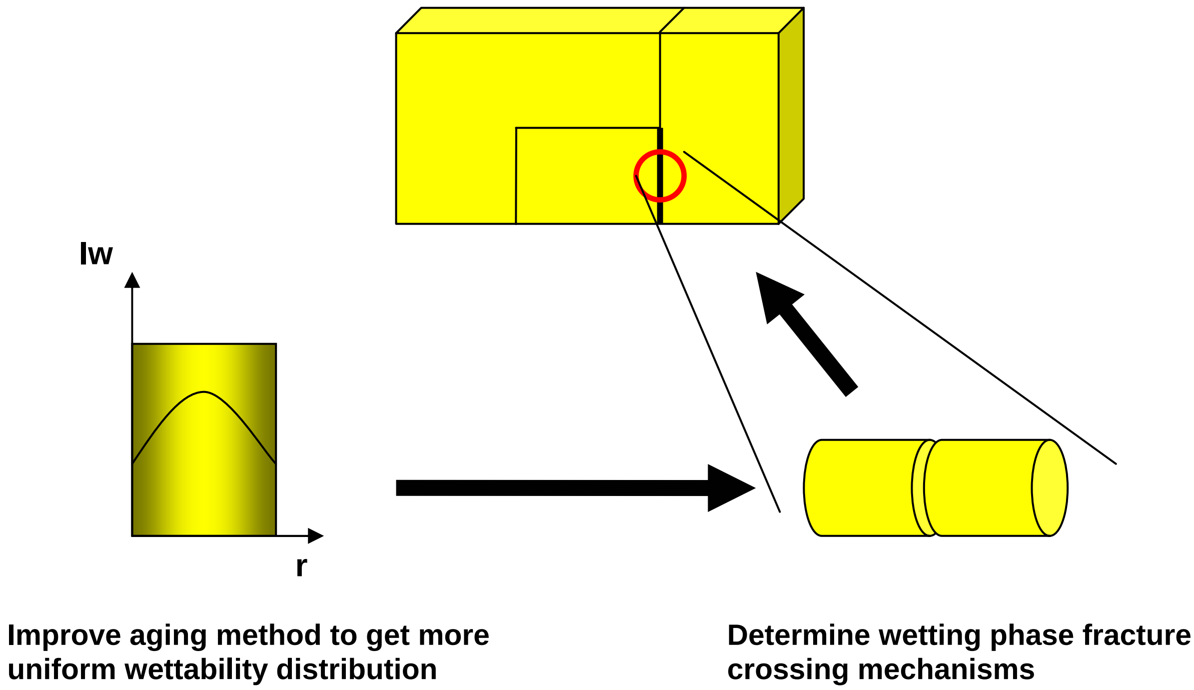


Figure 2.4: Focus areas for this thesis.

Chapter 3: Geology of Chalk Reservoirs in the North Sea Ekofisk Area

Tectonics of the earths crest resulting in tension and subsequent thinning of the crest in specific geological determined areas may result in a rift. Rifts occur today in the mid oceanic ridges, which are now interpreted as zones of sea floor spreading. Because of their lava fill and geographic location, the rift basins of mid oceanic ridges are not attractive areas for hydrocarbon exploration, Selley et al (1998). Aulacogens is where a rift has aborted and failed to open fully. One of the best known failed rifts occurs in the North Sea of Europe. When the European, Greenland and North American plates began to separate, one of the arms of the rift subsided and opened to form the Norwegian Sea.

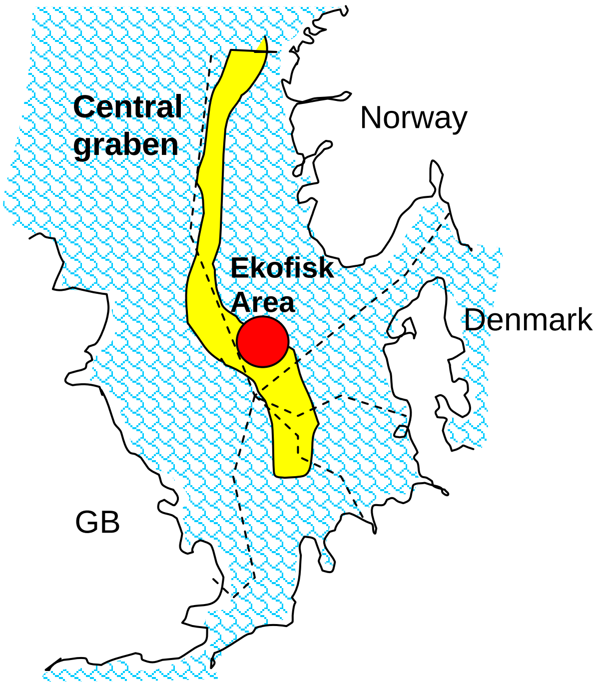


Figure 3.1: Central Graben and location of the Ekofisk Area.

Rifting began in the Permian, 250 million years ago, and continued throughout the Triassic period. Subsidence resulted in deposition of deltaic complexes and shallow marine organics growth. The chalk deposits at the sea floor mainly consist of fecal pellets from animals which fed on algae. The rate of deposition during the Cretaceous age is believed to be 1,5m/10000 years, Håkansson et al., (1974). The continuing faulting caused chalk turbidities and mélanges to shed into the graben reworking the deposits and increasing the depositional rate. This can be seen in the layering of the Ekofisk chalk with contrasts in permeability and porosity. The graben continued to be mainly in filled by marine clays. Later deformation of the sediments by salt diapirism and fault movement defined the structure of the Ekofisk field. Such salt domes are formed by buoyancy of underlying salt because the salt trapped during burying is less dense than the overlaying rock, Spencer et al. (1985).

The chalk deposits accumulating on the seafloor has an initial porosity of 70%. This rapidly compacts to 50% as the fragile chalk gets crushed during burying. Early cementation of the chalk further reduced the porosity Hardman (1982). The crushing and cementing process gives the chalk high tortuousity lowering permeability. The high depositional rate in the Ekofisk area, combined with the low permeability, resulted in trapping of sea water and increased pore pressure hence the high porosity was retented, Skotte and Fritsen (1994). The high pore pressure during deep burying is kept from escaping by shallower layers of impermeable clay. Early hydrocarbon migration caused by steep geothermal gradient in the area, resented diagenesis and further cementation of the chalk because water, which dissolves the chalk, was displaced from the pores. Early oil migration will also prevent healing fractures to seal the migration path.

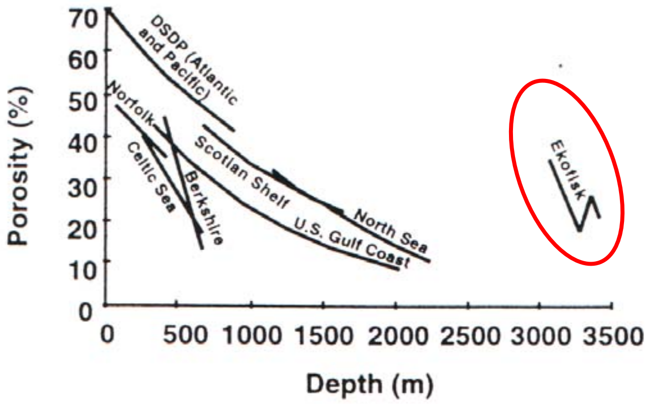


Figure 3.2: Compaction of burying sediments, (Anderson, 1995).

Fractures

Characteristics of the North Sea chalk are high porosity (30-50%) and low permeability (1-10mD), however fractures do tend to increase the reservoir permeability. Tectonic fractures in the Ekofisk field are shear or extensional fractures, formed from salt diapirism enforced by regional compressive stress causing the sedimentary layers to fold. Folding and tensioning of the brittle chalk rock material results in fracturing, Figure 3.3.

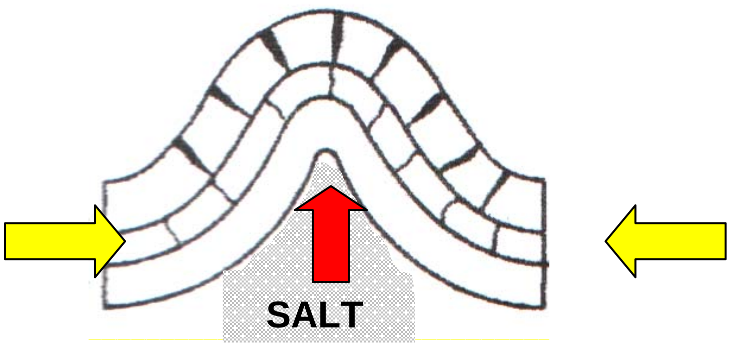


Figure 3.3: Fracturing during salt diapirism and compressive stress

Parameters like lithology, fracture type, fracture pattern, mineralization, dip, fracture length, spacing, strike and permeability of natural fractures can be investigated on samples from core drilling. Using core samples for discovering fractures is difficult because first and foremost core samples represent a small fraction of the total reservoir volume. The test samples may also no longer be in the same state or have the same properties as in the undisturbed reservoir. Fractures are hard to detect from bore hole logging and cannot be detected from seismic.

Fracture aperture and frequency may be dependant on location in a reservoir. Factors like depth and distance from faults/domes are important. Fracture frequency in the Ekofisk field is approximately one fracture every foot, and one fracture may extend for tens of meters.

Chapter 4: Wettability in Core Analysis

4.1 Introduction to Wetting Theory

The accumulation of oil in a reservoir represents a process of partial displacement of reservoir brine with the crude oil. During this process, oil approaches the mineral surfaces, but remains separated from them by very thin (typically less than 50nm thick) water films. Hirasaki (1990a, 1990b and 1991) has argued that wetting in these oil-brine-mineral systems will be determined by the thickness of this water film, which in turn is determined by the balance of forces which act with the film. These forces give rise to the excess pressure, the disjoining pressure, which acts to resist further thinning of the film. The film will drain (become thinner) until its disjoining pressure is equal to the applied capillary pressure. Hirasaki (1990a and 1990b).

Surface force measurements across thin liquid films have been conducted with many different systems. The force-distance profiles are typically described in terms of three components: electrostatic interactions, van der Waals dispersion forces and structural or solvent forces, Israelachviliv (1991). If the electrostatic interaction is *repulsive*, it may be sufficiently strong to overcome the van der Waals attraction, thereby stabilizing a relatively thick film. This is expected to produce water wet conditions, Melrose (1982), Buckley et al. (1989) and Hirasaki (1990b). If the electrostatic force is *attractive*, or if it is not sufficient *repulsive*, the water film will continue to decrease in thickness until further thinning is limited by short range, *repulsive* forces. At this lower film thickness (mono layer), the surface will not be water-wet.

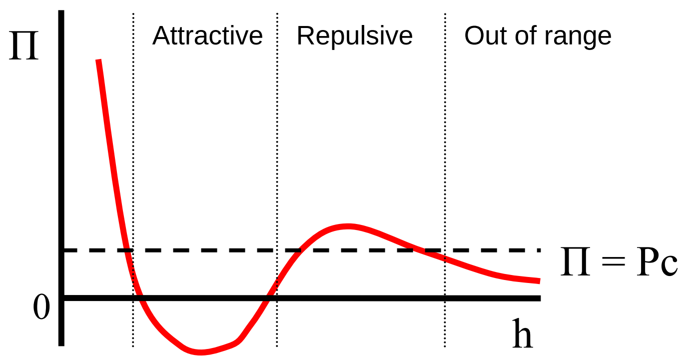


Figure 4.1: Disjoining pressure (Π) as function of water film thickness (h).

