In the Name of God

Analysis, Scaling and Simulation of Counter-Current Imbibition

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The aim of this research is to improve the modelling of oil recovery from water-wet and mixed-wet fractured reservoirs using transfer functions based on experimental data. Counter-current imbibition, a key recovery mechanism in fractured reservoirs was studied in this work.

The first step was to ensure that the experimental results can be explained by conventional modelling of capillary-controlled displacement. Simulations of counter-current imbibition were performed and the results were compared with experimental measurements in the literature.

A study of a wide range of dimensionless equations to scale imbibition recovery in water-wet system was carried out to show that the time scale for recovery is inversely proportional to the geometric mean of the water and oil viscosities for water-wet media.

A dimensionless empirical equation that matched core-scale imbibition experiments was used to derive a transfer function to be used in large-scale simulation. Then simulations of water flow through a single high permeability fracture in contact with a lower permeability water-wet matrix were performed. It was demonstrated that with this transfer function the behaviour of the two-dimensional displacement can be adequately reproduced using a one-dimensional model.

A quasi-static pore-scale network modelling as a novel tool was used to study the physics of imbibition in mixed-wet rocks. It was possible to reproduce the observed dramatic increase in imbibition time as the system changes from being water-wet to mixed-wet. It is shown that in a mixed-wet system spontaneous imbibition is limited to a narrow saturation range where the water relative permeability is
extremely low, leading to recovery rates at least a thousand times slower than for water-wet media. It is suggested that water mobility is the key parameter controlling imbibition rate in mixed-wet rocks. By including the water mobility in the dimensionless time, an analytically supported scaling group is presented that is simple and physically meaningful that can correlate successfully experimental spontaneous imbibition recoveries for different wettability states and for a wide range of viscosity ratios. A study of different dimensionless equations proved the validity of this equation. An empirical correlation that could be used to predict imbibition rates for mixed-wet media at the field scale is also proposed.

Then a field study on a fractured Iranian reservoir was performed to show the impact and application of the study at the field scale. This study showed that wettability has a significant impact on recovery and illustrated that at the field scale a subtle interaction between capillary, gravitational and viscous forces controls recovery and emphasised the importance of an accurate characterisation of wettability and multiphase flow properties.
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Using only water viscosity in the definition of dimensionless time leads to a large scatter in the results from 1D simulations with different oil to water viscosity ratios, $M$, using network model derived data.

Using Zhou et al.\textsuperscript{80} dimensionless time, Eq. (1.11) leads to a scatter in the results from 1D simulations with different oil to water viscosity ratios, $M$, using network model derived data.

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The simulated average matrix water saturation in the 2D simulation scales linearly with the square root of time for a flow rate of 20 cc/hr and reproduces the behaviour of the instantly-filled regime in Rangel-German and Kovscek's\textsuperscript{61} experimental results.
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Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, can be scaled using oil and water mobilities. The quality of scaling is similar to Ma et al.\textsuperscript{52} scaling group, Eq. (1.8).

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Experimental recovery data on Berea cores aged in crude oil for different aging times, $t_{oa}$, from Zhou et al.\textsuperscript{81} (a) Oil recovery by spontaneous imbibition, (b) Oil recovery by water-flooding.

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Fig. 3.13.  Our scaling relation, Eq. (3.9) is used to correlate imbibition recovery simulation of mixed-wet properties of an active Iranian carbonate fractured reservoir.

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Fig. D.1.  Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled using oil and water mobilities whereas water-wet recoveries were successfully correlated for different viscosity ratios, $M$. 
Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, can be scaled using oil and water viscosities but the correlated data does not overlap.

Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, were scaled by including initial water saturation in the dimensionless group but the correlated data does not overlap.

Including square root of water relative permeability in the dimensionless group can be used to scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other.

Including initial water saturation and square root of water relative permeability in the dimensionless group can be used to scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other.

Including initial water saturation, water relative permeability and residual oil saturation in the dimensionless group but the correlated data does not overlap.

Adding the $J$ value computed at initial water saturation to the dimensionless group shown in Fig. D.7 can scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other. The correct value of $P_c$ at $S_{wi}$ to calculate the $J$ value is the challenging part of this equation.
Including $(1-S_{or})$ in the dimensionless group shown in Fig. D.8 can scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, and mixed-wet rock for different aging times, $t_a$, although Bourbiux & Kalaydjian data show a discrepancy. The correct value of $P_c$ at $S_{wi}$ to calculate $J$ value is the challenging point of this equation.

All imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, were scaled but the correlated data does not overlap.

In mixed-wet rocks, $K$ is the water relative permeability at the end of imbibition. However, in water-wet rocks, $k_r$ is defined as the end-point oil relative permeability.

Chapter 4: Analysis of the Impact of Wettability at the Field-Scale

Karanj is one of the major Iranian oil fields.

Reservoir contour map on top of the Asmari formation that shows the entry point of the wells into the formation.

Imbibition relative permeability and capillary pressure for field rock data with $S_{wi}=0.15$. 
Fig. 4.4. Imbibition relative permeability and capillary pressure for field rock data with $S_{wi}=0.435$.

Fig. 4.5. Gas-oil capillary pressure for three field rock types.

Fig. 4.6. Gas-oil relative permeability of three field rock types.

Fig. 4.7. Relative permeabilities of different wettability states data used to test the impact of wettability.

Fig. 4.8. Scaled capillary pressure of different wettability states data used to test the impact of wettability.

Fig. 4.9. History of oil production and injection. This data is the same for all cases. Essentially oil production is fixed as a boundary condition.

Fig. 4.10. Reservoir oil pressure predictions for different wettability states.

Fig. 4.11. The rise of the water-oil contact level is strongly affected by the wettability of reservoir rock.

Fig. 4.12. Fracture gas-oil and water-oil contact levels movement for different wettability states.

Fig. 4.13. The fraction of total oil produced by water displacement for different wettability states.

Fig. 4.14. The fraction of total oil produced by oil expansion for different wettability states.

Fig. 4.15. The fraction of total oil produced by gas influx for different wettability states.
Nomenclature

Latin Letters

\( A_{ma} \) area of a surface open to flow in the flow direction, \( m^2 \)
\( d_{ma} \) distance from the open surface to the centre of block, \( m \)
\( f(\theta) \) wettability factor
\( F_c \) shape factor, \( m^2 \)
\( f_j \) fractional flow
\( g \) fluid conductance, \( m^5 \text{s Kg}^{-1} \)
\( H \) vertical thickness, \( m \)
\( i' \) wettability index
\( K \) absolute permeability, \( m^2 \)
\( k_r \) relative permeability
\( L, L_c \) characteristic length, \( m \)
\( l_{ma} \) distance from the open surface to the no flow boundary, \( m \)
\( M \) viscosity ratio
\( M' \) mobility ratio
\( P \) pressure, \( \text{Pa} \)
\( P_c \) capillary pressure, \( \text{Pa} \)
\( q, Q \) flow rate, \( m^3 \text{s}^{-1} \)
\( r_{wo} \) produced water oil ratio
\( R_\infty \) final oil recovery, \( m^3 \)
\( R \) recovery, \( m^3 \)
\( S \) saturation
\( T \) transfer function, \( s^{-1} \)
transmissibility coefficient, \( \text{Pa}^{-1} \text{s}^{-1} \)

time, \( t \)

dimensionless time, \( t_D \)

Darcy velocity, \( u \)

dimensionless time for apparent contact angle \( \theta \)

bulk volume of matrix (core sample), \( V_{ma} \)

total fluid velocity, \( v \)

width, \( W \)

total oil recovery by imbibition per unit fracture length, \( W^* \)

**Greek Letters**

rate constant, \( \beta \)

porosity, fraction, \( \phi \)

mobility, \( \lambda, \lambda^* \)

oil viscosity, \( \mu_o \)

water viscosity, \( \mu_w \)

contact angle, \( \theta \)

advancing contact angle, \( \theta_{AD} \)

integration parameter, \( \theta^* \)

density, \( \rho \)

interfacial tension, \( \sigma \)

volume rate, \( \tau \)

time required to produce 63% of total oil recovery by imbibition, \( \tau^* \)
Subscripts

\( f \) fracture, flowing
\( i \) initial
\( imb \) imbibition
\( m \) matrix
\( o \) oil
\( p \) phase
\( r \) residual
\( w \) water
\( wf \) water-flooding
Chapter 1 : Introduction

1.1. Background

Hydrocarbon resources provide the main source of energy to the world. Limitations in current oil reserves imply a requirement for improved oil recovery schemes to increase production rate and ultimate recoveries as much as possible. The economic aspect of oil production planning is very important because funding production, injection and transfer facilities and further repairs and work-over require a huge investment. For many countries in the Middle East oil exports represent the main source of income and hence the efficient extraction of reserves is essential for the viability of the whole economy.

Reservoir simulation is one of the essential tools for long-term oil and gas reservoir management. Developing oil and gas fields is a complex and ongoing process. The amount of fluid in place, which is the total amount of each hydrocarbon fluid initially in the reservoir(s), is an important factor in this process. This cannot be known with certainty and the accuracy of its calculation depends mainly on the reservoir data such as rock type properties and distribution, initial fluid distribution and properties, initial reservoir pressure and temperature and so on, prior to the start of production. Ultimate recovery, which is total volume of recoverable hydrocarbon fluid during the whole field production life, is the essential factor for production planning but it can only be estimated. This volume is determined by the efficiency of reservoir natural production drives, artificial schemes and reservoir management. To plan a production program an estimate of the efficiency of that scheme is needed prior to the start of production. This plus the obvious but significant fact that a reservoir can be produced only once, clarifies the need for an accurate tool that accurately predicts the efficiency of each production scheme. Reservoir simulation is one of the most important tools that is widely used for this purpose. Data gathering, reservoir characterisation and definition, history matching and reservoir behaviour predictions for different natural and artificial production plans and finally economic evaluation of all scenarios are the typical sequence of a normal reservoir study. Based on the results of reservoir simulation and other
reservoir behaviour study methods it may be possible to decide the production plan of a field and reduce the risk of the plan.

The limitations of reservoir simulation can be grouped into the accuracy of reservoir data and the simulators. Sophisticated reservoir simulators require a sufficient quantity, good quality and different types of field data to make informed field planning and investment decisions. For this reason, the result of reservoir simulation prior to the start of field production and during early periods of production (many years for huge fields) is the least certain. Also the reservoir production should be started stepwise to find enough reservoir history with the lowest risk. Another important issue regarding reservoir data needed for simulation is that some important data (for instance block height in fractured reservoirs) cannot be accurately measured directly or even indirectly and need to be estimated. Some other types of data are measured in the laboratory and need to be adjusted for reservoir conditions. Finally data gathering is expensive and sometimes operationally difficult. The quality of the reservoir simulator is another crucial factor affecting the simulation results. To simulate a reservoir, the model needs to represent reality as accurately as possible. For this purpose the physics of all important reservoir phenomena must be understood and defined by mathematical equations as accurately as possible. Then these equations must be solved and programmed with the least computational time. Long-term predictions of huge and complex fields with long history may have run times of several days.

Fractured carbonate reservoirs are important oil and gas resources. It is estimated that up to one half of the world’s recoverable oil is in fractured reservoirs. Amarillo and Spraberry in Texas, the Scipio-Albion Trend in Michigan, the Santa Maria district in California, USA, the Asmari limestone in Iran and Iraq and Mara-la-Paz in Venezuela are various types of fractured reservoirs. The action of stresses is the fundamental cause for the generation of fracture in brittle rocks. Brittle rocks include limestone, dolomite, cherts, shales, igneous rocks and metamorphic rocks. Three main causes are considered for most underground stresses are: diastrophism such as folding and faulting as a result of tectonic history of the formation; removal of overburden by erosion; and a reduction in the volume of shales due to loss of water during compaction. Fractured reservoirs can be
grouped into well-fractured, moderately fractured and low-fracture permeability reservoirs\(^\text{74}\). High well productivity index, small horizontal pressure gradient, uniform fluid composition in the fracture through the oil column, uniform gas-oil contact and/or water-oil contact through the fractured segments, high or complete mud loss during drilling of pay zones are typical characteristics of well-fractured reservoirs\(^\text{66,74}\).