The conditions for equilibrium of a system with two interfaces are described by the Young-Laplace equation:

$$P_c = p^{\alpha} - p^{\gamma} = \prod + 2H^{\alpha\gamma}\sigma^{\alpha\gamma} \tag{4.1}$$

where H=mean curvature, $\sigma^{\alpha\gamma}$=interfacial tension, p^{α}-p^{γ}= capillary pressure and Π is the disjoining pressure. The temperature and chemical potential are assumed constant. Where the separation of the interfaces is large, Π=0 and Equation 4.1 reduces to the capillary pressure. If one of the bulk phases is a flat solid, the mean curvature of the fluid/fluid interface is zero where the interfaces are parallel. Here P_c=Π. $H^{\alpha\gamma}$ is positive on concave surfaces and negative on convex surfaces. Thus, instability of a film on a rough surface will first occur at points of protrusion. This might be the situation of fractional wettability.

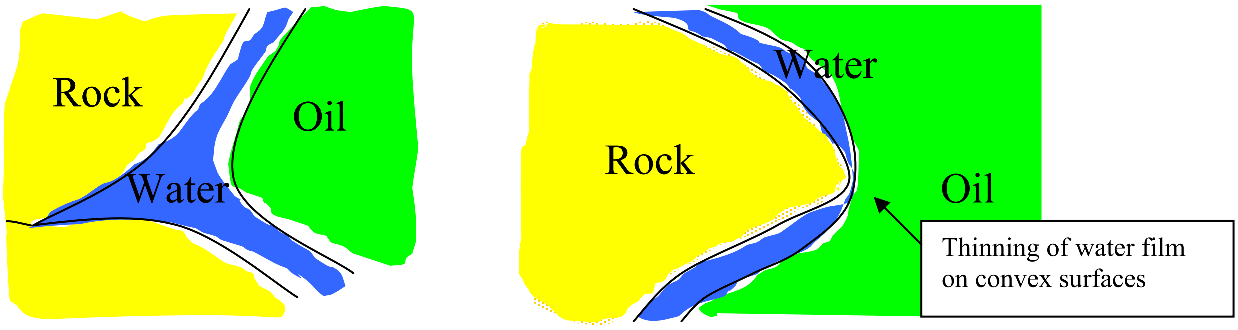


Figure 4.2: Left; concave rock surface and Right; convex rock surface.

Fractional Wettability

Fractional wettability introduced by Brown and Fatt (1956) is also called heterogeneous, spotted or Dalamation wettability. It occurs when only certain areas of the grain surface are altered while the rest remains water wet. These areas of altered surface wettability can be divided into two main sections determined from Equation 4.1. First the convex surface areas are subjected to water film disruption at a lower capillary pressure than the concave areas, Figure 4.2. Secondly, different mineral surfaces may have different electrostatic properties leading to variations in the disjoining pressure and hence variation in water film thickness. The Cryo technique provides excellent information by visualizing the wetting properties on pore scale. Fassi-Fihri (1991) shows images of oil wetting sites on convex surface areas and on certain minerals on core plugs aged by crude oil.

Mixed Wettability

The theory of mixed wettability was brought up by Salathiel (1973). When oil enters a preferentially water wet rock, the large pores are drained by crude oil whereas pores smaller than the corresponding applied capillary pressure remains water filled. Only the large pores will be exposed to the active aging components in the oil and hence be subjected to wettability alteration. This specific phenomenon is called mixed wettability or mixed wet large (MWL) because only the wettability of the large pores is altered. Hamon presented in 2000 an extensive study including a large number of core samples taken from one single reservoir. The results were categorized with respect to absolute permeability. Using centrifuge, core samples from within the same height in the reservoir clearly show that at maximum capillary drainage pressure, the water saturation varied from 30% in 1mD cores to 10% in 1000mD cores. Also the wettability measurements on these core samples revealed decrease in wettability from 0.25 to near 0 when going from samples with 1mD absolute permeability to 1000mD which reflects that more of the pores are invaded by oil in the high permeability case.

The results from these experiments are consistent with several publications where high spatial resolution Cryo-ESEM technique are utilized to investigate mixed wettability conditions on pore scale (0.1μm), Fassi-Fihri (1991), Robin et al. (1999) and Kowalewski (2003).

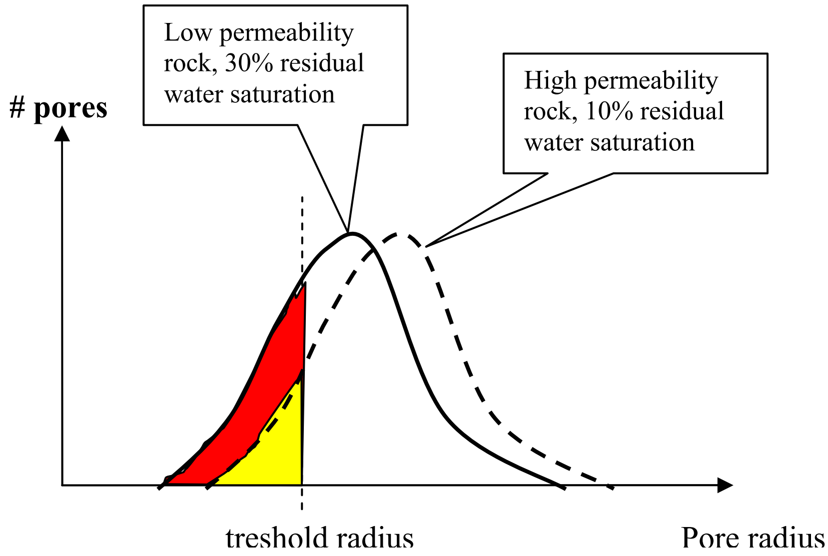


Figure 4.3: Schematic of pore size distribution vs. max capillary drainage.

The outcrop rock used in our study is subjected to drying, water saturating and drainage by crude oil followed by an aging period. The wettability conditions are then most likely to a mix of both fractional wettability and mixed wet large wettability.

4.2 Wettability in Core Analysis

In the reservoir development stage, data from core plugs retrieved from exploration wells is evaluated. Since the wettability has a profound effect on the flow functions it to large extent controls the expected reservoir response to different recovery methods and most importantly the estimation of the recoverable reserves. It will also be helpful when decisions on oil recovery strategy contemplated. In a fractured reservoir relying on recovery by water imbibition into matrix blocks, wettability in some cases are the single most important reservoir parameter.

When collecting core samples from a well bore, the core and its natural environment is altered in several ways. This can be:

- Intrusion of drilling mud may alter the pH
- Temperature and pressure changes may cause light ends to evaporate
- Temperature and pressure changes might be responsible for heavy component precipitation
- If the core is allowed to dry out, residue of crude oil will deposit on the rock surface
- The mechanics of drilling, drilling fluid pressure, core handling and transport may cause mechanical destruction like fractures

Hamon (2004) recently reviewed 250 wettability tests performed at the Ekofisk Field in the North Sea. The motivation was the scatter in the test data and the discrepancy between laboratory data and the field water injection results. The data was sorted with respect to test parameters like type of drilling mud, test conditions, sample porosity, sample permeability, estimated initial water saturation, imbibition test oil type, core cleaning, formation, depth and elevation above free water level (FWL). The result showed that elevation above FWL was the single most important parameter. A clear tendency of increasing water-wet characteristics with depth was also detected.

Chapter 5: Wettability Effects on Water Flood Performance in Fractured Chalk Reservoirs

Being the parameter controlling fluid distribution on the pore level, it becomes clear that wettability does have a profound effect on fluid flow properties controlled through the local capillary pressure and relative permeability curves. In low permeable fractured chalk reservoirs where oil recovery by water flooding to a major extent is controlled by the spontaneous imbibition, the wettability conditions in some cases are the single most important factor.

In a case study on new development projects by Bouchard and Fox (1999), effect of core analysis data from fractured reservoir in the exploration stage were investigated. Figure 5.1a below is a simplified Net Present Value (NPV) influence diagram for an oil reservoir development with the core analysis input in the top of the figure and the economical influence in the bottom of the diagram. The uncertainties on core analysis parameters can be derived from available core data or in early stages from analogues, exploration-well logs or testing. Thereby the probability distribution of each parameter is calculated. Comparing NPV from models with a range of different realizations (Monte Carlo simulation) will provide distribution of NPV. This technique includes interdependencies of the different parameters and as a result is capable of defining the most influential uncertainties.

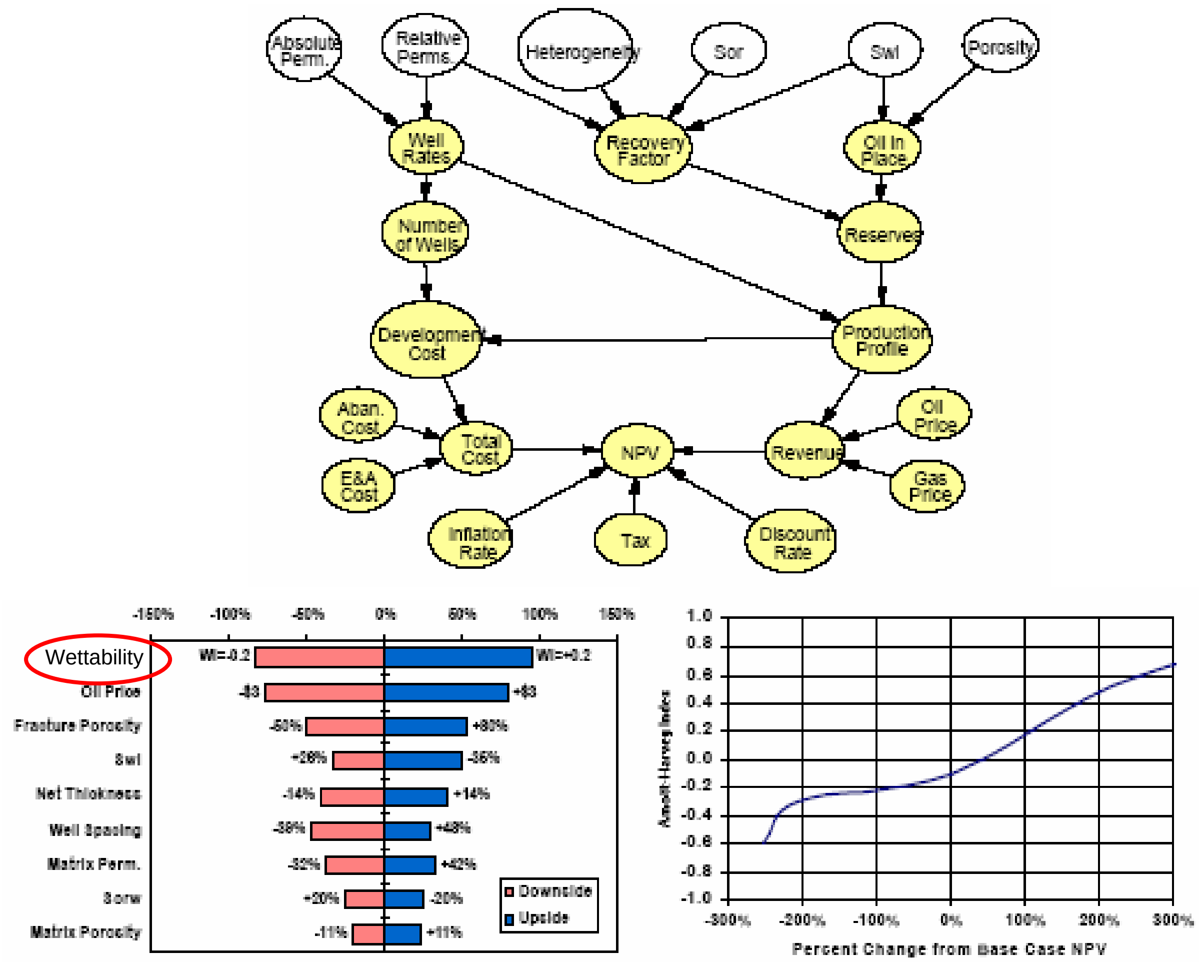


Figure 5.1: a) NPV influence diagram, b) Tornado chart of main uncertainties (value in percent change from base case NPV) and c) Impact of wettability on NPV, Bouchard and fox (1999).