Conceptually a fractured reservoir can be considered as a system formed by intercommunicating pores and channels, where the pores form the "matrix system" and the channels the "fracture system". The fracture system contains a very small amount of oil in place compared to the matrix blocks but it has a much larger permeability than the matrix. Oil can move in both fracture and matrix systems and because of this situation these types of reservoir are referred to as "dual systems". Also oil can be exchanged between fracture and matrix. The highly irregular nature of the fracture network and the interaction between matrix and fractures introduces a number of new unknowns to reservoir simulation compared to unfractured reservoirs that are referred to as "single porosity" (matrix only) systems. The modelling of fluid exchange between fracture and matrix around a single block and in a stack of matrix blocks in gas and water invaded zones where saturated blocks are covered by gas or water are new problems specific to fractured reservoirs. Modelling of gravity drainage and oil re-infiltration in the gas invaded zone and water imbibition and oil re-infiltration in the water-invaded zone and convection-diffusion phenomena are challenging topics in these types of reservoirs. From a geological point of view, the correct definition of reservoir fracture network properties is also very important.

The presence of hydrocarbons in the south west of Iran (see Figs. 1.1 and 1.2) was known as early as 3,000 years ago where gas and residual condensate coming from seepages, were burnt in temples\(^\text{66}\). The modern history of oil exploitation in the Middle East was started in Iran following drilling of the first oil well in the Masjid-e-Solyman filed in south west of Iran in 1908.

The pressure exerted from the Arabian peninsula toward the Zagros mountain belt in the south west of Iran acted as a strong shield and made over one hundred folded
Chapter 1

Fig. 1.1. Iran is one of the ancient countries in the world located in the Middle East.

Fig. 1.2. International map of Iran showing some important cities.
anticlines parallel to the Zagros mountains with a geological age from the Oligocene to the lower Cretaceous, Fig. 1.3. The famous Iranian oil-producing formations are Asmari, the Bangestan group and Khami. Most of these are limestone. Some of the Asmari fields have been in production for nearly a century. The presence of extensive fracturing in the Iranian limestone reservoirs leads to uniform gas-oil and/or water-oil levels in similar flanks through most of the reservoirs. The thickness of the producing formation varies considerably from thin formations up to over 1,000 m in the Agh-Jari and Gachsaran giant fields. However the average matrix properties are relatively poor. The average rock porosity ranges from 5-18 percent and the average absolute permeability is in the range of 0.1 to 5 millidarcy.

Fig. 1.3. Folded anticlines parallel to the Zagros mountains in the south west of Iran.

Gravity drainage plays the major role in hydrocarbon recovery from low permeability matrix blocks when their height is sufficient. In fractured reservoirs, the presence of vertical fractures makes the gas-oil or water-oil contacts advance
ahead of the corresponding contacts in the matrix blocks. The difference between the density of the different fluids in fracture and matrix and elevation of the contacts is a driving force for fluids in the matrix blocks to be produced. If the pressure drops below the bubble point, the liberated gas tends to form a secondary gas cap in addition to the primary gas cap and possible injected gas. As the gas zone expands, matrix blocks become surrounded by gas. The pressure difference between fracture gas and matrix oil becomes the main driving force for oil recovery, which is limited by the capillary pressure between two phases. One important phenomenon in gravity drainage is oil re-imbibition. Re-imbibition refers to the re-entering of drained matrix oil into lower matrix blocks, also known as the block-to-block process. The degree of re-imbibition will greatly affect the efficiency of gravity drainage.

Water displacement is another important mechanism of oil production from fractured reservoirs. Water injection is widely used to improve ultimate oil recovery from fractured reservoirs. Access to water resources, especially in off-shore fields, often makes water injection the preferred secondary production mechanism. Imbibition is the name associated with the mechanism of water encroachment into reservoir rock driven by capillary forces. Imbibition is the mechanism of displacement of non-wetting phase by wetting phase. From this definition the most important factor affecting this phenomenon is the wettability of the reservoir rock.

The speed of movement of the water front or the water-oil level in the fractured network of a fractured reservoir is an important issue, which imposes special boundary conditions for the imbibition process. The mechanism of displacement and its related efficiency is different if the matrix block is covered by water or only contacts it from the bottom. In general imbibition can take place by co-current and/or counter-current flow. In co-current flow the water and oil flow in the same direction, and water pushes oil out of the matrix. In counter-current flow, the oil and water flow in opposite directions, and oil escapes by flowing back along the same direction along which water has imbibed. Experimentally this process can be studied by surrounding a core sample with water and measuring the oil recovery as a function of time. Counter-current imbibition is often the
only possible displacement mechanism for cases where a region of the matrix is completely surrounded by water in the fractures\textsuperscript{60,63,73}. The high transmissibility of the fracture network in fractured reservoirs can easily result in counter-current imbibition becoming the main recovery process in the immersed blocks located in the water-invaded zone of the fractured reservoir with an active aquifer or under water injection.

The purpose of this study is a comprehensive review and analysis of counter-current imbibition. As the first step, an analysis of literature is presented with a survey of theoretical, numerical and experimental work regarding imbibition in water-wet reservoir rocks. In this review, I will discuss the nature of this mechanism and factors that influence it. The same sequence will be followed regarding mixed-wet rocks. Then methods used to simulate these phenomena are reviewed and analysed. Finally, I will state the problem and explain how to improve our current modelling capabilities in the light of our analysis of the literature and show the application of the study at the field scale.

1.2. Water displacement in water-wet rocks

In water-wet fractured reservoirs, imbibition can be a dominant drive in the water-invaded zone. Strong capillary forces tend to imibe water as the wetting phase into the matrix blocks and discharge oil as non-wetting phase out of the block. Water injection as a secondary production scheme to increase ultimate recovery especially in water-wet reservoirs has been used for several decades. Many attempts, reviewed below, have been made to understand and define the mechanism of imbibition in water-wet rocks and its impact on field-scale recovery.

Morrow and Mason\textsuperscript{55} have provided a good, recent review of the experiments and theory of recovery of oil by spontaneous imbibition in water-wet and non-water-wet rocks. Their review is centred on developments in the scaling of laboratory imbibition data. Their review of water-wet media also includes theories of imbibition into capillaries and porous media and an analysis of all the important factors that influence the imbibition process and scaling.


1.2.1. Scaling of laboratory imbibition experiments

Scaling laws can be used to predict oil recovery from matrix blocks. Based on this concept, the oil recovery from reservoir matrix blocks can be predicted from tests on small experimental samples. Morrow and Mason\(^5\) stated that the computational efficiency of field-scale simulators can be increased by including imbibition rate in the form of a scaled group in fracture-matrix transfer functions. *This topic will be pursued in this thesis.*

Mattax and Kyte\(^6\) performed a series of imbibition experiments to verify their scaling theory. They used different length (synthetic) Alundum samples for one-dimensional and Weiler sandstone samples for three-dimensional tests. The absolute permeability and porosity of the Alundum samples were in the range of 75-1545 md and 22.3 to 29.1 percent. The absolute permeability and porosity of Weiler sandstone samples were 120 md and 18.1 percent. An 8.5 cp oil and 0.9 cp brine were used in all cases except one, in which the viscosities were increased up to 14 times but the 8.5 to 0.9 oil to water viscosity ratio was maintained. No initial water saturation \(S_{wi}\) was established in the samples. Initial water saturation is present in field situation and so ignoring it in the experiments represents a limitation of the work. The saturated samples were immersed in the brine and imbibition recovery versus times was measured. They presented the following scaling law to predict the oil recovery by imbibition when gravity has no effect:

\[
 t_D = t \sqrt{\frac{K}{\phi \mu_w L^2}} \tag{1.1}
\]

where \(t_D\) is dimensionless time, \(K\) is permeability, \(\phi\) is matrix porosity, \(\sigma\) is interfacial tension, \(\mu_w\) is water viscosity, \(L\) is characteristic length and \(t\) is imbibition time.

The following conditions for both laboratory and reservoir systems must be the same for this equation, (1) shape of the lab core and the reservoir block, (2) water/oil viscosity ratio, (3) the initial fluid saturation, (4) the pattern of water movement in the surrounding fracture, and (5) relative permeabilities as a function of fluid saturation. Further, the capillary pressure of the laboratory and reservoir
systems should be related by a direct proportionality such as Leverett's dimensionless $J$-functions. They correlated their experiments on Alundum and Weiler sandstone samples by this equation. Morrow and Mason stated that these conditions provide a useful starting point in identifying the factors that need to be investigated to predict imbibition recovery but there is strong practical interest in developing correlations with less restrictive conditions.

Eq. (1.1) means that recoveries experiments on cores of different size and with different fluids all lie on the same universal curve as a function of the dimensionless time. It is assumed that in field conditions, the imbibition recovery from each matrix block would also be given by the same function of dimensionless time as the core experiments.

Parsons and Chaney in an attempt to improve scaling laws to include the slowly rising water table in water-wet carbonate rocks, performed experiments on different sized samples and with different rate of rise of the water-oil interface surrounding the rock pillars. They used both outcrop and subsurface samples. To give a highly water-wet condition, the samples were heated for six hours at 400 °C. No initial water saturation ($S_{wi}$) was established in the samples. The samples were square cross sectional pillars 1x1x12 and 4x4x12 inches. Their porosity was between 9 to 18 percent. The fracture aperture surrounding the pillar was $\frac{1}{8}$ and $\frac{1}{4}$ inch respectively. A refined white mineral oil and distilled water were used as liquids. Initially the samples were surrounded by oil in the cell. 24 separate rising water table experiments at a constant temperature of 80 °F were completed. All 24 tests were performed on seven samples. The number of experiments per sample ranged from one to six. After each test, the samples were washed, dried and re-saturated.

Parsons and Chaney tested the Mattax and Kyte scaling law, Eq. (1.1), to match the imbibition tests on water-wet carbonate rocks. They suggested that if gravity is important the following equation should be used:

$$\left(\frac{L \Delta \rho}{\sigma} \sqrt{\frac{K}{\phi}}\right)_{\text{model}} = \left(\frac{L \Delta \rho}{\sigma} \sqrt{\frac{K}{\phi}}\right)_{\text{recovery}}$$  \hspace{1cm} (1.2)

where $\Delta \rho$ is oil-water density difference.
1.2.1.1. Expressions for the shape factor

Shape factor is one of the important issues related to the application of transfer functions. This factor is to include the effect of shape and boundary condition on imbibition recovery\cite{52}.

Du Prey\cite{29} performed imbibition tests to assess the scaling laws and active forces in recovery processes from matrix blocks in fractured reservoirs. To examine the water sweep in a block, counter-current imbibition tests were carried out on single sandstone matrix blocks. All the samples were homogenous with heights ranging from 5 to 13 cm. The oil was a 50-50 mixture of paraffin oil and kerosene. The water was distilled. A constant water circulation was directed to the fissure at the bottom of the block. This flow was reported as either less than or greater than natural imbibition. Saturation was measured by gamma rays through the block on horizontal lines parallel to the fissure. Du Prey\cite{29} concluded based on the experiments that for small blocks, capillary forces dominate and the recovery rate is inversely proportional to the square of the block size (which is in line with the work of Mattax and Kyte\cite{54}), while for large blocks, gravity takes over and the recovery time is proportional to the size of the block (which is in line with Parsons and Chaney\cite{57}).

Hamon and Vidal\cite{38} performed a series of imbibition tests on synthetic homogenous and outcrop heterogeneous water-wet samples to assess the validity of scaling laws. They stated that in homogenous samples, faster imbibition takes place with a decrease in block height and with an increase in exchange area. In all cases of homogeneous porous media where the capillary forces were dominant, they verified that the time for a given oil recovery is proportional to the square of the sample height, in accordance with the work of Du Prey\cite{29} and Mattax and Kyte\cite{54}.

Cuiec et al.\cite{24} described their experimental studies of simultaneous co- and counter-current imbibition tests on relatively small cylindrical laterally-coated low-permeability samples of outcrop chalk. They investigated the effect of variable block height and boundary condition on spontaneous imbibition. The sample heights ranged from 5 to 20 cm with an average porosity of about 40.4 percent and permeability of 2.4 md. They used light refined oil (55 °API) and synthetic brine.
During the test, the sample was immersed in the aqueous phase and oil was produced from the faces covered by aqueous phase.