In the reservoir case under study, three exploration wells are drilled and logs have been run in each well. From the well logs good porosity and lithographic data were provided, however the measurements on water saturation were poor. Well tests performed suggested heavily fracturing and decision on water injection was made. Due to the faulting and local fracturing, the number of wells and well spacing turned out to be important. Based on the collected data, a reservoir model was made and numerical reservoir simulations were performed. Results from their simulations showed that the transfer function, which depends on wettability, was the key uncertainty. Figure 5.1b show the most important parameters on the uncertainty in the NPV of this reservoir. It shows that wettability has the most significant influence followed by the oil price and can alone cause the NPV to vary close to ±100%. In Figure 5.1c the NPV is plotted against the Amott index. The non-linearity is caused by the contribution from gravity assisted recovery. Decisions were made on performing coring from the formation in order to provide core material for wettability testing.

As mentioned earlier, the matrix permeability of the Ekofisk chalk field is 1-10mD. Only a few oilfields, for example the Dan Field in Danish sector, of such low matrix permeability can produce at commercial rates, Damgaard and Weaver (1993). However, fracturing due to folding and compressional stress of the reservoir rock may increase the field permeability 10-100 times. Consequently the permeability of fractured reservoirs is subdivided into three constituents: matrix-, fracture- and system-permeability. Well tests indicate system permeability of up to 150mD in the Ekofisk field, Dangerfield et al. (1987). The high system permeability causes a high production rate during pressure depletion. However the reservoir depletion led to reservoir compaction and reduction of system permeability. This was one of the reasons why a water injection pilot was initiated in the Ekofisk field in 1986. Another reason was that water injection would act as a secondary recovery method. In strongly water wet reservoirs like the Tor formation, the water injected into the fractures spontaneously imbibes into the matrix blocks repulsing the oil into the fracture network, illustrated as point 1 in Figure 5.2 below. The oil will follow the fracture network to the producers.

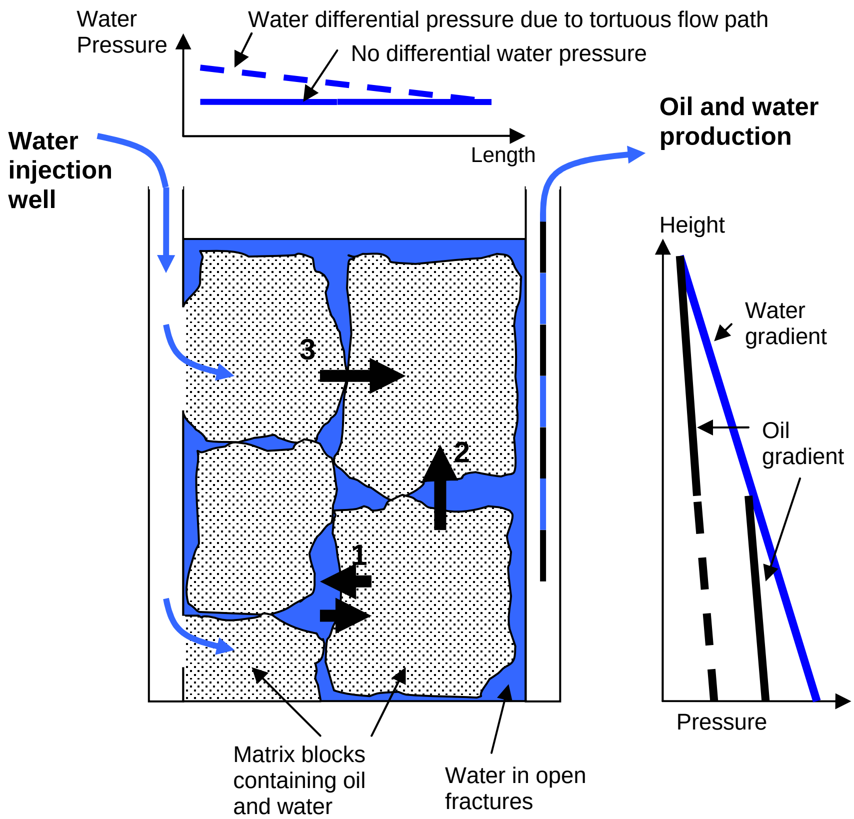


Figure 5.2: Schematic of recovery mechanisms in moderately water-wet low permeable fractured rock.

However at less water-wet conditions the recovery mechanisms change. The spontaneous imbibition of the injected water in the fracture network into the matrix blocks is reduced and the residual oil saturation of each matrix block is higher. As illustrated in Figure 5.3 below, the capillary pressure becomes zero and hence spontaneous imbibition halts at higher residual oil saturation. In addition some of the oil expelled from matrix blocks located deeper in the reservoir will re-infiltrate the shallower blocks, point 2 in Figure 5.2 above. This tends to slow down the recovery process and reduce the ultimate recovery Van Golf-Racht (1982) and Uleberg (2005).

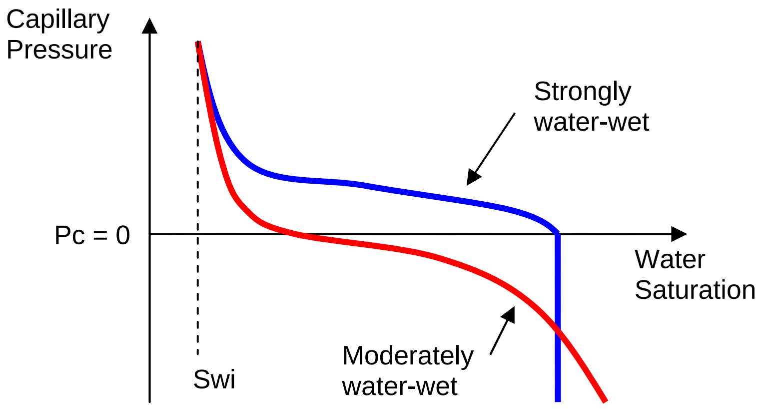


Figure 5.3: Illustration of capillary pressure in strongly and in moderately water-wet rocks.

As can be seen in the illustration of the capillary imbibition curves in Figure 5.3 above it is possible to reduce the residual oil saturation significantly by only a slight negative capillary pressure. Negative capillary pressure occurs when the wetting phase, in this case the water exhibits higher pressure than the non-wetting phase. The classical example of this situation is illustrated in Figure 5.2, where water has been injected into the reservoir and the fracture network filled with water surrounds the matrix blocks. Access to water will initiate a spontaneous imbibition process only limited by the end point residual oil saturation at zero capillary pressure. Now, the density difference between the oil and the water will cause a negative capillary pressure resulting in further reduction of the residual oil saturation. The recovery now strongly depends on the effective height of the matrix blocks. The effective height of the stack of matrix blocks is the height of which oil is in hydraulic continuity. Uleberg (2005) has done detailed work on numerical simulations of forced imbibition by gravity of fractured low permeability reservoirs. He concluded that residual oil saturation was reduced significantly when increasing the stack height.

In the research program of the Reservoir Physics group at UoB emphasis is on the possibility of a horizontal pressure gradient. In the Ekofisk field the stack height is low due to interlayers of impermeable shales reducing the vertical communication. The water flow will tend to follow the path of least resistance and the tortuous path of the fracture network reduces the fracture/matrix permeability ratio and thereby the system permeability. This will increase the water gradient between the injection well and the producer. If there is sufficient horizontal capillary continuity between the adjacent blocks, flow through the matrix blocks might be an additional flow path for the water phase. The capillary contact may consist of physical contact point of the matrix blocks or being hydraulic continuity across open fractures through water bridges. The water pressure gradient across the blocks will result in a viscous displacement as an additional recovery mechanism (Hamon, 2004). Unpublished results show that the differential pressure in certain parts of the Ekofisk field is approximately 1psi/ft.

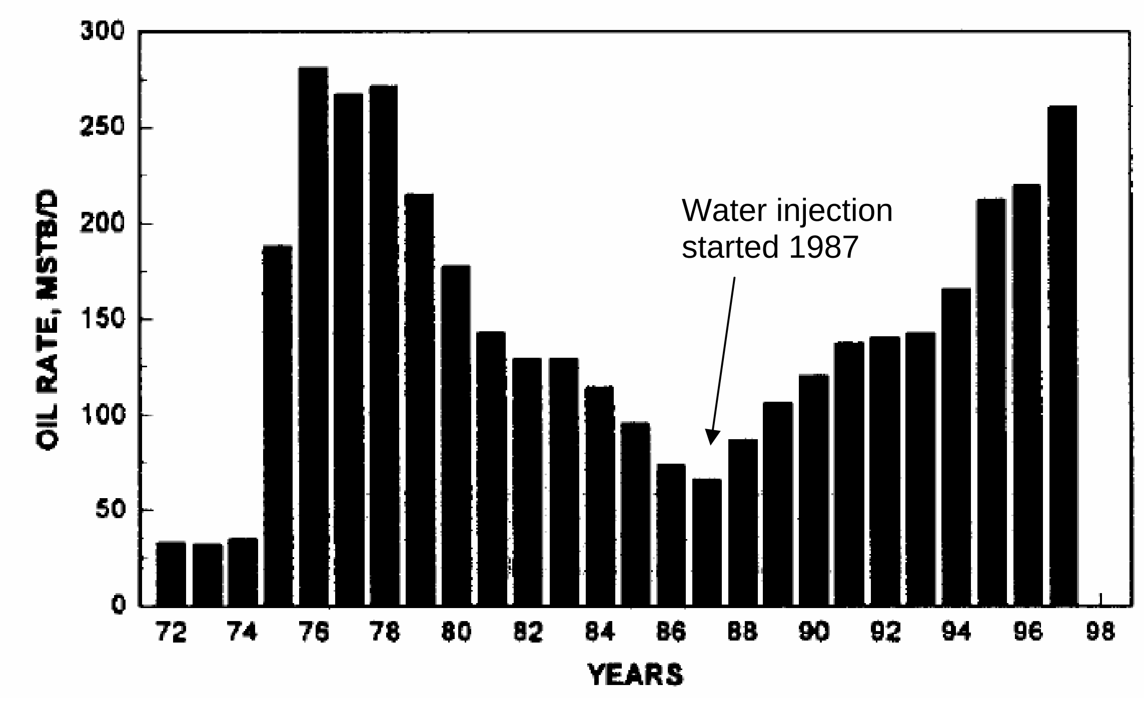


Figure 5.4: The effect of water injection on the Ekofisk oil production profile (Hermansen et al. 1996).

Part 2

Work & Discussion

Chapter 6: Experimental Methods and Apparatus

6.1 Core preparation

An outcrop evaluation study performed by Lie (1995) showed that the Portland quarry near Ålborg in Denmark contains fractured chalk comparable with the one found in Ekofisk field in the North Sea with respect to porosity, permeability, imbibition characteristics and mineralogy. Quarried pieces of chalk were transported to the University of Bergen and dried slowly at room temperature.