Their results on samples 20, 9 and 5 cm long showed that imbibition rate was strongly affected by the sample length whereas final oil recoveries were similar. The imbibition rate increased with a decrease in block height. They did a dimensional analysis to check the effect of exchange area and gravity. The result of this analysis showed that when gravity has no effect the recovery time is nearly proportional to $L^2/\sqrt{K}$ where $L$ is block height and $K$ is absolute permeability. This conclusion is in line with Mattax and Kyte\textsuperscript{54} and others\textsuperscript{29,38}.

Cil et al.\textsuperscript{22} to better understand the different characteristics of spontaneous imbibition conducted counter-current water-air and water-oil imbibition experiments on single water-wet blocks surrounded by fractures. They used Berea sandstone cores with porosity and permeability of 20 percent and 115 md respectively. Distilled water as wetting phase and air and decane as non-wetting phase were used. They studied different sized parallelepiped samples where all of the faces were open. The results are shown in Fig. 1.4. The main finding is that recovery time tends to be longer as core size get bigger, in line with the results of previous work\textsuperscript{23,28,36,50}.

![Fig. 1.4. Faster oil recovery by counter-current imbibition with decrease in block height for water-decane imbibition (after Cil et al.\textsuperscript{22}).](image)

To check the effect of different boundary conditions, they step-wise sealed the faces of the core sample, Fig. 1.5. With this sequence, the number of open faces of a cubic core was reduced from initially six to only one and therefore imbibition can
be one dimensional (1D), two dimensional (2D) and three dimensional (3D). The effect of these conditions on the oil recovery of water-oil system is illustrated in Fig. 1.6. They stated that these results prove that imbibition time increases with a decrease in the number of open surfaces and exchange area. Overall these tests show the effect of boundary conditions on the imbibition process.

Fig. 1.5. Core sealing sequence for performing 3D to 1D imbibition experiments (after Cil et al.22).

Fig. 1.6. Recovery data for 3D and 2D counter-current imbibition experiments (after Cil et al.22).

Babadagli et al.9 performed counter-current imbibition tests with different boundary conditions on the single blocks of water-wet sandstone samples, Fig. 1.8. They used kerosene-brine and light crude oil-brine. They concluded that a decrease in exchange area caused by the boundary condition would affect ultimate recovery. The results of their tests show a delay for the start of the imbibition process with
limited open faces and exchange area on each face in both co-current and counter-current experiments, Fig 1.8.

![Diagram of experimental matrix boundary conditions](image)

**Fig. 1.7. Different experimental matrix boundary conditions (after Babadagli et al.9).**

![Graph of oil recovery vs. time](image)

**Fig. 1.8. Co-current imbibition tests for different boundary conditions (after Babadagli et al.9).**

The experimental9,22,24,29,38 results have shown the importance of boundary conditions. Kazemei et al.47 presented the following definition for shape factor:

\[
F_s = \frac{1}{V_{ma}} \sum_s \frac{A_{ma}}{d_{ma}} \tag{1.3}
\]

where \(F_s\) is shape factor \((\text{m}^2)\), \(V_{ma}\) is bulk volume of matrix block \((\text{m}^3)\), \(A_{ma}\) is area of a surface open to flow in a flow direction \((\text{m}^2)\), \(d_{ma}\) is distance from the open
surface to the centre of block (m) and $\Sigma$ is summation over all open surfaces of the block.

They\textsuperscript{47} defined a characteristic length corresponds to this shape factor as follows:

$$L_c = \sqrt{\frac{1}{F_s}}$$  \hspace{1cm} (1.4)

This length would then be used in a definition of dimensionless time, Eq. (1.1), in place of the length $L$.

Ma et al.\textsuperscript{52} to match Hamon and Vidal's\textsuperscript{38} experimental results modified the equation for shape factor (Eq. (1.3)). The new relations were:

$$F_s = \frac{1}{V_{ma}} \sum_x \frac{A_{mx}}{l_{ma}}$$  \hspace{1cm} (1.5)

$$L_c = \sqrt{\frac{1}{F_s}}$$  \hspace{1cm} (1.6)

In Eq. (1.5) $l_{ma}$ is the distance from an open surface (imbibition front) to the no flow boundary. Eqs. (1.3) and (1.5) give the same result for different boundary conditions of matrix blocks except for the case when only one face of the sample is open to flow, Fig. 1.9(a) where $L_c = \sqrt{2}L_s$.

Zhang et al.\textsuperscript{77} presented a series of spontaneous imbibition experiments on Berea sandstone to evaluate the characteristic length, Eq. (1.6), to scale oil recovery for a range of viscosity ratios. They used twelve cores that were cut from Berea sandstone with gas permeability near to 500 md and average porosity close to 21 percent. A synthetic reservoir brine and three oil samples that cover a water-oil viscosity ratios range 4-161 were used as fluids. Similar to many others\textsuperscript{54,57}, no initial water saturation was established in the cores in all experiments. This was a significant omission, since, as we discuss later (Sec. 1.2.4), initial water saturation has a dramatic impact on the imbibition rate. To produce different boundary conditions, the cores were sealed by epoxy as can be seen in Fig. 1.9.
They\textsuperscript{79} used the characteristic length Eq. (1.6) and the geometric mean of oil and water viscosities to correlate all imbibition experimental data for different viscosity ratios, Fig. 1.10.

Fig. 1.9. Different boundary conditions for counter-current imbibition (after Zhang et al.\textsuperscript{79}).

Fig. 1.10. Correlation of imbibition recoveries for systems with different core size, shape, boundary conditions and viscosity ratios (after Zhang et al.\textsuperscript{79}).

Ruth et al.\textsuperscript{63} performed a series of simulations of imbibition in different shaped media and for different viscosity ratios to evaluate the Ma et al.\textsuperscript{52} shape factor,
Eqs. (1.5) and (1.6). They concluded that the Ma et al.\textsuperscript{52} shape factor does not compensate for situations where the incremental volume of the sample does not have the same size at different distances from the open face. In order to include this factor, they\textsuperscript{63} proposed that the distance between any incremental volume and the open face should be weighted with the incremental volume and integrated over the entire volume. For the linear case the resulting equation for the shape factor is:

\[
F_s = \frac{A}{L} \int_0^L Ax \, dx
\]  

(1.7)

where \(A\) is cross sectional area and \(L\) is the length of linear system. For the linear case, the characteristic length from Eq. (1.7) will be \(\sqrt{2}\) times the value calculated by Eq. (1.5).

\section*{1.2.1.2. Modified scaling equations}

Ma et al.\textsuperscript{52} modified the Mattax and Kyte\textsuperscript{54} scaling law to include the effect of non-wetting phase viscosity because their experimental results showed that the imbibition time is proportional to the geometric mean of the water and oil viscosities. Their general scaling law for counter-current imbibition in water-wet rocks where gravity has no effect is:

\[
I_D = I_0 \sqrt{\frac{k}{\phi}} \sqrt{\frac{\sigma}{\mu_w \mu_o}} \frac{1}{L_c^2}
\]  

(1.8)

In this equation \(L_c\) is defined by Eq. (1.6). They\textsuperscript{52} could correlate imbibition data presented by Mattax and Kyte\textsuperscript{54} in Alundum samples and Weiler sandstones, Hamon and Vidal\textsuperscript{38} results in synthetic materials and Zhang et al.'s\textsuperscript{79} results in Berea sandstones with different boundary conditions, Fig. 1.11. This equation can simulate oil recovery by counter-current imbibition in water-wet rocks. It is important to know whether the current transfer functions in dual porosity models can match this equation. In this thesis we also evaluate this equation for a wide range of viscosity ratios and against other available experimental imbibition data.
Several authors have attempted to match the imbibition recovery as a function of time (or dimensionless time) to simple closed-form analytical expressions. Arnofsky et al.\textsuperscript{6} first proposed that oil recovery by spontaneous imbibition as a function of time could be modelled by a simple exponential function:

\[ R = R_\infty (1 - e^{-\lambda t}) \]  

where \( R \) is the recovery, \( R_\infty \) is the ultimate recovery and \( \lambda \) is a rate constant. This equation is based on two assumptions: (1) the recovery is a continuous function of time; and (2) none of the properties that determine the rate of convergence change.

Fig. 1.11 shows that recovery as a function of time for a variety of experiments on different water-wet samples falls on a single universal curve as a function of the dimensionless time, \( t_D \), Eq. (1.8)\textsuperscript{52}. These results with different boundary conditions all scaled onto the same curve that was reasonably well fitted by the following empirical function:

\[ R = R_\infty (1 - e^{-\alpha t_D}) \]  

where \( \alpha \) is a constant that best matches the data with a value of approximately 0.05\textsuperscript{52} – see Fig. 1.11.
Zhou et al.\(^\text{80}\) reported experimental results of counter-current imbibition on water-wet cylindrical samples of a diatomite outcrop with very high porosity and low permeability using different wetting/non-wetting viscosity ratios to investigate the effect of this factor on oil recovery and to validate their own scaling relation. The advance of the wetting phase was monitored using a single shot of whole core using CT scanning. The samples had a height of 9.5 cm and a 2.5 cm diameter with a porosity around 70 percent and a permeability about 6 md. They used n-decane and Blondol as the oil phase with a viscosity ratio of nearly 20 and also air as the non-wetting phase. Water as wetting phase was introduced from the top of the cores by pumping and flowed out with produced oil from the end-cap in water-oil imbibition tests.

The recovery rate and ultimate recovery decreased with increase in the non-wetting phase viscosity. They\(^\text{80}\) were able to correlate all the imbibition data for a wide range of mobility ratios with their scaling relation:

\[
t_D = t_i \sqrt{\frac{K}{\phi \alpha c^2 \sqrt{\lambda^*}} \frac{1}{\sqrt{M^*} + \frac{1}{\sqrt{M^*}}}}
\]  

(1.11)

where \(\lambda^*(=k^*/\mu)\) defined as a characteristic mobility for the wetting and non-wetting phases and \(M^*(=\lambda^*_w/\lambda^*_n)\) defined as a characteristic mobility ratio. They used end-point relative permeabilities to calculate \(\lambda^*_n\) and \(M^*. \) In this thesis we will evaluate this equation for a wide range of viscosity ratios.

Other equations have been proposed to match imbibition recovery. Viksund et al.\(^\text{75}\) analysed several imbibition data sets and showed that experimental data for very strongly water-wet Berea sandstone with zero initial water saturation were matched by :

\[
R = R_\infty [1 - \frac{1}{(1 + 0.04t_D)^{1/3}}]
\]  

(1.12)

with \(t_D\) given by Eq. (1.8).
Terez and Firoozabadi\textsuperscript{71} modified Eq. (1.9) to include co-current imbibition in the matrix transmissibility equation. They considered total imbibition oil recovery ($R_{\infty}$) as sum of ($R_1 + R_2$) where $R_1$ and $R_2$ are final oil recoveries due to co- and counter-current imbibition and hence changed the equation to:

$$R(t) = R_{\infty}(1 - Re^{-\lambda_1 t} - Re^{-\lambda_2 t})$$  \hspace{1cm} (1.13)

Gupta and Civan\textsuperscript{36} presented a general exponential equation for oil recovery by water imbibition. They suggested that oil produced by imbibition composed of three irreversible processes (dead-end pore space, network of interconnected pore channels and fracture interface) acting in series. Their equation is:

$$1 - a_1e^{-\lambda_1 t} - a_2e^{-\lambda_2 t} - a_3e^{-\lambda_3 t}$$  \hspace{1cm} (1.14)

where $a_1 + a_2 + a_3 = 1$. This equation will lead to Eq. (1.9) for a special case of rapid transfer of oil from matrix/fracture interface to the fracture network and no contribution of dead-end pores (i.e. $\lambda_2 >> \lambda_1$ and $\lambda_3 = 0$).

In this thesis we validate the scaling equations for different water-oil viscosity ratios using detailed simulation.

1.2.2. Imbibition patterns

Imbibition can take place by co-current and/or counter-current flow\textsuperscript{2,18,38,40,57,59}. When invading water and producing oil flow in the same direction, the flow is co-current whereas when these two flow in opposite directions, the flow is counter-current.

Bourbiaux and Kalaydjian\textsuperscript{18} performed co-current, counter-current and simultaneous co- and counter current spontaneous water-oil imbibition tests on single block samples of strongly water-wet sandstones at laboratory conditions, Fig. 1.12. The samples were laterally-coated and had a parallelepiped shape (61×21 mm cross section dimensions and 290 mm height) with an average porosity of 23.3 percent and permeability range from 118 to 137 md. They used a light
refined oil (55 °API) and synthetic brine. The initial water saturation was 40 percent.

In the dominant co-current flow case, the brine saturation profile measurement showed that a brine-oil front moved regularly from the lower to the upper end with decreasing slope with time due to reduction of gravity forces. In the pure counter-current case, the initial smooth front became flat as it progressed towards the bottom of the sample, Fig. 1.13. In the combined co- and counter current case, two fronts progressed at similar speed from each sample end toward the centre.

Fig. 1.12. Different experimental boundary conditions.
Fig. 1.13. Saturation profiles measured during counter-current imbibition.
(after Bourbiaux and Kalaydjian\textsuperscript{18})

One of the important results of their tests is that the rate of counter-current oil imbibition is much slower than that of co-current imbibition, Fig. 1.14. For example, 90 percent of the oil recovered in counter-current flow after 92 hours, compared with 23 hours for co-current imbibition. In their test, the ultimate recovery of counter-current flow was about 8.5 percent less. The authors concluded that this point needs more investigation to discover whether local heterogeneities are the origin of this difference or not. The front reached the bottom of the sample in the pure counter-current case when only 50-55 percent of ultimate recovery was produced whereas for the co-current case 70-75 percent of ultimate recovery was produced at this stage. This situation will result in smaller capillary pressure as the driving force in the case of pure counter-current. Also the movement of both oil and water in opposite directions during counter-current imbibition will lead to a
lower total mobility than in co-current flow. Due to these facts, counter-current imbibition is slower than co-current imbibition.

Based on numerical simulation they\textsuperscript{18} inferred that the relative permeability for counter-current flow is about 30 percent less than that of co-current flow in these tests, Fig. 1.15. Finally, they reported that water-flooding the samples after each test yielded no extra recovery. \textit{This means that the main drive here was imbibition as a result of capillary forces and the samples were strongly water-wet.}

\textit{Bourbiaux and Kalaydjian}\textsuperscript{18} used realistic fluids and their experiments were in a sandstone rock with an initial water saturation. In this thesis we will use these experimental data in our simulations to evaluate scaling laws and imbibition patterns.

![Fig. 1.14. Imbibition oil recovery for different experimental set ups. (after Bourbiaux and Kalaydjian\textsuperscript{18}).](image)

![Fig. 1.15. Co- and counter-current relative permeability curves.](image)

The results of Bourbiaux and Kalaydjian's work\textsuperscript{18} agree with Parsons and Chaney\textsuperscript{57}, Iffly et al.\textsuperscript{40}, Hamon and Vidal\textsuperscript{38}, Cuiec et al.\textsuperscript{24} and Pooladi-Darvish and Firoozabadi\textsuperscript{59} who all studied the efficiency of co-current imbibition.
Parsons and Chaney\textsuperscript{57} in their experiments observed that oil produces both above (i.e. co-current imbibition) and under (i.e. counter-current imbibition) the water-oil interface. Although they could not determine the exact quantity of oil recovery for each regime, due to relatively higher co-current production rate, they stated that “it is probably easier for the oil to produce into the fracture above the fracture water table because of the resistance of the water-oil interface between the fracture water and oil saturation in the rock”. Another interesting result from their work is finding different recovery curves for different rates of water rise (Fig. 1.16).

They could not find a consistent trend between various rates of water-oil interface rise and oil recovery and seem to relate these to possible experiment errors\textsuperscript{57}. Analysis of Fig. 1.16 shows a general trend of increase in oil recovery rate with a decrease in the rate of water table rise. This means that most of the oil is produced from above the interface and by co-current imbibition, which is also in accordance to their first observation. This experiment shows that co-current displacement where oil is recovered above the fracture water table is faster than counter-current imbibition.

Fig. 1.16. Effect of different rising water table on imbibition recovery (after Parsons and Chaney\textsuperscript{57}).

Iffly et al.\textsuperscript{40} performed a large number of imbibition tests on preserved reservoir rock samples to find out the effect of many variables on the imbibition kinetics and ultimate recovery. Most of the samples were composed of clay silt generally
unconsolidated with porosity range from 10 to 35 percent and absolute permeability from 30 to 2000 md. Some experiments were also carried out on 30 percent average porosity and 50 md average permeability consolidated siltstones. The samples were set up vertically and their opposite ends were put in contact with either water or field oil (naphtenic type 27.5 °API) or else they were kept closed, see Figs. 1.17 and 1.18. These different experimental schemes enable study of the influence of boundary condition, contra-flow and end-effect on the oil displacement.

Recovery curves for different boundary condition are illustrated in Fig. 1.19. It is clear that for test E, that is co-current imbibition, ultimate recovery and also rate of recovery is higher than the rest. Analysis of the experimental set up in Fig. 1.18 shows that there is a head of water at the bottom of the sample (water is not just in contact with the sample) therefore this recovery is due to a combination of capillary and gravity forces. In case A, both co- and counter-current imbibition were active but because counter-current flow dominates both recovery rate and ultimate recovery is less than co-current imbibition. This result agrees with the work of Parsons and Chaney and Bourbiaux and Kalaydjian.

![Diagram](image)

Fig. 1.17. Different imbibition experimental set ups (after Iffly et al.40).
Hamon and Vidal\textsuperscript{38} arranged different boundary conditions for single blocks with variable heights so that co-current and counter-current imbibition was dominant as well as a combination of them, Fig. 1.20. They concluded that the boundary condition on the matrix block has a strong effect on the oil recovery rate but ultimate oil recovery appears to be independent of boundary condition for water-wet rocks.

\begin{center}
\textbf{Fig. 1.18.} Schematic of the experimental set ups.
\end{center}

\begin{center}
\textbf{Fig. 1.19.} Imbibition recovery for various experimental set ups.
\end{center}

\begin{center}
(\textit{after Iffly et al.}\textsuperscript{40})
\end{center}

\begin{center}
\textbf{Fig. 1.20.} Schematic diagram of the different experimental boundary conditions (\textit{after Hamon \& Vidal}\textsuperscript{38}).
\end{center}
Cuiec et al.\textsuperscript{24} investigated the effect of boundary conditions on imbibition. Three different boundary conditions were used: (1) laterally-coated vertical sample; (2) vertical sample coated laterally and closed lower face; and (3) same as (1) in a horizontal position. Final recoveries were reported to be the same for all cases but imbibition rate was reduced slightly when the sample was positioned horizontally. The authors mentioned that spontaneous imbibition in this sample is controlled by a counter-current flow mechanism.

Rangel-German and Kovscek\textsuperscript{61} investigated the rate of fracture to matrix transfer and the pattern of wetting fluid imbibition as a function of the rate of water propagation in the fracture using CT scanning to detect fluid saturation in the bottom fracture of a water-wet single cubic block in a water-air system. Some oil-water experiments were also conducted to verify qualitatively the results of the air-water system.

Experiments with different flow rates and fracture apertures illustrate two different fracture flow regimes. Images of saturations after 0.32 pore volume (PV) of water imbibed into the core are illustrated in Figs. 1.21 and 1.22. Both systems had the same injection rate. The only difference was in their fracture aperture that was 0.1 mm and .025 mm respectively. A wide fracture leads to relatively slow water advance through the fracture due to larger volume of the fracture that took a finite time to be filled by water. This condition leads to a clearly two-dimensional matrix imbibition pattern. On the other hand, the narrow fracture leads to quick water advance due to smaller fracture volume and a one-dimensional matrix imbibition pattern. The authors named these two patterns as "filling-fracture" and "instantly-filled" regimes\textsuperscript{61}. They\textsuperscript{61} stated that water advance in a horizontal fracture is controlled by the interaction between the matrix and the fracture. In the instantly-filling regime the flow is strictly counter-current. They stated that imbibition recovery in the filling-fracture regime can be scaled with time, Fig. 1.23 whereas in the instantly-filled fracture regime recovery can be scaled with the square root of time, Fig. 1.24.
Fig. 1.21. CT saturation image in "Filling-fracture regime". White shading indicates water and dark shading indicates air.
(after Rangel-German and Kovscek\(^6\)).

Fig. 1.22. CT saturation image in "Instantly-filled fracture regime".

Fig. 1.23. The average water saturation in the rock scales with time in the "filling-fracture" regime (after Rangel-German and Kovscek\(^6\)).

Fig. 1.24. The average water saturation in the rock scales with the square root of time in the "instantly-filled fracture" regime (after Rangel-German and Kovscek\(^6\)).
In this thesis we will investigate these two regimes through simulation. The effect of fracture saturation change on matrix imbibition patterns was also tested by Pooladi-Darvish and Firoozabadi\textsuperscript{59} and Lee and Kang\textsuperscript{49}.

Pooladi-Darvish and Firoozabadi\textsuperscript{59} reported a wide range of water injection and spontaneous counter-current imbibition experiments on water-wet fractured porous media comprising separate single blocks and a stack of blocks from one sandstone (case a) and two chalks, as shown in Fig. 1.25. The porosity and permeability of sandstone samples were 620 md and 22 percent whereas permeability of chalks was in the range of 2-5 md with porosity near to 30 percent. They used a visual core-holder and normal-decane as the oil phase and synthetic brine as the wetting phase. The main purpose of their study was the investigation of the effect of advancing fracture water-oil level (FWL) on water displacement and oil recovery.

In their experiments, when the water injection rate increased, the FWL rose faster, this created a larger exchange surface between the matrix and fracture water and hence an increase in oil production due to more water imbibition. In this situation oil had the possibility to produce through the one-phase region occupied by oil around the block (i.e. by co-current flow). As water injection increased further, the block was surrounded by water very quickly, which forced the oil to be produced through a two-phase region, and only by counter-current flow.

The fracture aperture was in the range of 150-200 $\mu$m in the water injection tests and about 10 mm in the counter-current tests. Although the fracture aperture in this case is high, the fracture volume is only 0.5 percent of total PV. The authors used this condition for a better measurement of level change and hence imbibition rate, but more important is that this situation is near to the reality of fractured reservoirs. In some experiments, the produced oil-droplets could be easily removed from the surface of the sample by the flow of water or by increasing their volume in the wide fractures. In some experiments\textsuperscript{10}, the total permeability of the system was not representative of fracture and matrix volumes.
The experimental results of the effect of (one low, two similar moderate and one very high) injection rate on the rate of rise of FWL in the stack of three sandstone blocks are shown in Fig. 1.26. The horizontal lines show the location of horizontal fractures. Careful study of Fig. 1.26 suggests that the velocity of the FWL seems to increase after the level passes a horizontal fracture after which the slope seems to decrease.

The authors concluded that this happens because in this situation water covers all faces of the lower block and oil production decreases due to counter-current flow, leaving more water to rise in the fracture. Another explanation may be that when water touches the upper blocks, it takes time to make enough exchange area between the matrix and the water. Within this period water tends to rise instead of penetrating into matrix blocks and so will rise in the fracture and with this rise provides more exchange area as well.
The experimental results for three water injection rates in a single cubic block with all faces surrounded by fractures is illustrated in Fig. 1.27. Breakthrough recovery decreased sharply with an increase in injection rate. At low injection rate, no oil production was observed under the FWL and very little oil was produced after breakthrough which means co-current imbibition was dominant in this case. At a moderate injection rate, while the FWL was rising, small droplets of oil were visible forming on the matrix surface and then flowing towards the FWL indicating limited counter-current imbibition. At a high injection rate, it was observed that small oil droplets were formed on the rock surface and also underneath the block. These blobs flowed toward FWL. The FWL in these tests initially rose fast and then stopped rising or rose very slowly. From recovery for moderate and high water injection rates and also two counter-current imbibitions, Fig. 1.28, it can be concluded that the co-current imbibition rate is much faster than the counter-current imbibition, although the initial counter-current imbibition rate is slightly faster because of the greater exchange area.

Fig. 1.27. Recovery vs. pore volume (PV) injected for experiments on a single chalk block (after Pooladi-Darvish and Firoozabadi59).