Details on core preparations can be found in Paper 1 and 2. In short the core preparations can be listed as follows:

- The cores were stored at 60°C for minimum 3 days to reduce humidity.
- During vacuuming to 10 mBar an in-line ice trap helped removing remaining humidity
- Allowing degassed brine (5wt% NaCl + 3.8wt% $CaCl_2$) into the cores. $CaCl_2$ was added to the brine to minimize dissolution of the chalk. Sodium azide, 0.01 wt.%, was added to the distilled water to prevent bacterial growth.
- The cores were stored in brine for 5-10 days to reach ionic equilibrium with the rock constituents.
- Porosity was assumed to be homogenous throughout the core plug and hence determined from bulk measurements and the difference in weight before and after vacuum saturation. Absolute permeability was calculated using Darcys law. Due to the fragile nature of the chalk material, net confining pressure was less than 10 bar (147 psi) to keep the cores in the elastic compression region.

Figure 6.1: The author climbing the chalk quarry in Ålborg, Denmark

6.2 Aging

In order for the outcrop core plugs to represent different wettability conditions, the chemical properties of the rock material surface were altered by exposure to crude oil at elevated temperature. A simple analysis of the crude oil used in these experiments is shown in Figure 6.2. The acid number was measured at 0.094 and the base number at 1.79.

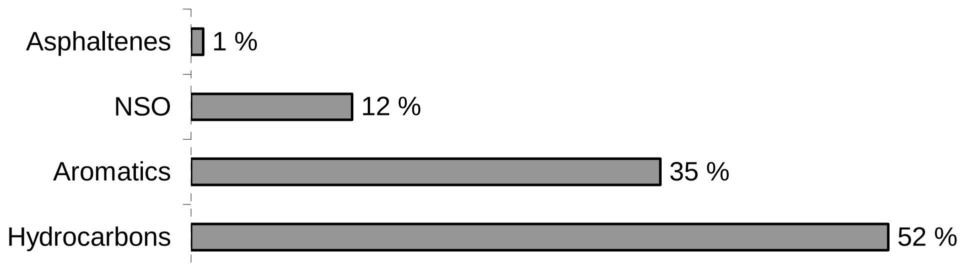


Figure 6.2: Composition of the Crude oil used.

The aging procedure is as follows:

- Heat up oil and core holder system.
- Drainage to Swi by filtered crude oil.
- Flooded in opposite direction for water saturation redistribution.
- Aging by continuous flow of crude oil in alternating directions.
- Displace crude oil by buffer fluid (Decaline).
- Displace buffer fluid by n-decane.
- Cool to room temperature.

To avoid wax precipitation the temperature was maintained at 90° C as long as crude oil was present in the rock sample and decaline was used as buffer between the crude oil and the mineral oil. A back pressure of 4bars was used to prevent gas evaporation from the heated oil. Initial water saturation of 25% was chosen as a baseline for our water flooding experiments, based on pressure limitations of Swi during oil floods in the large blocks. The core plugs were oil flooded to initial water saturation using crude oil filtered in-line through a piece of oil flooded and aged core plug to avoid plugging the porous media. The produced fluid was analyzed to detect any water production or evaporation during the flooding.

6.3 Nuclear Tracer Imaging

Nuclear Tracer Imaging (NTI) is used for in-situ fluid saturation monitoring. This technique was developed by Bailey et al. It operates by detecting gamma emission from liquid phases labelled with a nuclear tracer. Using a collimator it is possible to measure the fluid saturation in a selected section of the porous media. By moving the collimated detector along one or two axis, one or two dimensional saturation images can be generated. A detailed description of the NTI apparatus can be found Lien et al. (1988).

6.4 Basics of Nuclear Magnetic Resonance

Nuclear Magnetic Resonance (NMR) is mainly used in diagnostic medicine. Bloch and Purcell got the Nobel price in 1952 for being the first making this method work. The technique measures the amount of hydrogen present by detecting the energy released during relaxation after the spin of single protons have been aligned with an applied magnetic field. Magnetic Resonance Imaging (MRI) denotes the application of NMR to produce images.

The applied magnetic field causes the spin of the protons to process with a frequency dependant on the applied field (B_0) and the gyro magnetic ratio (γ) of the nucleus. The frequency is called the Lamor frequency and is given by:

$$f_L = \frac{B_0}{\gamma} \tag{6.1}$$

The B_0-field is created by the permanent magnet of the NMR apparatus, while the γ is dependant on the fluid in the core sample.

By applying a Radio Frequency (RF) pulse, at the Lamor frequency, it is possible to excite the aligned spin of the protons from their relaxed orientation. When releasing the RF pulse, the spin of the protons will again release electro magnetic energy through relaxation back to the orientation of the magnetic field. This is called inversion recovery.

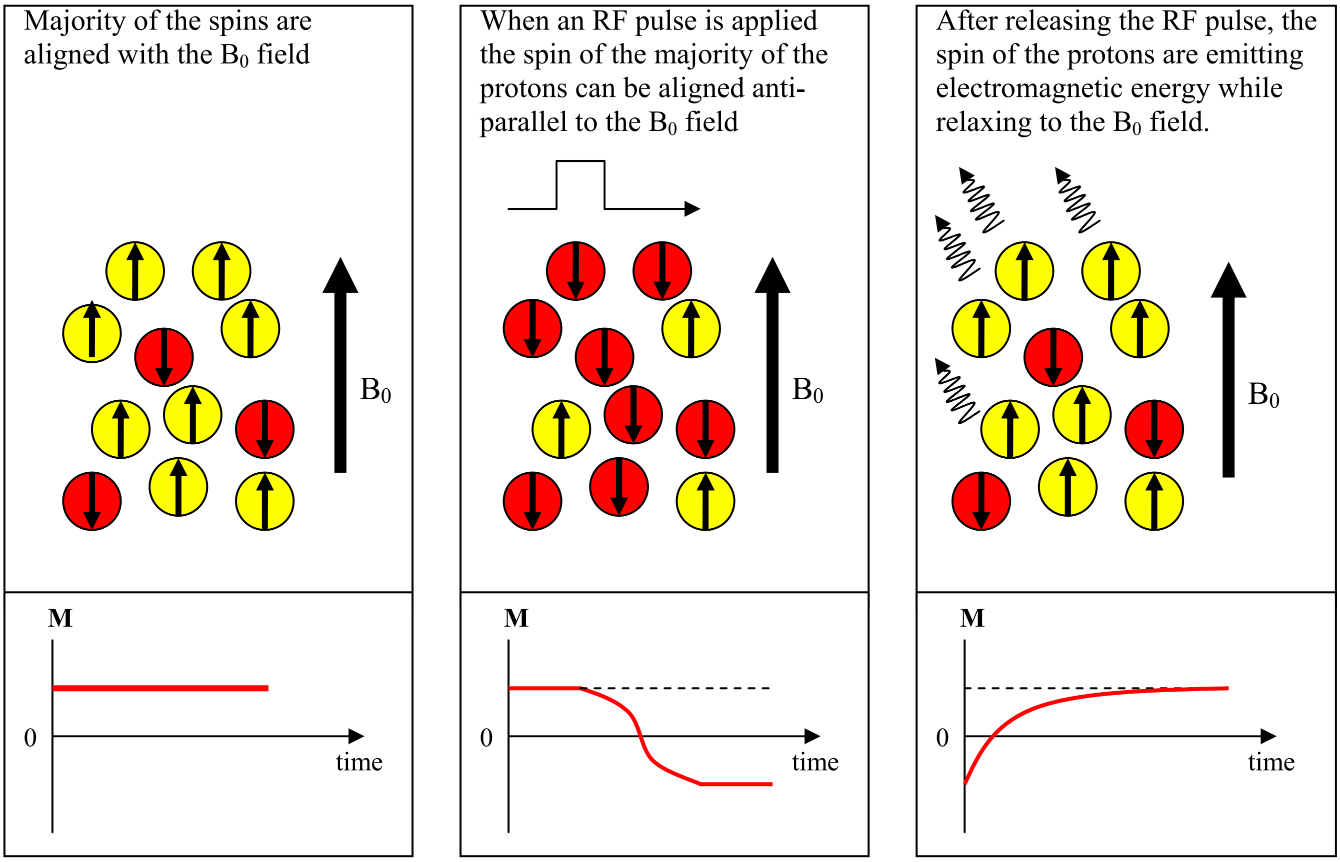


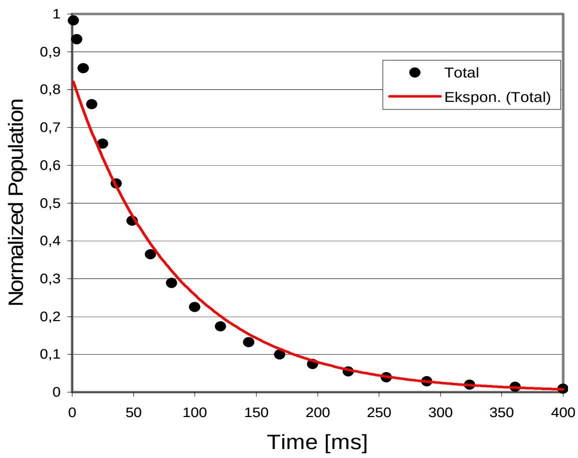
Figure 6.3: Schematic of the relaxation process of NMR.

The inversion recovery method does not distinguish between the signals from the hydrogen in the water and the hydrogen in the oil. Therefore the water phase used in our experiments is exchanged with heavy water (deuterium). The nucleus in the deuterium has zero nuclear spin and thus does not respond to the RF signals used.

In the experiments where we needed to know the saturation of both the water and the oil phase, the NMR spectroscopy was utilized. The spectroscopy uses another pulse sequence called Carr-Purcell-Meiboom-Gill (CPMG). As the protons are allowed to relax the coherence in the Larmor precision tends to fade due to local microscopic magnetic inhomogeneities of the rock surface. The wetting fluid close to the rock surface looses its total coherence faster than the non-wetting fluid isolated in the center of the pores; hence it is possible to distinguish between the two phases by the shape of the exponential decay curve. If the curve is fitted to more than one exponential, the saturation of each phase can be obtained from the population coefficient for the corresponding exponent at t=0, Equation 6.2 and Figure 6.4.

$$Signal = \sum_{1}^{N} C_i \cdot e^{-\frac{t}{T2_i}} \tag{6.2}$$

where C_i is the population coefficient of phase i, t is the time and $T2_i$ is the time exponentials to fit.



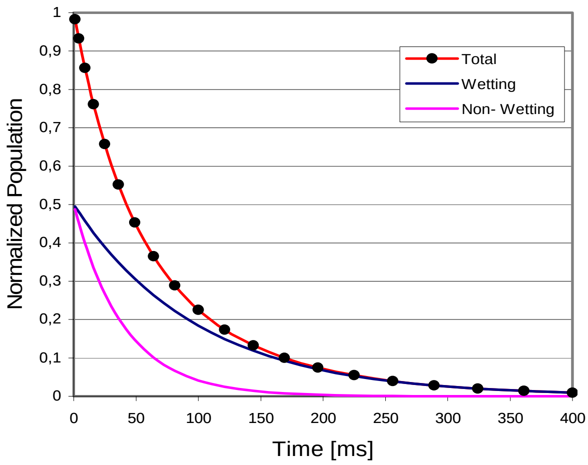


Figure 6.4: Left: Best single exponent fit to the decay curve. Right: Equation 6.2 solved for two selected exponentials. Saturation of each phase can be read directly form the normalized population axis.