Fig. 1.28. Recovery vs. time for experiments on a single chalk block (after Pooladi-Darvish and Firoozabadi59).
The effect of different injection rates on the four rows and three columns configuration of chalk cubic blocks is illustrated in Fig. 1.29. The sequence of initial fast rising followed by declining FWL when it passes a horizontal fracture can be better seen in Fig. 1.29. There were some interesting observations in these experiments. At low injection rates, before breakthrough, a wet area above the FWL could be seen on the rock surface indicating that oil was produced from just above the FWL into the fracture i.e. by co-current imbibition. The distance between the water-front on the rock surface and FWL reduced to zero when the level reached to the top of each block indicating a delay of water flow from one block to the next block located above the horizontal fracture. They inferred that before breakthrough, oil recovery behind the FWL increases with injected pore volume and concluded that in fractured porous media, the rocks behind the FWL may continue to imbibe water and produce oil.

![Fig. 1.29. Fracture water level for experiments on a stack of blocks (after Pooladi-Darvish and Firoozabadi).](image)

The authors finally concluded that depending on the injection rate both co- and counter-current imbibition could be active. Before a block is fully covered by water, the dominant recovery mechanism is co-current. As the injection rate increases, the rate of recovery increases due to an increase of exchange area between matrix and water. With further increase in injection rate, which causes earlier water breakthrough, the portion of oil to be produced by counter-current imbibition increases. Their experiments and conclusions would have been more convincing if they had investigated the different degree of capillary continuity between the blocks in the columns through wetting layers around grain-to-grain contacts and the effect of these conditions on imbibition recovery rate and efficiency.
Lee and Kang\textsuperscript{49} performed water injection tests through artificially fractured samples of Berea sandstone that initially were saturated with oil to study the effect of variable fracture aperture in water injection. They observed that oil recovery efficiency and breakthrough time decreased with increasing injection rate, Fig. 1.30. Although they did not present any clear relationship between fracture tortuosity and asymmetry, they concluded that oil recovery in fractured reservoirs is significantly affected by fracture morphology as well as the water injection rate and that this effect becomes more pronounced as the injection rate increases. Their conclusion regarding breakthrough time seems to be correct but recovery curves still show continuous recovery which may converge to a similar ultimate recovery for all cases after a long time. Overall their results show the effect of injection rate and fracture capacity on the matrix imbibition process.

![Cumulative oil recovery curves](image)

Fig. 1.30. Cumulative oil recovery curves for 650 md samples for different injection rates (after Lee and Kang\textsuperscript{49}).

### 1.2.3. Effect of viscous forces on imbibition

The effect of viscous forces on ultimate recovery of strongly water-wet rocks where water rapidly can imbibe into the rock is an issue in the investigation of imbibition processes. Do viscous forces affect the rate and ultimate recovery of imbibition in these rocks?

Babadagli\textsuperscript{8} performed a set of experiments to study the effects of injection rate and fracture configuration on capillary imbibition in fractured porous media. The samples used in the experiments were an out-crop rock sample, a two-dimensional glass bead pack and fractured Berea sandstones. The samples were placed
horizontally to minimize the effect of gravity. Water was injected into the fracture and oil and water were produced from the end of the fracture. The water injections were very high relative to the speed of fracture flow in the reservoir and cover a range of .02 to 1 cc/min. The ratio of viscous forces to the capillary forces was increased up to 100. The high fracture/matrix permeability ratio, water injection rates and viscous forces to capillary forces ratios in the experiments ensured that the oil recovery occurred only by capillary imbibition and viscous forces were only significant in the fracture. Therefore an increase in injection rate will not lead to higher recovery in water-wet fractured rocks. However, Gautam and Mohanty concluded that an increase in fracture flow in wide fractures (width≥ 4 mm) will increase imbibition recovery.

Tang and Firoozabadi performed a series of water injection and spontaneous imbibition experiments on single cylindrical blocks and a stack of blocks for a strongly water-wet Kansas chalk outcrop. Normal decane and synthetic brine were used as liquids. Samples had a porosity and permeability near to 30 percent and 0.5 md respectively. Single block dimensions were 5.1 cm diameter and 5.2 to 6.6 cm length. The stacked block was consisted of six single blocks and totally had a diameter of 8.5 cm and total length of 104.7 cm. Fracture apertures were in the range of 150-250 μm, Fig. 1.31. In the single block test water was injected directly to the one end of horizontal block and oil produced from the opposite end. Water was injected from bottom of the vertically positioned stack into the fracture system and oil was produced from the top.

The results of spontaneous counter-current imbibition tests and various constant inlet pressure water injection rates in single blocks are illustrated in Fig. 1.32. It is interesting that the final oil recovery was not influenced by pressure gradient, which means viscous forces did not affect residual oil saturation for strongly water-wet chalk in these tests. This is in line with the results from Babadagli.
Fig. 1.31. Configurations of Kansas outcrop chalks used in the experiments (after Tang and Firoozabadi).  

The effect of pressure gradient on recovery for a stack of water-wet blocks is illustrated in Fig. 1.33. Three constant injection rate tests were performed. The results indicate that an increase in injection rate did not lead to a change in production rate and final oil recovery, but led to a decrease in breakthrough times.

Fig. 1.32. Effect of pressure gradient on oil recovery by water injection: strongly water-wet, configuration A.  

Fig. 1.33. Effect of pressure gradient on oil recovery by water injection: strongly water-wet, configuration B. (after Tang and Firoozabadi).

Babadagli and Ershaghi performed unsteady (water-oil displacement) and steady-state (simultaneous flow of a predetermined ratio of water and oil)
two-phase flow experiments as well as static spontaneous imbibition tests on three different rock types with various configurations and measured the saturation profiles using CT scanning. They used two low permeability (0.1 to 4 md) sandstone and chalk samples and high permeability sandstone (280 to 300 md) samples. The samples were cut with a saw to generate different fracture configurations, Fig. 1.34. The porosity of cylindrical samples ranged from 10 to 22 percent. Kerosene and synthetic brine were used as liquids.

Based on the results of their tests on Colton sandstone, an increase in injection rate of the wetting phase in the fracture will reduce the rate and volume of oil extraction from the very low permeability matrix while the composite permeability of the system is very high in the range of 8 to 20 Darcy. A typical water saturation profile as scanned by CT is presented in Fig. 1.35. In their experiments, the total permeability of the system (matrix plus fracture) was increased with an increase in injection rate and the effect of low matrix permeability is ignored. The total system permeability is a function of both fracture and matrix permeabilities.

It seems that increases in injection rate into the fracture network of a strongly water-wet rock not only does not increase the ultimate recovery but also it may lead to a decrease in imbibition rate and possibly ultimate recovery because an increase in injection rate will result in rapid surrounding of matrix blocks and a
change of mechanism from co-current imbibition to less efficient or less rapid counter-current flow. In this thesis we will evaluate the effect of viscous forces on imbibition recovery in water-wet rocks.

1.2.4. Effect of initial water saturation on imbibition

Morrow and Mason\(^5\) in their review stated that the effect of initial water saturation is not predictable because the presence of water reduces capillary pressure but increases the mobility of the invading water. They also mentioned that the variation of imbibition rate either way was within an order of magnitude.

Du Prey\(^2\) reported the water sweep in the block of one of the tests in a block with height of 13.2 cm, thickness of 3.9 cm and length of 13.9 cm. This block had a porosity of 14 percent and a permeability of 31 md. He stated that when there was no initial water saturation, displacement occurred by penetration of a tongue of water into the heart of the block. Water entered into the centre of the block and then developed in all directions from this position. When there was initial water saturation in the sample that is the realistic situation in the reservoir, the water saturation increased uniformly throughout the volume of the block. When the imbibed volume increased, the saturation profiles became more regular. The difference between these two patterns of water propagation inside the block may explain the reason that lead to different imbibition rates in similar samples with and without initial water.

Cil et al.\(^2\) presented the effect of different initial water saturation on oil recovery by counter-current imbibition. The results are shown in Fig. 1.36. This experiment was carried out to see the validity of using zero initial water saturation samples. They concluded that initial water saturations ranging from zero to 20 percent do not have significant effect on recovery rate in their experiments but the shape of the recovery curve is considerably affected at higher \(S_{wi}\). The increase in imbibition rate at high \(S_{wi}\) seems to be related to the fluid distribution.

Akin and Kovscek\(^1\) performed spontaneous co-current imbibition water-air and water-oil experiments on single blocks of outcrop of high porosity, low
permeability, homogeneous and strongly water-wet samples of diatomite at 20 °C where saturation changes were monitored using CT scanning. The porosity and permeability of samples were nearly 65 percent and 6 to 9 md. De-aerated water and n-decane were used as the liquids. For comparison some tests were carried out using Berea sandstone samples. Water-oil tests were performed with and without initial water saturation.

![Graph of Recovery vs. Time](image)

Fig. 1.36. Effect of initial water saturation on imbibition recovery for water-decane imbibition (after Cil et al. 22).

A saturation profile for a sample without initial water showed an initial spherical flow period followed by a strong and relatively sharp displacement front. Based on this result, they stated two conclusions: (1) during spontaneous imbibition pores of all sizes fill simultaneously; and (2) large pores are interconnected to small pores in the complex network structure of diatomite. In experiments with non-zero initial water saturation samples, a sharp and clear front was not observed. The results of similar tests on non-zero initial water saturation samples of high permeability Berea sandstones were the same. *The difference between water propagation in samples with and without initial water saturation in Akin and Kovscek's experiments accords with the results of Du Prey and confirms the effect of initial water saturation on imbibition process even in water-wet samples.*

Baldwin and Spinler 12 monitored the saturation profiles during spontaneous imbibition using magnetic resonance imaging (MRI). The images monitored the
movement of imbibition front and saturation gradient across the front as a function of initial water saturation. They used reservoir rock core samples and decane as the hydrocarbon phase. At zero initial water saturation a sharp imbibition front was detected. As initial water saturation increased, a uniform saturation profile was developed through the rock, Fig. 1.37. In this thesis we will reproduce this behaviour by numerical simulation.

![Graph showing water saturation profile during 3D counter-current imbibition, S_wi=33% (after Baldwin and Spinler).](image)

Viksund et al.\(^7\) presented the results of 59 imbibition tests for various types of chalk and sandstone to investigate the effect of initial water saturation, S_wi. They used samples of Berea sandstone, Seaton low-permeability chalk, Rørdal chalk, Stevens chalk and Seaton high-porosity chalk. Fluids were two types of synthetic brine with almost similar density and viscosity but different ingredients as wetting phase and Soltrol 220 (\(\rho=797.5\) kg/m\(^3\), \(\mu=0.00424\) Pa.s) and refined oil (\(\rho=740\) kg/m\(^3\), \(\mu=0.00143\) Pa.s) as non-wetting phase. A wide range of 0-51 percent initial water saturation was established in different core samples. Based on experimental results, they concluded that increase in S_wi above zero percent in Berea sandstone was seen to decrease the imbibition rate whereas an overall opposite effect was obtained for four chalks. Imbibition rate for four kinds of the chalks tended to increase with increase in S_wi to a maximum at 34 percent and then decrease. Also final oil recovery for water-wet chalk decreased with
increase in $S_w$, whereas residual oil saturation was almost independent of $S_w$ for Berea sandstone.

Viksund et al.\textsuperscript{75} reported that they saw an induction time before the start of imbibition in chalk samples. Also they reported an increase in imbibition rate with increase in $S_w$. They stated that final oil recovery decreased with an increase in $S_w$. These properties are likely the properties of a mixed-wet system (The mixed-wet systems will be discussed in Sec. 1.4). Viksund et al.\textsuperscript{75} neither reported the wettability index of the samples nor compared the recovery of water-flooding with spontaneous imbibition to show that all the chalk samples were water-wet.

In water-wet rock it is expected that water occupies fine pores and grain contacts and covers the surface of larger pores and oil is present only in larger and intermediate-sized pores. When $S_w$ is higher, even intermediate size pores may be completely occupied by water and consequently oil can only exist in the largest pores over a thin water film that covers the rock surfaces. Therefore water can displace oil easily from larger pores and the water relative permeability is expected to be much higher. However capillary pressure expected to be lower at high water saturation. In this thesis will evaluate the effect of initial water saturation on counter-current imbibition through simulation using the Ma et al.\textsuperscript{52} scaling relation, Eq. (1.8).

### 1.2.5. Effect of other properties on imbibition

A wide range of factors that affect imbibition recovery have been tested and analysed in the literature. The effect of interfacial tension (IFT) on imbibition recovery was tested by Cuiec et al.\textsuperscript{24}, Babadagli and Al-bemani\textsuperscript{9}, Al-lawati and Saleh\textsuperscript{2}, Chimienti et al.\textsuperscript{21} and Najurieta et al.\textsuperscript{56}. The effect of temperature and its impact on wettability was discussed by Chimienti et al.\textsuperscript{21} and Najurieta et al.\textsuperscript{56}. Iffly et al.\textsuperscript{40} and Najurieta et al.\textsuperscript{56} analysed the influence of fluid compositions on imbibition recovery and Iffly et al.\textsuperscript{40} Hamon and Vidal\textsuperscript{38} and Viksund et al.\textsuperscript{75} discussed the effect of rock properties and heterogeneity on imbibition recovery. Hayashi and Rosales\textsuperscript{39} based on their experiments concluded that that imbibition could reasonably be visualized as a diffusion phenomenon.
1.2.6. Conclusions

Fractured carbonate reservoirs are important oil and gas resources. These reservoirs are composed of two continua: the fracture network and matrix. The fractures typically have a high permeability but very low volume compared to the matrix, whose permeability may be several orders of magnitude lower, but which contains the majority of the recoverable oil. Water-flooding is frequently implemented to increase recovery in fractured reservoirs.

Imbibition is the mechanism of displacement of non-wetting phase by wetting phase. Strong capillary forces lead to the imbibition of water as the wetting phase into the matrix and the discharged oil is displaced into the fractures. In water-wet fractured reservoirs, imbibition can lead to significant recoveries.

Imbibition can take place by co-current and/or counter-current flow\textsuperscript{2,18,38,40,57,59}. Co-current imbibition is faster and can be more efficient than counter-current imbibition\textsuperscript{18,21,59} but counter-current imbibition is the only possible displacement mechanism for cases where a region of the matrix is completely surrounded by water in the fractures\textsuperscript{56,59,69}. The imbibition rate is controlled by the permeability of the matrix, its porosity, the oil/water interfacial tension and the flow geometry\textsuperscript{18,21,22,24,29,38,40,52,61}, although the ultimate recovery is generally only governed by the residual oil saturation.

Scaling laws have been developed to predict the recovery from counter-current imbibition as a function of time for different samples. Mattax and Kyte\textsuperscript{54} hypothesized that the oil recovery for systems of different size, shape and fluid properties was a unique function of a dimensionless time. Ma et al.\textsuperscript{52} modified the Mattax and Kyte\textsuperscript{54} scaling law to include the effect of the non-wetting phase viscosity, Eq. (1.8). Their\textsuperscript{52} experimental results showed that the imbibition time is proportional to the geometric mean of the water and oil viscosities. Zhou et al.\textsuperscript{80} presented another scaling equation to include the effect of high mobility ratios, Eq. (1.11).
Recovery as a function of time for a variety of experiments on different water-wet samples falls on a single universal curve as a function of the dimensionless time, $t_D$, Eq. (1.8)$^{52}$, Fig. 1.11. In particular, imbibition experimental data presented by Mattax and Kyte$^{54}$ for Alundum samples and Weiler sandstones, Hamon and Vidal’s$^{38}$ results for synthetic materials and Zhang et al.’s$^{79}$ results for Berea sandstones with different boundary conditions all scaled onto the same curve that was reasonably well fitted by the empirical function, Eq. (1.10).

In this thesis we evaluate scaling equations using available experimental data with initial water saturation and for a wide range of water-oil viscosity ratios. We use the Ma et al.$^{52}$ scaling law, Eq. (1.8) to derive a transfer function for field scale dual porosity simulation of flow in water-wet fractured reservoir and see the effect of fracture injection rate on matrix imbibition patterns and recovery.

1.3. Wettability variation in reservoir rocks

In a fractured reservoir, after the start of oil production and decline of the oil pressure, water can enter the oil zone via a connected fracture network subject to sufficient aquifer pressure. Also water can be injected either under the initial fracture water-oil level or directly into the oil column in a flooding pattern. In the water-invaded zone, which is normally located down-structure, water displaces oil from the matrix blocks that have been exposed to oil since the end of oil migration and accumulation and which may therefore be oil-wet. Thus the wettability of the rocks that will be invaded by water has a significant role in the production behaviour and ultimate recovery.

Marzouk$^{53}$ reported wettability measurements in two major carbonate oil reservoirs. The reservoirs rocks cover several types of limestones and dolomites. The measurements were carried out by different contractors using mainly the Amott method under ambient conditions. Based on these data he stated that a plot of wettability versus depth shows a remarkable trend indicating an oil-wet character in the oil zone, mixed-wet in the transition zone and water-wet in the water zone. Plots of wettability versus $S_{wi}$ for different rock types indicate oil-wet character at low $S_{wi}$, mixed-wet at intermediate $S_{wi}$ and water-wet at high $S_{wi}$. The samples with
higher permeability were more oil-wet and vice versa. Similar rocks but from different levels in the oil column had different wettabilities. The reason for this is that for lower $S_{wi}$ more of the solid surface is in direct contact with oil. These surfaces might become oil-wet. As $S_{wi}$ decreases more of the pore surfaces are rendered oil-wet.

Basu and Sharma\textsuperscript{14} studied the effects of brine salinity, pH and oil composition on wettability alteration of glass and mica. They measured the wetting properties by measuring the capillary pressure required to rupture thin films of brine on the mineral substances using an atomic force microscope. They concluded that the presence of oil imposes a capillary pressure on the brine films. These thin films are related in a complicated way to the brine chemistry, oil composition and surface morphology. Regions of high positive (convex) curvature will become oil-wet as the brine films are ruptured on these surfaces. Concave regions of the pore surface will remain water-wet even at much higher capillary pressure. At higher capillary pressures (higher levels above (initial) oil-water level) it is anticipated that more pore surfaces will become oil-wet resulting eventually in continuous and connected paths of oil-wet pore surfaces that lead to mixed-wettability. Based on this theory, a change of wettability from weakly water-wet to mixed-wet and finally oil-wet is expected through the oil column. The range of this variation mainly depends on the height of oil column assuming no change in fluid composition or little pore-geometry variation.

Hamon\textsuperscript{37} studied the effect of structural position and permeability on capillary pressure, spontaneous imbibition, residual oil saturation and wettability. He used the results of 26 drainage and imbibition capillary pressure tests on sandstone preserved cores that were measured at reservoir conditions by using reservoir fluids. The cores were selected from a wide range of permeability of 1-1600 md and different heights above the initial water-oil level from 4 m to 175 m. Drainage and imbibition capillary pressure measurements performed with long stabilization periods such that the overall periods for drainage, imbibition and water injection were 40, 15 and 20 weeks respectively. The plot of spontaneous water imbibition recovery versus permeability for samples located upstructure is shown in Fig. 1.38. He stated that this plot clearly shows a strong trend: the higher the permeability the
smaller the degree of spontaneous imbibition. Fig. 1.39 shows spontaneous imbibition versus height of (the sample) above initial water-oil level (WOL). He stated that this plot shows a clear evidence of a strong trend between these two parameters: the closer to the WOL, the greater the degree of spontaneous imbibition. \textit{The curve fit to the data in this plot has little justification}. The plot of residual oil saturation ($S_{or}$) for samples located upstructure for case what he called forced imbibition (water injection) is shown in Fig. 1.40. The trend he concluded is the higher the permeability, the smaller $S_{or}$. Fig. 1.41 shows $S_{or}$ versus sample heights above initial water level. The closer to WOL, the greater $S_{or}$. The effect of height on $S_{or}$ is nearly twice the effect of permeability despite the large permeability range.

The equivalent characteristics based on wettability index to water were also tested and presented. Fig. 1.42 shows that the wettability index to water decreases as the sample height above the original WOL increases although the curve fit to the data in this plot has little justification. Fig. 1.43 shows the relation between wettability index to water of the samples located upstructure between 95 m and 120 m above original WOL and permeability. He stated that at the same structural position, the higher the permeability the less water-wet the sample. The results also shows the closer the wettability index to neutral, the larger the final recovery. This conclusion is consistent with previous results\textsuperscript{4,5}. \textit{The results shown in Figs. 1.38 to 1.43 are consistent with each other and also with the literature}\textsuperscript{4,5,33}. Reduction of permeability is equivalent to an increase in the initial water saturation and hence an increased tendency toward water-wetness and an increase in the amount of spontaneous imbibition. Moreover, increasing height above the original WOL will result in a lower initial water saturation, more oil-wet pores and less water-wet behaviour and hence a decrease in the amount of spontaneous imbibition.
Fig. 1.38. Imbibition recovery vs. permeability for upstructure samples.

Fig. 1.39. Imbibition recovery vs. structural position for low permeability samples. (after Hamon)

Fig. 1.40. Residual oil saturation vs. permeability for upstructure samples.

Fig. 1.41. Residual oil saturation vs. height above WOC for low permeability samples. (after Hamon)

Fig. 1.42. Wettability vs. structural position.

Fig. 1.43. Wettability index vs. permeability for upstructure samples. (after Hamon)
Jerauld and Rathmell\textsuperscript{43} presented a case study of wettability and relative permeability variation in the mixed-wet Prudhoe Bay reservoir. They used different data for this evaluation. Contact angle and adhesion data, micro-model and Cryo-scanning electron microscopy (Cryo-SEM), Amott wettability indices and finally relative permeability and capillary pressure behaviour were the data they used. Adhesion tests involved assessing wettability by placing a drop of oil on glass through brine and watching to see if the crude sticks, partially sticks or separates entirely from a glass surface.

Comparison of samples with different levels of asphaltenes indicated that more asphaltene-rich samples have more oil-wet behaviour. Low rate water-floods were performed at room conditions in two-dimensional etched-glass micromodels to examine the pore-level displacement mechanisms. Both micromodel and adhesion tests demonstrate that pH and asphaltene content influence wettability. Amott test results show intermediate to mixed-wet behaviour in the up- to midstructure regions tending toward water-wet behaviour near the water/oil contact in accordance with the trend observed by Hamon\textsuperscript{37} and others\textsuperscript{14,53}.

Buckley et al.\textsuperscript{20} performed experiments to demonstrate different distinct mechanisms of the adsorption of the polar component of crude oil on pore surfaces which lead to wettability changes. They concluded that adsorption of crude oil components alter the wetting of mineral surfaces. The main factors affecting the efficiency of the mechanisms were brine composition and solvent quality of the oil for its asphaltenes.

Amroun and Tiab\textsuperscript{3} reported a case study of wettability experiments on six samples of crude oil with a range 0-2.69 percent asphaltene to study the effect of asphaltene deposition on wettability alteration. Oil densities were between 30 and 50 °API. Porosity and permeability ranges of the samples were 16-20 percent and 650-2000 md respectively. They concluded that the samples are very close to neutral wettability and wettability alteration due to asphaltene deposition is irreversible. At higher concentration of asphaltenes in the crude oil the rocks have greater tendency to become neutrally-wet.
Kaminsky and Radke\textsuperscript{45} discussed the mechanisms of wettability alteration. They presented a transfer model for asphaltene diffusion from an oil/water interface through a water film followed by adsorption at solid/water interface. They wanted to calculate the total time for diffusion of low solubility asphaltene through a water layer. Their work was based on three assumptions: a) according to Salathiel's\textsuperscript{57} mixed-wet model, larger pores become oil-wet and smaller pores remain water-wet and the oil-wet and water-wet regions are connected; b) oil can either be in direct contact with rock or separated from the rock by aqueous film; and c) if a critical capillary pressure is exceeded, the aqueous films destabilize and rupture to an adsorbed molecular film of up to several monolayers so that crude oil can contact the rock directly. They suggested that contrary to popular belief, even for extremely low solubility, their calculations show adsorption equilibrium within a few hours. However, asphaltene adsorption on reservoir rock in the presence of a finite water film is not strong enough to initiate wettability alteration unless the water film ruptures.

\section*{1.3.1. Conclusions}

Wettability in the reservoir changes through the oil column\textsuperscript{14,37,45}. The most accepted trend is wettability variation from water-wet down-structure to mixed-wet up-structure. This is due to the variation in initial water saturation. As the water saturation decreases with height, more of the solid surface is in direct contact with the reservoir oil rendering more of the surface oil-wet. In addition, the capillary pressure increases with height and this allows more water films to rupture, again increasing the contact of oil with the solid. The residual oil saturation decreases with height and is a minimum for neutrally-wet or mixed-wet conditions. The amount of spontaneous imbibition decreases as the medium becomes more oil-wet.