6.5 Applications of NMR Spectroscopy

The low field NMR spectrometer used in our experiment has the capability of performing whole core T_2 measurements. This is used to find the residue of regular brine in the core samples subjected to miscible displacement between the regular brine and the non imagable heavy water at S_{or}. Equation 6.2 is fitted to the decay curve using 100 selected exponentials by minimizing an object function by varying the population coefficients. The T_2 measurement provides information on the efficiency of the miscible displacement as well as any changes in the oil saturation, see Figure 6.5. Because the water and oil have different densities and hydrogen indexes, these have to be normalized for.

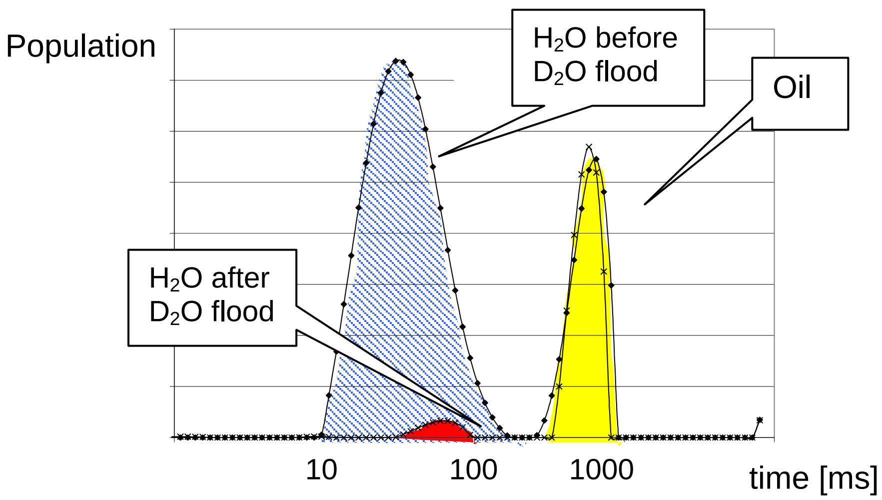


Figure 6.5: NMR spectroscopy of core CPA-6.2 before and after D2O flood at Sor.

6.6 Fracture crossing experiments

During the fracture crossing experiments, dynamic fluid saturation distribution for both the fracture and matrix blocks were monitored utilizing the MRI. Using deuterium as the brine only the oil phase (decane) was monitored. The MRI intensity is not perfect linear within the entire saturation range in the Rørdal chalk used in this thesis, however there is a good linear correspondence between saturation and MRI intensity in the saturation range between S_{wi} and S_{or}.

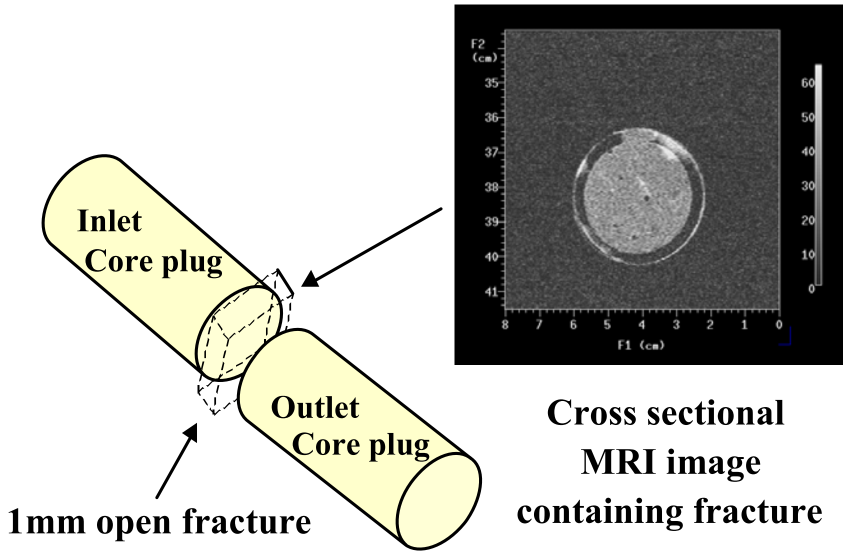


Figure 6.6: Schematic of open fracture imaging.

Figure 6.6 illustrates an MRI image of the oil in the open vertical fracture between two core samples during a fracture crossing experiment. In the experiments reported in Paper 3, two 6cm long core plugs 3.8cm diameter were stacked, however in the experiments reported in Paper 4, one 6cm long core plug were cut into two 3cm pieces to ensure equal wettability conditions at both sides of the fracture.

As listed in table 5.1 water floods reported in Paper 3 were performed at each of the three selected wettabilities 1.0, 0.7 and 0.5 Amott Harwey Index to water, Iw. The injection rate was chosen to be 0.4ml/h for comparison with the large block experiments conducted by the Reservoir Physics Group at the University of Bergen.

In Paper 4 the selected wettability conditions were Iw= 1.0, 0.6 and 0.3. In addition, the impact of different fracture aperture (1.0mm, 2.3mm and 3.5mm) and flow rates (0.4ml and 2.0ml/h) were investigated.

	Core Wettability, Iw	**Fracture Aperture**	**Water Injection Rate**
	(Amott Index to water)	[mm]	[ml/h]
Paper 3			
Experiment 1	1.0	1	0.4
Experiment 2	0.7	1	0.4
Experiment 3	0.5	1	0.4
Experiment 4	0.5	2	0.4
Paper 4			
Experiment 1	1.0	1	2.0
Experiment 2	0.6	2	0.4
Experiment 3	0.6	3	0.4
Experiment 4	0.6	3	2.0
Experiment 5	0.3	2	0.4
Experiment 6	0.3	3	0.4
Experiment 7	0.3	3	2.0

Table 6.1: Overview of water floods performed.

6.7 Large Block Experiments

The benefit of utilizing large blocks is the inclusion of all the acting forces: capillary, viscous and gravity, within a single sample. In addition the end effects will be less significant than in the small core samples, the larger volume and rectangular shape makes it easier to describe in a numerical simulator and there is opportunity to implement a more advanced fracture network combining both open and closed fractures. 2-dimensional NTI was utilized to monitor the saturation dynamics while water flooding.

The large chalk blocks were first water flooded as a whole block (oil flooded to S_{wi}) and then the water flood is repeated, this time the block is fractured. This procedure made it possible to isolate the effects from the fractures. The fractures were cut with a band saw and reassembled to produce "closed" and open fractures. The "closed" fractures were assembled with the matrix in contact and a small axial force applied during the assembly to provide matrix-to-matrix contact points. The open fracture was held at 2mm, with a Teflon® spacer. The fracture network shown in Figure 6.7a contains embedded fractures only, while interconnected fractures in Figure 6.7b assured hydraulic continuity from the inlet to the outlet.

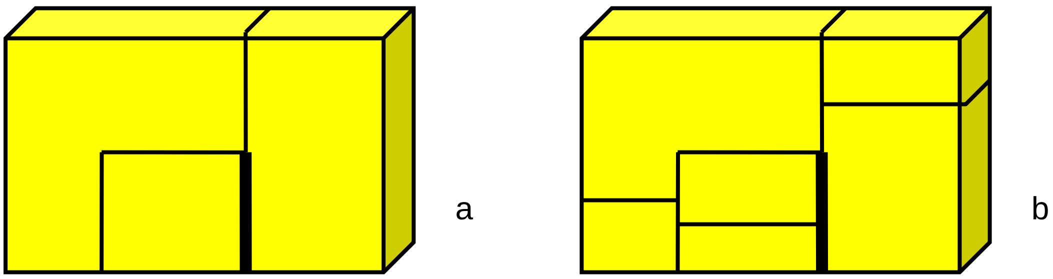


Figure 6.7: Schematics of large block fracture representation. (Left) Embedded fracture network, (right) interconnected fracture network with an isolated block.

Chapter 7: Results and Discussion on Wettability Alteration Experiments

7.1 Aging Parameters

At the University of Bergen aging of chalk is performed by exposure to crude oil. Aging parameters like water saturation, aging time, aging temperature and oil composition influence the aging and was investigated in Paper 1.

The lower the water saturation, the thinner the water films will be, and the interaction between the oil and rock surface becomes more significant. Figure 14 in Paper 1 reveals a significantly higher aging effect on the core plugs containing approximately 20% water saturation than those containing 25%. Similar results are reported by Jadhunandan and Morrow 1991, Dubey and Waxman 1991 and Zhou et al 2000. Jia et al 1991 reported that no aging effect was observed above 35% water saturation.

The time period of mineral surface exposure to the oil has an effect on aging. Figure 1 in Paper 1 shows that the effect of aging systematically increases with increased time of the exposure to crude oil. Graue et al (1998), Jadhunandan and Morrow and Jia all present similar time dependency.

Graue et al. (1994) performed aging experiments on low permeable chalk showing that oil containing asphaltenes used at elevated temperature yielded aging effect whereas if only one of these two parameters were present, no aging was observed.

The solubility of asphaltene in crude oil changes significantly with temperature. This might be one of the reasons why higher temperatures yield more efficient aging. In fact, Jia presented results of a large number of core plugs aged in two different crude oils at different temperatures. They observed that a threshold temperature below which no aging effect occurred and this temperature were different for the two oils. Above this threshold temperature the effect of aging increased with temperature.

7.2 Aging Procedure

While a majority of the presented literature on core plug aging reports the use of submersion in crude oil at elevated temperature, we have found reason to question the procedure when applied on low permeable chalk. In 1999 Spinler in collaboration with the Reservoir Physics Group at the University of Bergen found that low permeable chalk (1-10mD) aged by submersion in crude oil, yielded a non-uniform radial wettability distribution. It seemed like the low permeability rock allowed circulation of oil, driven by diffusion, between the rock and the surrounding oil in the outer part of the core only. This led to exposure of more aging components oil to the outer radial part of the core sample leaving the center of the core plugs strongly water-wet.

These results were combined with work presented by Jia, where the aging effect was shown to increase by increased amount of pore volumes of crude oil flown through during aging (1-40PV). It is believed that the aging components in the crude oil are adsorbed on the mineral surface until equilibrium is established between the oil and the surface, and no further aging will take place. Flushing of crude oil while aging at elevated temperature will prevent the radial effect and enhance the effect of the aging process by continuously adding active aging components, Paper 1 and 2.

It turned out that when applying the flushing method on core samples using one single direction of flow throughout the entire aging time period, the wettability was significantly altered at the inlet of the plug while the outlet remained water-wet. Long core plugs where subjected to flow of crude oil alternate from both ends during aging. In-situ water saturation information provided by NTI during whole core Amott tests showed that more uniform wettability distribution was obtained, especially if the ends are cut off.

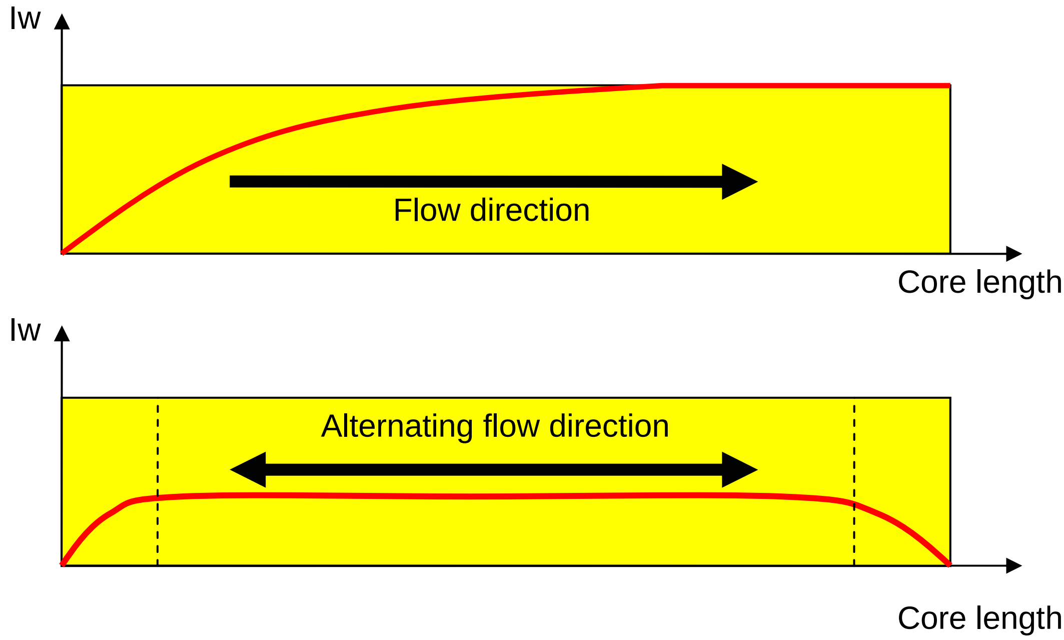


Figure 7.1: Unidirectional flow during aging (top), multidirectional flow during aging (bottom).

The ultimate goal of the development of this improved aging procedure was to develop a method which effectively and reproducibly alters the wettability condition uniformly throughout the entire core sample. In order to test this, two-dimensional saturation images were provided by MRI for each step of the Amott test, (i.e. S_{wi}, $S_{w.imb}$ and S_{wf}) performed on core 6cm long plugs aged by multi-directional oil flow. Hence, detailed two-dimensional maps of the wettability distribution could be obtained. Figure 10 in Paper 2 shows two-dimensional plots of the wettability distribution in a core plug aged to a wettability condition reflecting an Amott water index Iw=0.2. The wettability index is in the range of 0.1-0.3 in the major parts of the core plug. The radial effect is eliminated, and there is only a trace of the end effect.

7.3 Conclusions on Wettability Alteration

It has been shown in the literature that low permeability rock subjected to wettability alteration by submersion in crude oil at elevated temperature may produce non-uniform wettability conditions within a sample. Therefore it was decided to develop an improved aging technique. The advantage with this new aging method is that a uniform wettability distribution is obtained by replacing stagnant aging by continuously flushing with crude oil.

- The adsorption of active aging components while flooding with crude oil during aging is found to be decreasing with increasing distance from the inlet face of the core. This can be compensated for by multidirectional aging.
- The active aging components are capable of altering the surface of the rock at high efficiency when the filtration velocity is around 0.5cm/h. If filtration velocity is increased significantly above this level the wettability alteration will be less effective. With no flow during aging in a core holder very little aging was observed.
- By using constant flow of crude oil during aging, the rock surface is getting exposed to a higher number of active aging components than what will be the case by diffusion in a closed container. Therefore this new aging method is more effective.

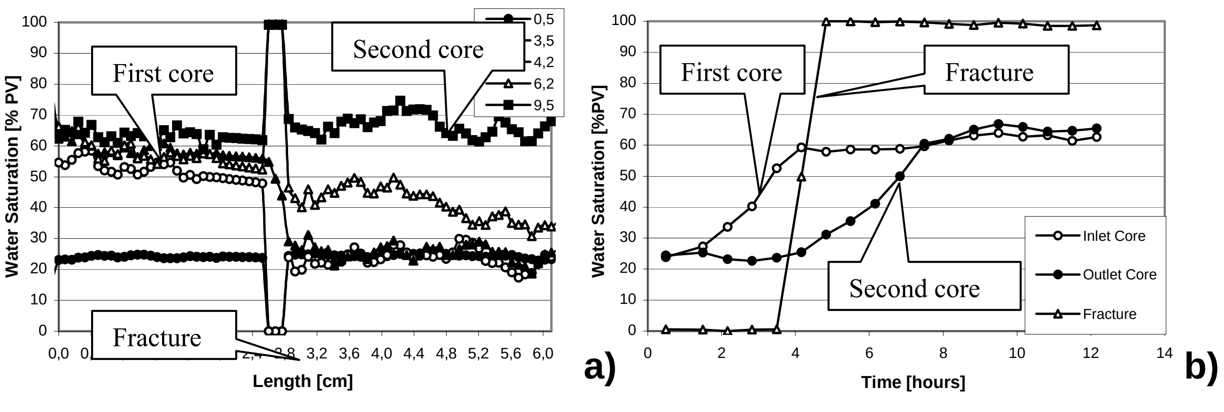
- In-situ wettability distribution has been measured and matches the data from the standard Amott test. This has been used to optimize the aging technique to be able to selectively produce core samples of desired wettability and with homogeneous wettability conditions in all three dimensions.

Chapter 8: Results and Discussion on Fracture Crossing Experiments

A number of laboratory experiments investigating communication across open fractures have been reported, however most of them have emphasis on gravity drainage. As described in the literature survey, common findings from the early experiments are poor capillary continuity between stacked core plugs unless some sort of porous medium, sand grains, paper sheet or glass bed is present in the fracture. At strongly water wet conditions the low contact angle will not allow for formation of liquid bridges. One of the few publications investigating this phenomenon is presented by Stones et al. (1992). They hypothesized that liquid bridges were the only explanation for the high oil recovery and production rate from their horizontal stack of core plugs. The core plugs were stacked on top of each other with the end faces in direct contact. Due to minor irregularities on the core end surfaces the spacing between the core plugs were estimated to be less than 2mm everywhere, and in direct contact in at least one area. The way they managed to increase their production was by introducing surfactants in order to lower the interfacial tension and hence the water/surface contact angle. This was suggested to increase the liquid bridge size and the capillary contact between the stacked cores.

8.1 Strongly Water-Wet Conditions

Experiments carried out at strongly water-wet conditions showed that the first core reached the spontaneous imbibition end point before the water entered the fracture. This corroborates the theory of continuity in capillary pressure between a porous medium and an open void like a fracture. The water entered the oil-filled fracture by gravity segregation along the outlet face of the first core. The thickness of this water film was below the resolution of the MRI, (approximately 150µm). The relatively high injection rate (2ml/h) and the small volume of the open fracture caused rapid filling and hence insignificant amount of water was imbibed into the second core before the fracture was totally filled. Figure 8.1 shows different MRI imaging sequences of the dynamic fracture crossing experiment.



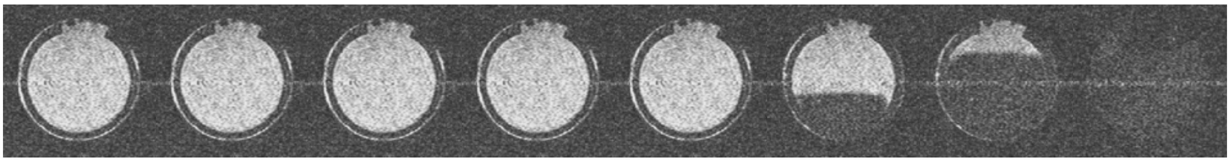


Figure 8.1: a): Water saturation as function of the stack length, b): Water saturation in first core, fracture and second core as function of time and c): MRI image of the oil (white) in the open fracture.

8.2 Moderately Water-Wet Conditions

As mentioned earlier authors like for example Saidi and Stones have suggested that water bridges may establish capillary contact across open fractures. In our experiments, MRI images of open fractures visualized the wetting phase transport through liquid bridges in an initially oil-filled fracture.

At the time of water break through of the first core sample, water droplets appeared on its outlet face. The water break through of the first core happened significantly earlier in the moderately water-wet case than in the strongly water-wet case. The lower water saturation at which the capillary pressure reaches zero, compared to a strongly water-wet situation, allows water to enter the fracture at at an earlier point of time. The significantly longer fracture filling period is explained by the transport of water across the open fracture through the water bridges.

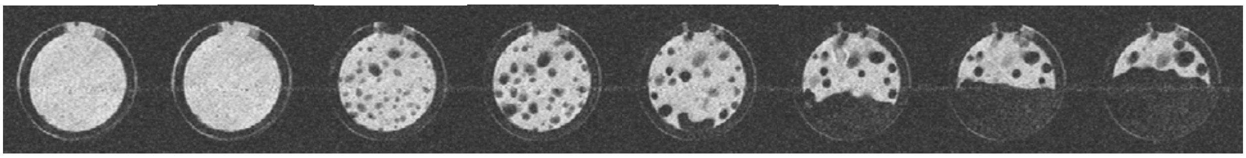


Figure 8.2: MRI images of oil (white) in open fracture during water flood of the moderately water-wet sample.

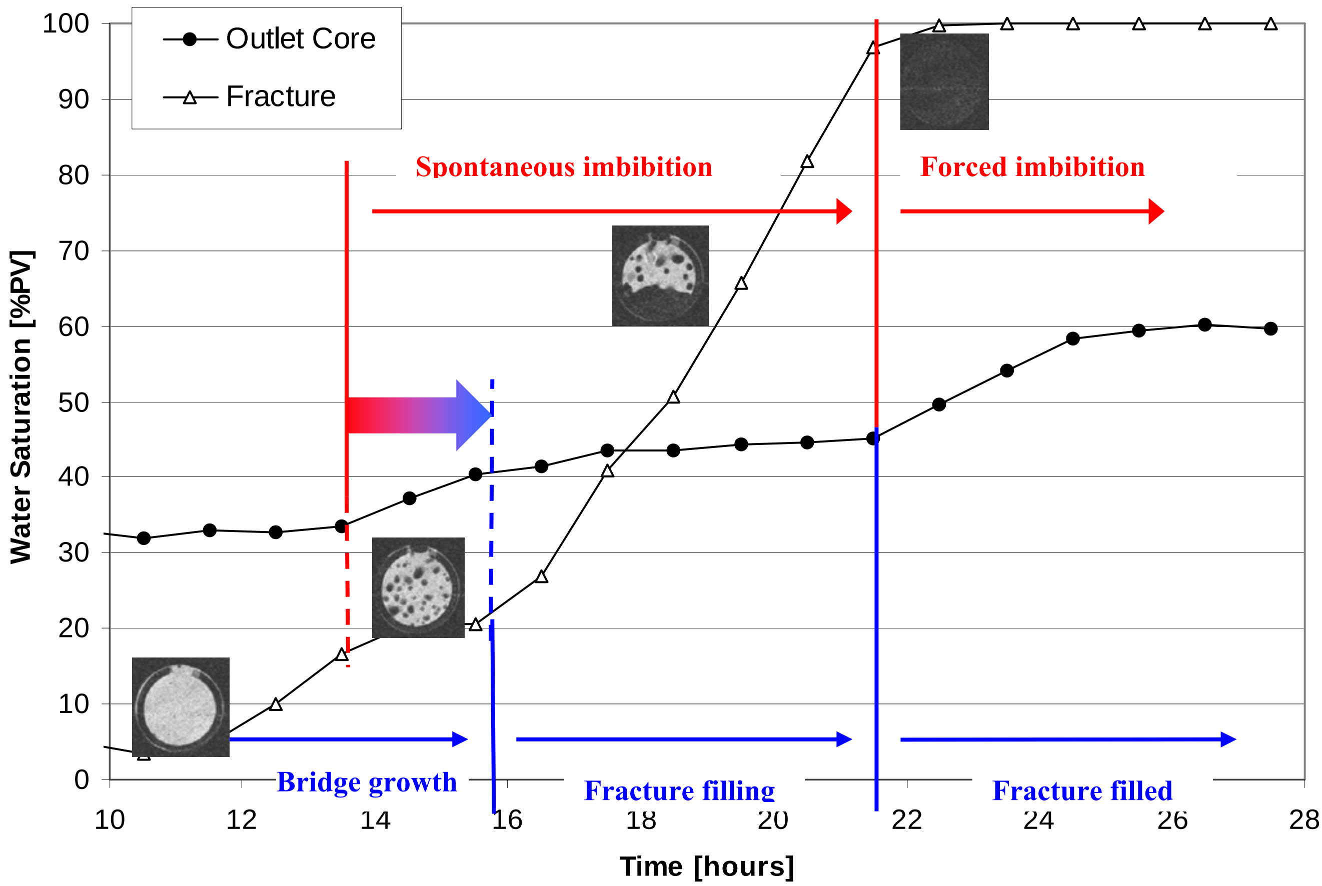


Figure 8.3: Water saturation in fracture and outlet core (Modified Figure 8b in Paper 4)

The dynamics of the water bridges in an open fracture was subdivided into three regimes; *bridge growth, fracture filling* and *fracture filled*. The different regimes are indicated in blue in Figure 8.3 below showing the water saturation of the fracture and the second core plug as function of injection hours.