It is accepted that asphaltenes are the principal agent that can change the wettability of a pore surface\textsuperscript{3,10,20,45} when rock surfaces are directly exposed to it. Brine composition and pH also impact wettability\textsuperscript{14,42,43}. 

\textit{Analysis, Scaling and Simulation of Counter-Current Imbibition}  
\textit{H. Sh. Behbahani}
1.4. Water displacement in non-water-wet rocks

The wettability of reservoir rock is a very important parameter affecting flow properties. It has been shown to affect relative permeability, capillary pressure, irreducible water saturation, residual oil saturation, spatial fluid distribution and water-flooding behaviour.

Different types of wettability can be categorized generally into two main groups as uniformly wetted and non-uniform-wetted or heterogeneous-wetted porous media. In uniformly wetted rocks, all pores of the rock regardless of their size and shape have the same wettability. In the other category, the rock pores have different wetness towards either oil or water and the behaviour depends on the fraction and distribution of the pores with different wettability.

1.4.1. Effect of wettability on oil recovery

Anderson reviewed the literature on the effect of wettability on relative permeability. He explained that in a uniformly wetted system, the wetting fluid will generally be located in the small and intermediate sized pores while the non-wetting fluid is located in the centre of the larger pores. In a strongly water-wet (i.e. uniform water-wet pores) rock initially at irreducible water saturation, water as the wetting phase will occupy the small pores and form a thin film over all of the rock surfaces. Oil as non-wetting phase will occupy the centres of the larger pores. When water enters the rock, it will tend to imbibe into any small or medium-sized pores. When water is displacing oil, oil can exist either in continuous channels with some dead-end branches or trapped in discontinuous globules as shown in Fig. 1.44. At some points, the neck connecting the oil in the pores will become unstable and break leaving a trapped oil globule. Oil can be trapped in two basic forms: (1) small globules in the centre of the larger pores and (2) larger patches of oil extending over many pores but completely surrounded by water.

For strongly oil-wet systems, the mechanism is the same by reversing the place of fluids, Fig. 1.44. In this case, oil can be trapped in the (1) smaller pores, (2) continuous films over the pore surfaces and (3) larger pockets of oil surrounded...
by water. Typical relative permeabilities for uniformly water-wet and oil-wet systems are illustrated in Fig. 1.45.

Fig. 1.44. Water displacing oil from (A) strongly water-wet rock, (B) Strongly oil-wet rock (after Anderson').

Fig. 1.45. Typical relative permeability (a) Strongly water-wet, (b) strongly oil-wet (after Anderson').

Anderson' in his literature review reported results showing the influence of wettability changes on both oil recovery rate and ultimate recovery. In Fig. 1.45 the effect of wettability on water-flooding performance (i.e. oil recovery rate) is shown in terms of change of contact angle in a sandstone outcrop. He concluded that the efficiency of water-flooding after one pore volume (PV) injection decreased as rock wettability varied from water-wet to oil-wet. However, the efficiency of water-flooding would be improved if the injection continued. The effect of wettability change on oil recovery rate in terms of changes in aging time is shown in Fig. 1.46. Here the same result can be concluded. The effect of wettability on the ultimate recovery of a water-flood system on an artificial core of chemically consolidated sand and the results of another test on outcrop sandstone in term of residual oil saturation versus wettability showed that the maximum ultimate recovery and minimum residual oil saturation occurred when the rock is neutral to
slightly oil-wet. When the samples are strongly water-wet, water isolates the oil droplets in the centre of the larger pores and hence the residual oil saturation is high. When the samples are strongly oil-wet, oil remains in wetting layers and small pores and flows very slowly.

Fig. 1.46. Effect of wettability on water-flood performance (after Anderson).

Fig. 1.47. Effect of aging time on water-flood performance (after Anderson).

Jadhunandan and Morrow\textsuperscript{42} studied the oil recovery of crude oil/brine/rock systems that cover a wide range of wettability states (indicated by Amott tests). They used Berea sandstone and carried 50 slow rate water-floods. They also observed that the water-flood recovery is optimum at close to neutral wettability which is in line with Anderson\textsuperscript{5}.
1.4.2. Mixed-wettability

Morrow and Mason\textsuperscript{55} stated that in early studies, the effects of wettability were often obtained for very strongly water-wet and very strongly oil-wet conditions under the assumption that the results will cover all possibilities between these two extremes. It is now recognized that there are an infinite number of wettability states between these two conditions that can behave quite differently.

Salathiel\textsuperscript{67} introduced the term mixed-wettability for a special type of fractional or non-uniform wettability. He suggested that when porous rocks can be flooded by water to an unusually low oil saturation, we may visualize a mixed-wettability condition that will provide paths for oil to flow even at very low saturations. In this condition the small pores and grain contacts would be preferentially water-wet and the surfaces of the larger pores would be strongly oil-wet. If oil-wet paths were continuous through the larger pores water could displace oil and very little or no oil can be held by capillary forces. In other words, the bypassed and immobile oil can be connected to the waterfront by thin filaments of oil probably on the continuous oil-wet surfaces. This situation allows a substantial portion of bypassed oil to drain experimentally. He described the mechanism of the generation of this type of wettability as follows: when oil initially invaded an originally water-filled water-wet reservoir, it displaces water from the larger pores while smaller pores remain water-filled because of strong capillary forces. After extended periods of exposure to this distribution, if some organic materials from oil deposit onto rock surface that are in direct contact with oil, the wettability of these surfaces can be changed to strongly oil-wet.

Salathiel\textsuperscript{67} compared the result of water-flooding in a strongly water-wet sandstone outcrop with the same rock but with its wettability artificially changed to be mixed-wet. The results are shown in Fig. 1.48.

For the strongly water-wet sample, little oil was produced after breakthrough and the residual oil saturation was about 35 percent. In the mixed-wettability test, more oil was recovered for the same injected volume and more importantly oil recovery continued as water was injected beyond breakthrough. The ultimate residual oil
saturation was about 10 percent or even less because oil recovery continues as more water is injected as can be seen in the insert of Fig. 1.48. The result of waterflooding of a preserved core from a field with mixed-wettability had the same results. This means the oil recovery in Figs. 1.46 and 1.47 could be more for non-water-wet cases if water injection continued.

![Graph of water-flood behaviour for mixed-wet and water-wet cores](image)

Fig. 1.48. Comparison of water-flood behaviour for mixed-wet and water-wet cores (Insert shows extension of mixed-wettability flooding data (after Salathiel)).

To generate the Salathiel\textsuperscript{67} type of mixed-wettability that leads to very low residual oil saturations, proper conditions are needed. The oil composition is critical because it must have some surface-active agents and/or organic materials that can be separated from the oil and deposited on directly exposed rock pore surfaces. The pore geometry and continuity is also very important. The amount of connate water during deposition of an oil-wet film affects the degree of contact of crude oil with the rock surfaces. Finally small pores must remain water-wet.

Further experimental results confirmed the nature of mixed-wettability defined by Salathiel\textsuperscript{67}. Sutanto et al.\textsuperscript{68} used Cryo-scanning electron microscopy (Cryo-SEM) as a direct method of determining in situ liquid distribution of oil and water in the pore space of reservoir rock. This method provides a means of visualizing oil and water in the individual pore segments of a porous rock. Two sandstone samples were studied. The result of this study confirmed Salathiel’s\textsuperscript{67} hypothesis on
interconnected water-wet surfaces and interconnected oil-wet surfaces but mentioned that the distribution of oil-wet and water-wet surfaces is not as simple as in Salathiel’s model.

Kamath et al.\textsuperscript{44} used three dimensional (3D) Computed Tomography (CT) images with conventional laboratory tools to provide a comprehensive picture of unsteady and steady water-flood recovery behaviour in four initially dried and unpreserved carbonate cores. They suggested that at least part of the oil production on increase of flow rate in the four carbonate samples is due to reduction in residual oil saturation. This result is in line with Salathiel’s view\textsuperscript{67}.

Graue et al.\textsuperscript{34} carried out experiments on initially strongly water-wet and moderately water-wet chalk blocks to predict oil recovery mechanisms in fractured chalk as a function of wettability. They monitored the fluid distribution with nuclear-tracer. The porosity of blocks were in the range 47.6 to 48.1 percent and their absolute permeabilities varied from 2.3 to 3.8 md. The Amott index ($I_w$) of samples aged in crude oil at 90 °C for 83 days was 0.54. The dimensions of the whole block were approximately $20 \times 12 \times 5$ cm obtained from an outcrop. The fractures were created as shown in Fig. 1.48. An open fracture with width of nearly 2 mm was created 13 cm from inlet. The other fractures were closed.

The moderately water-wet sample was water-flooded three times, first as a whole, then without the interconnected fracture network, and finally with the interconnected fracture network. They stated that the total movable oil (imbibition plus displacement) generally increased slightly with reduced water wettability that is inline with Salathiel’s view\textsuperscript{67}.

![Fig. 1.49. Experimental interconnected fractured network (after Graue et al.\textsuperscript{34}).](image)

Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani
Jerauld and Rathmell\textsuperscript{43} in their study of wettability variation in the mixed-wet Prudhoe Bay reservoir suggested that contact angles in the pore space appear to have a range of values from strongly oil-wet to strongly water-wet, with many that appear to be intermediate that is in line with Salathiel\textsuperscript{67}. Regions with intermediate contact angles had higher displacement efficiency with trapped oil resulting only from gross bypassing of a few pores filled with oil.

Fassi-Fihri et al.\textsuperscript{30} studied wettability and fluid distribution using Cryo-SEM with 0.1 micron resolution at the pore scale. They used sintered glass cores, one water-wet sandstone and two intermediate wettability reservoir samples of sandstone and carbonate rocks. The main result of their work was that wettability heterogeneity occurs at the pore scale and hence demonstrates the important effect of pore size and geometry on wettability.

### 1.4.3. Features of mixed-wet rocks

Morrow and Mason\textsuperscript{55} in their literature review suggested that experimental procedures for imbibition tests at mixed-wet conditions are inherently complicated and somewhat arbitrary. These tests can be several orders of magnitude slower and displacement efficiency ranges from barely measurable to significantly higher than obtained for very strong water-wet conditions. Mixed-wet imbibition curves exhibit considerable variation in shape. Sometimes very little or no imbibition is observed for a period described as the induction time. Mixed-wet samples can exhibit great sensitivity to initial water saturation.

One of the important characteristics of mixed-wet rock is its ability to imbibe both water and oil spontaneously. Buckley\textsuperscript{19} reported significant amount of spontaneous imbibition of both brine and oil into mixed-wet sandstone. Anderson\textsuperscript{5} also reported the results of experiments on preserved mixed-wettability cores indicating that these cores imbibed both water and oil.

Guo et al.\textsuperscript{35} studied imbibition water-flood performance in low permeability, naturally fractured Spraberry Trend Area reservoirs. They conducted imbibition and capillary pressure experiments using reservoir crude oil, synthetic reservoir brine and low-permeability reservoir cores under room and reservoir conditions. A
brine recovery curve obtained from their oil imbibition experiment demonstrated that a brine-saturated core spontaneously imbibed oil up to 9 percent pore volume. Capillary pressure data confirmed the interpretation of mixed-wetting behaviour.

Zhou et al.\textsuperscript{81} presented the results of 23 sets of spontaneous imbibition and 27 sets of water-flood experimental data for different wettability states and initial water saturations ($S_{wi} = 15, 20, 25$ percent). They aged samples of Berea sandstone with Prudhoe Bay crude oil (26.6 °API) at temperature of 88 °C from 1 to 240 hours to alter wettability of the samples from strongly water-wet toward mixed-wettability. Counter-current spontaneous imbibition was measured by change in weight of the aged samples that were hung in a degassed brine solution. To measure the wettability index, the samples were flooded at slow rates using a constant pressure of 5 psi. The water-flooding were stopped after 4 to 15 PV of brine injection when the water-oil ratio was greater than 99. The recovery at this point was used as an operational definition for the final water-flood recovery, $R_{wf}$.