From 11 to 16 hours after start of water injection the water bubbles on the outlet face of the first core plug grow big enough to touch and connect to the second core plug. This period is denoted "**bridge growth**". The appearance of water in the fracture starts with growth of water droplets on the outlet surface of the first core. At this stage no capillary contact through the water bridges are established yet and the amount of water in the first core plug and in the fracture increases while the second core plug exhibit constant water saturation. Between 13 and 16 hours, 7% (1.1ml) of the pore volume spontaneously imbibed from the fracture into the second core plug *exclusively* through water bridges. This is marked by a broad arrow in Figure 8.3. Analysis of the MRI image obtained at 15.5 hours after start of water injection shows that 29 water bridges of various size covered 20% of the cross section of the fracture. If this is linearly scaled up to a cross section of 1 by 1 meters, it corresponds to 430 000 water bridges.

	Amount	Ø [cm]	Area [cm^2]
Small droplets	17	0.2	0.5
Mediun droplets	10	0.3	0.7
Large droplets	2	0.5	0.4
Total	29		1.6

Fracture area = 8.0cm^2 → droplets cover ca 20%

From 16 to 21 hours after start of water injection the water bridges grow further and start to coalesce and sag to the bottom of the fracture because gravity forces override the surface tension. The fracture is filled with water from bottom up. This is called the "**fracture filling**" period. Although there is no evidence, there is reason to believe that transport of water through the remaining water bridges occurs throughout the entire "fracture filling" period in Figure 8.3.

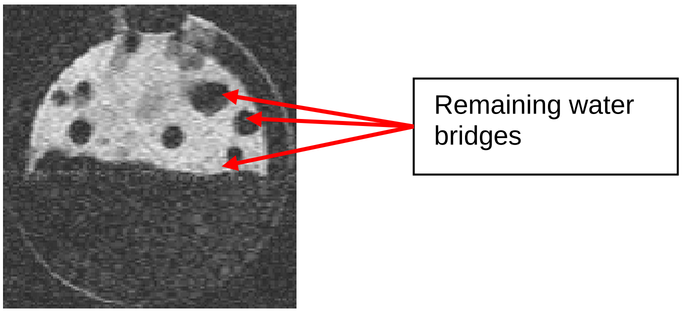


Figure 8.4: MRI image of decane in open fracture at 19.5 hours (Iw=0.6, 2mm aperture)

The last period is when the fracture is **filled** with water and starts hydraulically forcing the water into the second core plug.

Spontaneous and *forced imbibition* mechanisms of the outlet core plug were identified (red in Figure 8.3 above). The imbibition types are recognized from the shape of their dynamic saturation curve, on images of the dynamics of water droplet behaviour and on the injection pressure. In order to verify that *spontaneous imbibition* actually took place from the open fracture and into the second core, the saturation development curve of the second core plug was compared with data from a core plug of similar wettability conditions in an imbibition cell. The imbibition data of the second core plug was scaled by the scaling law of Mattax and Kyte (1962) in order to account for the surfaces covered by the sleeve and the end piece used in the flow experiments. The scaling law was modified by Ma et al. (1995) and given a definition of dimensionless time, t_D:

$$t_D = t\sqrt{\frac{k}{\phi}}\frac{\sigma}{\sqrt{\mu_w \mu_o}}\frac{1}{L_c^2} \tag{8.1}$$

where k is the absolute permeability, ø is the porosity, σ is the oil/water surface tension, μ is the viscosities and L_c is the characteristic length described by:

$$L_c = \sqrt{V_b / \sum_{i=1}^{n}\frac{A_i}{l_{Ai}}} \tag{8.2}$$

where V_b is the bulk volume of the sample, A_i is the area perpendicular to the imbibition direction and l_{Ai} is the distance from A_i to the no-flow boundary. As can be seen from Figure 8.5 the scaled imbibition data from the second core plug in the fracture crossing experiment match the spontaneous imbibition data. Therefore we can assign the change in water saturation in this regime to spontaneous imbibition.

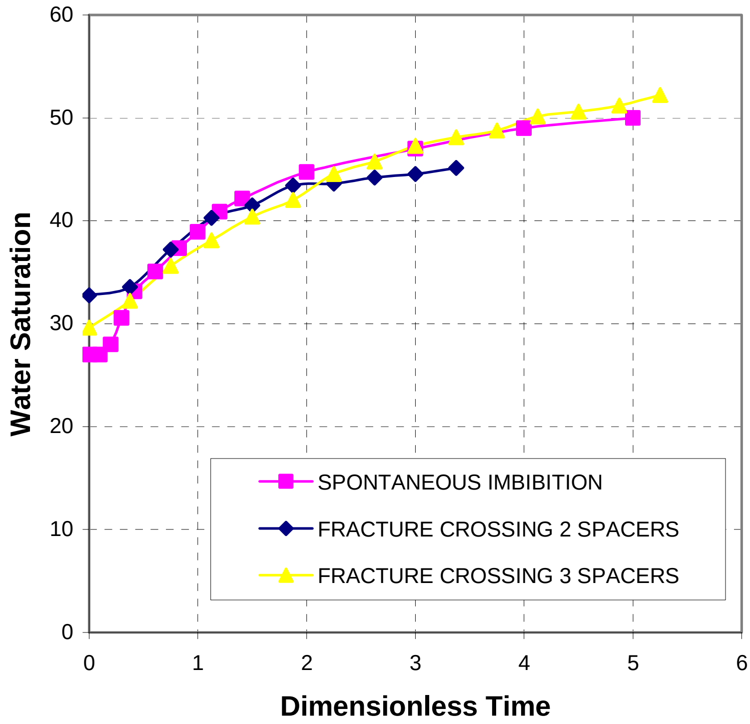


Figure 8.5: Comparison of spontaneous imbibition characteristics using Ma's scaling law.

The *forced imbibition* part of the process is recognized by rapid increase in the injection pressure and oil production. In addition the fracture is water-filled.

8.3 Nearly Neutral Wet Conditions

Although one would expect similar recovery mechanisms at nearly neutral wet as seen in moderately water-wet, we did observe some effects unique at near neutral wettability conditions. Higher pressure is observed at less water-wet conditions reflects that the spontaneous imbibition rate is low and hence the flow regime is more viscous. The relative permeability to water is higher than at strongly water wet conditions and the end point water saturation for spontaneous imbibition is low. Hence a dispersed front will move through the matrix causing an early water break through in the first core. Figure 8.6 below shows decrease in injected water at break-through as the wettability decreases.

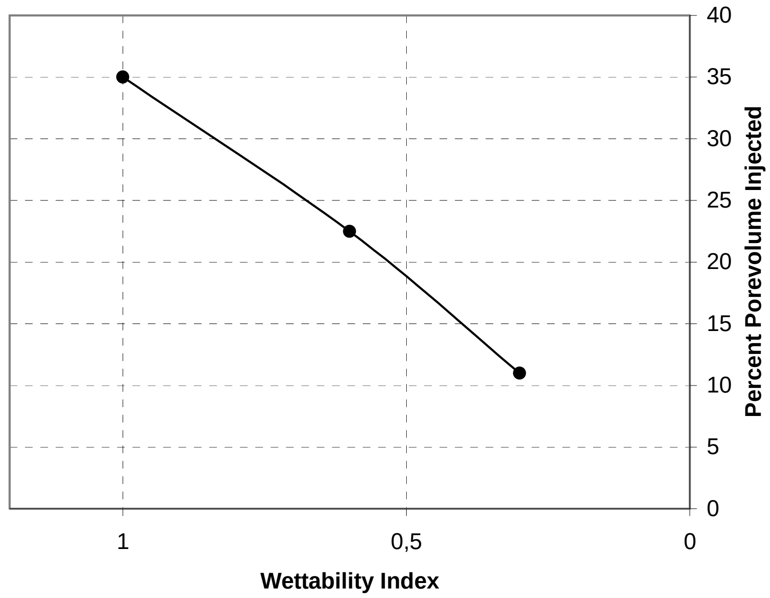


Figure 8.6: Cumulative volume of injected water into the inlet core as water enters the fracture.

After water break-through of the first core several water bubbles were observed on the outlet end face, however, only few bridges formed (Figure 11c in Paper 4). Because the water injection rate is significantly higher than the imbibition rate of the second core plug, the over-supply of water into the fracture caused the bridges to grow too large and sag to the bottom of the fracture.

8.4 Fracture Width

In most publications on fluid flow across fractures, emphasis is on fractures an order of magnitude smaller in aperture than reported in this thesis. Our large block experiments, crossing of fractures in the millimeter scale was observed for lower wettability conditions, hence it was assumed that fractures of smaller aperture also would be crossed. In paper 4 both 2.3 and 3.5mm wide fractures were used to investigate the effect of fracture width. A general understanding is that when the fracture gets above a critical limit, droplets cannot grow across. This will of course depend on the density difference of the two liquids controlling the gravity, the surface tension between the two liquids, the rock wettability characteristics and surface roughness. These tests were performed not because we believe that wide fractures exist in chalk reservoirs, but solely to test the fracture crossing mechanisms.

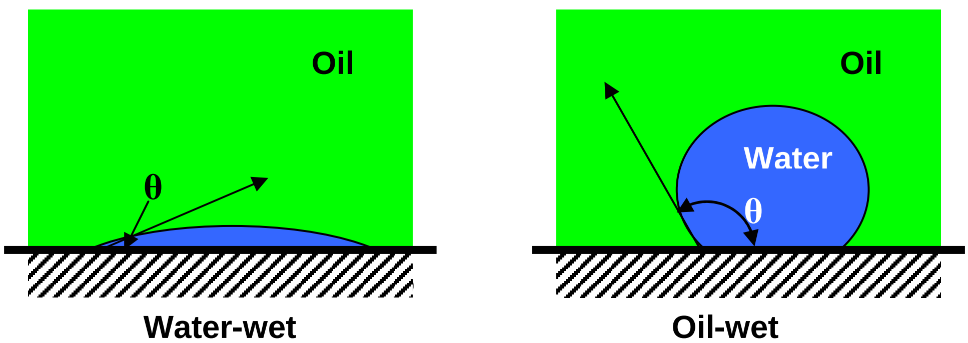


Figure 8.7: Schematic of water droplet shape at different wettability conditions.

8.5 The Presence of an Escape Fracture

All fracture crossing experiments described above use sleeved stacks of core plugs. The water is eventually forced to cross the fracture and enters the next core as long as the water injection proceeds. The experiments do not quantitatively describe the oil recovery as function of wettability, but rather investigates different fracture crossing mechanisms. Hence we decided to add an alternate fracture allowing the water to bypass the second core plug, Figure 8.8. The idea behind this was to test the fracture crossing theory and see if the water phase would establish bridges across an open fracture even if an open path to the outlet was present. This experiment was only run at one wettability condition; Iw=0.3. It was prioritized to compare injection of constant rate with constant pressure, in order to investigate the possibilities of forced imbibition on matrix blocks isolated by fractures.

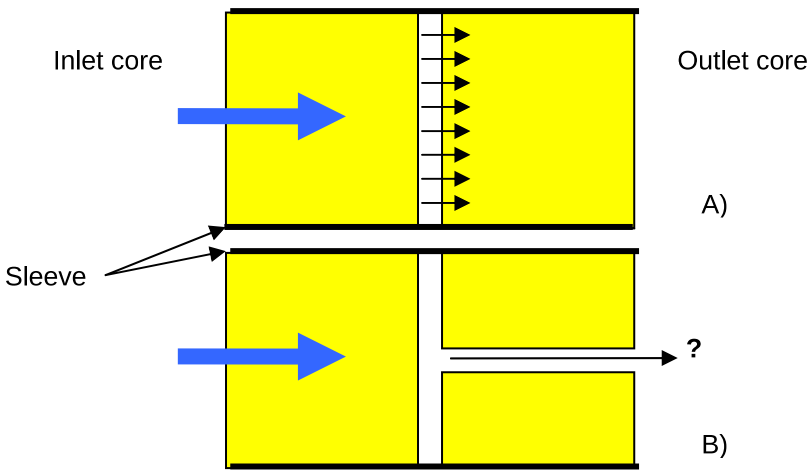


Figure 8.8: Schematic of the escape fracture idea. A) Water forced to enter second core. B) Alternate escape path for the water phase.

The results presented in Paper 6 show that despite the alternate escape path for the water phase, water bridges were formed across the open fracture. The water bridges were stable for days transporting water from the inlet core to the two isolated outlet pieces. This resulted in oil recovery in the outlet cores far exceeding the spontaneous imbibition potential (50 vs. 39%PV respectively). The major difference between the constant injection rate and constant injection pressure was that the differential pressure applied on the system was an order of magnitude higher in the constant rate experiment than in the constant pressure experiment (1 and 10psi/ft). The idea was to see if the water bridges could exert higher pressure gradient on the isolated cores.

There was more than twice the number of water bridges in the constant rate case compared to the constant pressure case. Because the bridges were of similar size in the two cases, the effective area of water bridges was significantly higher in the constant rate experiment. This is explained by the high water flux forced to cross the fracture. However the higher rate of injection and the high number of bridges did not increase the recovery from the two isolated matrix blocks above which was found in the constant pressure experiment. The size of the bridges seemed to be controlled by the wettability of the rock and not by the differential pressure applied across the open fracture.

8.6 Comparison with Large Block Experiments

In Paper 5 the results from the stacked core experiments are compared to parallel work performed on the large blocks. The major advantages of the large block experiments are the more complex network reflecting all of the matrix/fracture interactions under the simultaneous influence of all the acting forces. The interpretation of the history matching of the water floods by numerical simulation is greatly improved by the in-situ fluid saturation information. Experiments reported in Graue and Nesse (2002) show that at moderately water-wet conditions, the ultimate recovery increases with decreasing fracture/matrix permeability ratio. This is not believed to apply for strongly water wet rock where the spontaneous imbibition and the forced imbibition endpoint is the same.

Numerical simulation of the large block water floods at different wettability conditions have developed further knowledge of the recovery mechanisms in fractured chalk. Core plugs receiving similar wettability treatments were used for capillary pressure and relative permeability measurements providing improved input to the simulator. The water floods were history matched with respect to the oil production and water cut as well as the in-situ water saturation dynamics provided by NTI. In order to achieve good matches of the in-situ water saturation dynamics, the representation of the fracture network and the block to block interaction had to be based on the physics controlling this process. The wettability effects could not be achieved by adjustments of the flow functions only. Capillary contact had to be included between the matrix blocks in order to match the experiments. This capillary contact was shown to be dependant on the wettability of the rock. By implementing partial capillary contact in the model between adjacent blocks, improved block-to-block fluid dynamic representation was achieved, Graue et al. (2000a).

8.7 Conclusions on Water Transport Across Open Fractures

- Distinct recovery mechanisms at different wettability conditions have been identified. At strongly water-wet conditions the matrix and the fractures plays two distinct roles in the recovery process. The fractures will be the transport path for the water and oil while the matrix will imbibe water from and expel oil to the surrounding fracture network. However for the less water-wet cases, capillary continuity of the water phase caused the fractured system to act more as a uniform block with less significant boarders between the matrix and the fracture. In synthetic cases like these laboratory experiments, water crossed oil-filled fractures of 2-3mm aperture when the wettability index to water was in the range of 0.2-0.7.
- In fractured oil reservoirs the matrix blocks will be surrounded by fractures with various degree of contact with adjacent blocks. At lower wettability conditions the weak capillary forces will result in poor recovery by imbibition from the surrounding fracture network. The stacked core experiments indicate that capillary contact across open fractures established by water bridges contributes significantly to oil recovery beyond the potential for spontaneous imbibition.
- The findings from the stacked core experiment are supported by the parallel work being performed on large block experiments.

Chapter 9: Applicability and Further Work

9.1 Relevance and Applicability of The Results to the Oil Industry

The applicability of this study to the oil industry has emphasis in two areas. The first being the improved understanding of the aging process during preparation of core plug material for use in special core analysis (SCAL) reflecting predetermined wettability conditions of specific reservoirs. Second, the recovery mechanisms at different wettability conditions have been determined to improve the understanding of multiphase fluid flow in fractured reservoirs and improve the representation of fractures in numerical simulations and thus improve the predictability of oil production.

SCAL is used by the oil companies to gather information on reservoir characteristics as input to their numerical simulators in order to get information on the reservoir and to forecast the production. This is done for economic evaluation of new asset developments as well as for mature fields for production prognosis and future investment evaluations. In order to achieve good results from the SCAL analysis the core plugs have to yield conditions representative for the reservoir under study. For reservoirs other than strongly water wet, restored state core material or outcrop rock analogues is dependent on wettability alteration. The uniformity of the induced wettability condition will be among the criteria deciding whether the results will be representative or not. The aging procedure described in Papers 1 and 2 will provide improved uniformity of the wettability distribution and at the same time be obtained significantly faster than by the conventional submersion technique.

The results from the fracture crossing experiments describe how water is able to cross open fractures when water flooding a fractured low permeable reservoir. Emphasis has been on capturing the effect of wettability, but also parameters like fracture aperture, differential pressure and an alternate flow path have been investigated. The results can be used as improved understanding of water flood performance in fractured low permeability reservoirs at different wettability conditions. One good example is the fracture representation in numerical simulators. On the basis of these qualitative results, improvement in capillary continuity as function of wettability could be included. This would give a more realistic representation of the recovery mechanism based on the physics.

More directly, the results can be used in evaluations of the applicability for water flood as secondary recovery method in fractured chalk reservoirs. It has been shown that in reservoirs like the Ekofisk formation of the Ekofisk field in the North Sea where at moderately water-wet conditions with limited vertical continuity, the response to water flood is almost as good as in the water-wet parts of the reservoir due to a combination of imbibition and viscous forces (Hamon 2004).

It could also be used in evaluation of IOR through wettability alteration using methods like steam or hot water injection, Al-Hadhrami and Blunt (2000) and Masalmeh (2002), surfactant injection, Austad and Milter (1997), or pressure depletion. The results presented in this thesis indicate that a change from oil-wet to only slightly water-wet conditions may yield a significant increase in water flood oil recovery.

8.1 Further Work

Although I see my task “Wettability Effects On Oil Recovery Mechanisms in Fractured Chalk” as completed, this is only a step towards understanding fractured reservoir response to water injection. A natural development of the project would be to look at fractures that are not perfectly machined. Changes in surface area, roughness and contact angle will probably have impact on the flow behavior. Furthermore, the matrix blocks in a real reservoir will have physical contact points with various material conditions. Contact points are often under compression and shear stress and a certain degree of pore network damage is expected. The interplay between stress and fracture transmissibility as function of wettability can be studied with the use of the NTI technique and high spatial resolution MRI.

The transport of connate water through a fractured rock during water injection is crucial when predicting field response like scale potential and reservoir temperature distribution. This is also one of the most important factors when evaluating the potential for improved recovery by chemical or bio assisted water injection.

Even though carbonates in general are more brittle than sandstone reservoir rock the nature of the complex carbonate rock surface makes it more susceptible to wettability alterations, it would be interesting to see what impact different rock material will have on fluid flow across open fractures. In sandstone of Darcy permeability, the matrix/fracture permeability ratio would be increased orders of magnitude compared to the Rørdal chalk. Maybe the small viscous pressure exerted by the water bridges would increase the recovery even further. In such a case, the capillary pressure in the matrix would be significantly lower and the multiphase fracture/matrix interactions could be different.

When it comes to oil wet rock, this theme has been out of the scope of this thesis. The oilfield under study has the range of wettability from near neutral-wet to strongly water wet. However, a great potential of improved recovery is common for this kind of oilfields. A simple water flood of oil-wet fractured low permeable rock will, in theory, only recover the oil contained by the fractures. A good example of this is the Ghaba North field in Oman where extensive water flooding for several years has resulted in oil recovery of 2%.

Another aspect of this study is the use of numerical simulations. It has been shown in this thesis that changes in wettability cannot be sufficient represented by changes in relative permeability and capillary pressure functions. The capillary contact at moderately to nearly neutral wettability conditions has been manually represented by the use of two layers of numerical grid blocks representing the fracture properties. This method applies for simple two dimensional systems as our large block chalk models. For applicability in reservoir simulations the partially capillary contact in the water phase has to be built into the code of the numerical simulator.

Abbreviations

CAT	Computer Assisted Tomography
CPMG	Carr-Purcell-Meiboom-Gill
EOR	Enhanced Oil Recovery
FWL	Free Water Lever
IFT	Interfacial Tension
IOR	Increased Oil Recovery
MRI	Magnetic Resonance Imaging
MWL	Mixed Wet Large
MWW	Moderately Water-Wet
NMR	Nuclear Magnetic Resonance
NPV	Net Present Value
NTI	Nuclear Tracer Imaging
SCAL	Special Core Analysis
SWW	Strongly Water-Wet

Nomenclature

A_i	area of surface i
C_i	population coefficient of exponent i
ft	foot
Iw	amott-Harwey Wettability Index to Water
k	absolute permeability
kr	relative permeability
l_{ai}	distance from Ai to no-flow boundary
L_c	characteristic length
Nt	global time scale ratio
Pc	capillary pressure
S_{or}	residual oil saturation
S_w	water saturation
$S_{w.imb}$	water saturation at end point of spontaneous imbibition
S_{wi}	initial water saturation
t	time
T_2	e
t_D	dimensionless time
t_{fc}	threshold aperture
V_b	bulk volume
α	angle
μ	viscosity
σ	surface tension
φ	porosity
ω	storativity ratio

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Part 3

Papers

List of Papers

Paper 1
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Paper 5
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Paper 6
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