The result of imbibition and water-flooding tests are illustrated in Figs. 1.50 to 1.52 for $S_{wi}$ of 15, 20 and 25 percent. In each figure, imbibition recovery versus time and water-flooding recovery versus PV injected are illustrated for different aging times as an indication of different wettibilities. Imbibition rate decreases and oil recovery by water-flooding increases with an increase in aging time as shown previously\textsuperscript{35,44,67,68}.

Fig. 1.50. (a) Oil recovery by imbibition vs. imbibition time and (b) oil recovery by water-flooding vs. pore volume of brine injected ($S_{wi} = 15\%$) (after Zhou et al.\textsuperscript{81}).
Fig. 1.51. (a) Oil recovery by imbibition vs. imbibition time and (b) oil recovery by water-flooding vs. pore volume of brine injected ($S_{w_i}=20\%$) (after Zhou et al.\textsuperscript{81}).

Fig. 1.52. (a) Oil recovery by imbibition vs. imbibition time and (b) oil recovery by water-flooding vs. pore volume of brine injected ($S_{w_i}=25\%$) (after Zhou et al.\textsuperscript{81}).

Zhou et al.\textsuperscript{81} to characterize the wettability state of the samples, used the ratio of separately determined imbibition and water-flooding recoveries as wettability index to water:

$$I_{w}^{'} = \frac{R_{im}}{R_{wf}}$$ \hspace{1cm} (1.15)

Fig. 1.53 shows how the modified wettability index ($I_{w}^{'}$) to water decreases with increase in aging time as a proof of wettability alteration of the samples used in these experiments.

Fig. 1.53. Wettability index for different aging times (after Zhou et al.\textsuperscript{81}).
Zhou et al.\textsuperscript{81} also used Ma et al.\textsuperscript{52} scaling law, Eq. (1.8) to scale the imbibition data. Imbibition data from Figs. 1.50 to 1.52 are presented as plots of normalized oil recovery in Fig. 1.54. A reference curve for imbibition in strongly water-wet Berea sandstone is also included. The authors stated that differences between this reference curve and their experiments are due to wettability effects.

![Fig. 1.54. Effect of aging time on imbibition oil recovery as a function of dimensionless time, Eq. (1.8) for different $S_{wi}$ (after Zhou et al.\textsuperscript{81}).](image)

Figs. 1.53 and 1.54 present two separate methods to prove different wettability state of the aged samples.

The result of oil recovery at breakthrough in Zhou et al.\textsuperscript{81} experiments is illustrated in Fig. 1.55. The authors stated that oil recovery at breakthrough as well as final oil recovery increases with aging time that causes a wettability change toward less water wettability. This agrees with Salathiel's observations\textsuperscript{67}.

Figs. 1.50 to 1.52 are genuine data of spontaneous imbibition in a mixed-wet rock. This means that there is a positive capillary pressure that enables the rock to imbibe water spontaneously even after an aging time of 240 hours. However, the imbibition time is several orders of magnitude slower.
Fig. 1.55. Oil recovery by water-flooding at breakthrough $R_b$ and final water-flood oil recovery $R_{o,f}$ vs. aging time for different initial water saturations (after Zhou et al.81).

In this thesis this data will be predicted using pore-scale modelling. We will analyse this behaviour to find out what is the key parameter causing this slow imbibition.

1.4.3.1. Induction time

Analysis of imbibition data in Figs. 1.50 to 1.52 shows that for a period of time no imbibition takes place. In other words there is a delay time before the start of imbibition in mixed-wet rocks. This period is called the induction time and is a characteristic of mixed-wet rocks.

Induction time in spontaneous imbibition is reported in the literature. Tang and Firoozabadi69 published the results of water injection and spontaneous imbibition experiments on an initially strongly water-wet Kansas chalk outcrop before and after the wettability was altered by chemical adsorption from strongly water-wet to intermediate wettability. The Kansas chalk outcrop consisted of nearly 99 percent calcite and 1 percent quartz and was free of chert and clay minerals. The samples were treated by steric acid as surfactant to alter the wettability state. The procedure for wettability alteration was repeated several times to establish a stable wettability. The wettability state of the samples was indicated by the Amott index to water ($I_w$) by hanging them in a brine solution and measuring the spontaneous counter-current imbibition and then water-flooding them at a high rate of 2 cm$^3$/min. The sample properties and configurations were illustrated and explained in section 1.2.3, (Fig. 1.31). All experiments were performed at room temperature.
Fig. 1.56 show the recovery data for spontaneous counter-current imbibition for chalk plug (configuration A that is single block) with two concentrations of wettability alteration agent. These tests were carried out to see the stability of altered wettability states. The recovery curves are close and so it can be concluded that the new wettability states were stable. It can be seen that recovery curves show an initial induction time. During this period no imbibition takes place, as shown previously in Figs. 1.50 to 1.52. Induction time increased as wettability changed toward less-water-wetness and the rate of imbibition also decreased. Final spontaneous counter-current oil recovery decreased nearly 27 percent from 66 percent for strongly water-wet to 48 percent for weakly water-wet. The induction time increased by a factor of 1.33 from 600 minutes for \( I_w=0.74 \) to 1400 minutes for \( I_w=0.66 \) and by a factor of 3.6 to 2200 minutes for \( I_w=0.05 \).

![Graph showing oil recovery vs. imbibition time](image)

Fig. 1.56. Spontaneous imbibition in chalk, configuration A, (single block) (CSA=500 ppm) (after Tang and Firoozabadi\(^69\)).

In this thesis, we apply and analyse Zhou et al.\(^81\) experimental data to explain the induction time during spontaneous imbibition in mixed-wet rocks.

1.4.3.2. Effect of initial water saturation

Salathiel\(^67\) found that the generation of mixed-wettability states was affected by the amount of water in the core during the aging process. Fig. 1.57 shows the effect of water saturation during aging on the residual oil saturation. Each curve shows the oil saturation after injection of the specified pore volume of water. At lower aging
water saturation, some of the small pores became oil-wet and traps the oil leading
to an increase in residual oil saturation. Also at larger aging water saturation,
portions of larger pores may still remain water-wet and reduce the continuous
oil-wet path and hence increase the residual oil saturation even after the injection of
many pore volumes of water.

The presence of water rings between oil-wet pores and/or discontinuous oil-wet
 pores made by pore geometry and/or very fine oil-wet pores prevent development
 of mixed-wettability and increase the residual oil saturation. These may be among
 the reasons that lead to higher residual oil saturations in strongly oil-wet or
 non-uniform wettability samples. Another reason for high apparent residual oil
 saturation may be the effect of insufficient pore volume injection or limited allowed
time for oil recovery.

Jerauld and Rathmell\(^1\) showed that there is a strong correlation between initial
water saturation and Amott wettability index with more water-wet behaviour at
higher initial water saturation Fig. 1.58. The trends in these data are essentially the
same as those observed in Berea sandstone\(^2\). It seems the dependence of
wettability on initial water saturation is a common feature of many mixed-wet
systems.
Chapter: 1

Fig. 1.58. Dependence of wettability index on initial water saturation (after Jerauld and Rathmell).³³

The effect of different initial water on oil recovery by imbibition and water-flooding for 240 hours aged samples in Zhou et al. experiments is shown in Fig. 1.59. Oil imbibition rate and final recovery increased with increase in $S_{wi}$ whereas oil recovery by water-flooding decreased with increase in $S_{wi}$ agreeing with previous studies.³³,⁶⁷

Fig. 1.59. Effect of initial water saturation on (a) Oil recovery by imbibition and (b) Oil recovery by water-flooding (after Zhou et al.).³¹

Tang and Firoozabadi⁶⁹ present the effect of initial water saturation on oil recovery by water injection for intermediate wettability, Fig. 1.60. The effect of initial water saturation on oil recovery increases as the wettability changes toward intermediate wettability. The same sequence of tests was conducted for configuration B that was a stack of six cylindrical chalk blocks.
The effect of initial water saturation on oil recovery for a weakly water-wet system by water injection is illustrated in Fig. 1.61. The results show that the oil production rate systematically increased with increase in initial water saturation.

![Graph showing oil recovery vs. water injection time for different initial water saturations.](image1)

Fig. 1.60. Effect of initial water saturation on oil recovery by water injection: intermediate-wet water-wet, configuration A, (single block) ($C_{SA}=1000$ ppm) (after Tang and Firoozabadi).

![Graph showing oil recovery vs. water injection time for different initial water saturations.](image2)

Fig. 1.61. Effect of initial water saturation on oil recovery by water injection: weakly water-wet, configuration B, (stack of six blocks) ($C_{SA}=500$ ppm) (after Tang and Firoozabadi).

Morrow and Mason in their review stated that the imbibition time for very strongly water-wet samples varies by much less than an order of magnitude over the range of initial water saturation from 10-30 percent as can be seen in Fig. 1.62, while the rate of spontaneous imbibition for mixed-wet media decreases by up to...
several orders of magnitude when the initial water saturation varies from 15 to 30 percent. Hence clearly, initial water saturation has a dominant influence on rock wetting and recovery behaviour in mixed-wet reservoirs. *In this thesis we will predict and interpret this behaviour using pore-scale modelling.*

![Graph showing dimensionless imbibition time as a function of initial water saturation. Notice that for mixed-wet media the imbibition rate varies by several orders of magnitude for relative small changes in initial water saturation.](image)

*Fig. 1.62. Dimensionless imbibition time as a function of initial water saturation. Notice that for mixed-wet media the imbibition rate varies by several orders of magnitude for relative small changes in initial water saturation. In this thesis we will explain and predict these results using pore-scale modelling and interpret the behaviour in terms of pore-scale displacement processes (after Morrow and Mason).*

### 1.4.4. Scaling of imbibition in mixed-wet rocks

Eq. (1.8) is for strongly water-wet rocks, where it is assumed that the oil/water contact angle $\theta$ is close to zero. It was discussed that mixed-wet rocks can spontaneously imbibe water. Therefore an equation for the prediction of oil recovery in mixed-wet systems needs to include the effect of relative wettability to oil and water. To include the relative wettability, Gupta and Civan\(^{36}\) and Cil et al.\(^{22}\) presented the following equation:

$$t_D = t \sqrt{\frac{K \sigma \cos(\theta)}{\phi \sqrt{\mu_w \mu_o} L_c}}$$  \hspace{1cm} (1.16)
By this equation, they tried to include the effect of the complex nature of wettability state of mixed-wet rocks by one parameter. This procedure is an empirical fit to data because one contact angle cannot explain various pores with different wettability states.

Zhou et al.\textsuperscript{81} also presented a term as apparent dynamic advancing contact angle ($\Theta_{AD}$) to include the relative wettability more precisely to match their experimental results. They assumed that wettability is proportional to cosine of this angle. They suggested that this angle could be defined by analogy with the cylindrical tube models. Comparison with recovery for strongly water-wet conditions is another proposed way to determine this angle. They used the following relations for this angle and corresponding dimensionless time:

\[
\Theta_{AD} = \cos^{-1}\left(\frac{t_{D,\text{frac}}(0.5)}{t_D(0.5)}\right) \tag{1.17}
\]

\[
t_D = t \sqrt{\frac{K}{\phi \frac{\sigma \cos(\Theta_{AD})}{\sqrt{\mu_w \mu_o}}} \frac{1}{L_c^2}} \tag{1.18}
\]

where $t_D(0.5)$ is defined as the dimensionless time, Eq. (1.8) for one half of the total recovery.

Xie and Morrow\textsuperscript{78} tested Eq. (1.8) in 32 weakly water-wet Berea sandstone samples with different boundary conditions, where their wettability was changed by aging in an asphaltic crude oil after establishment of initial water saturation ranging from 14 percent to 31 percent. They suggested that when capillary forces are sufficiently small, gravity segregation will make a significant contribution to oil recovery, therefore this force must be included in scaling laws for linear imbibition in weakly water-wet rocks. They presented the following equation for this type of imbibition:

\[
t_D = t \frac{K/\phi}{\sqrt{\mu_w \mu_o}} \left( P_{ci} f(\Theta) + \frac{\Delta \rho g L_c^2}{L_H} \right) \tag{1.19}
\]
where $P_{ci}$ is a representative imbibition capillary pressure proportional to $\sigma / \sqrt{k / \Phi}$, $f(\Theta)$ is a wettability factor and $L_h$ is vertical height of the sample.

*While this approach is appealing it lacks a sound theoretical basis. Since the cores are mixed-wet, there are water-wet and oil-wet regions of the pore space, and the assignment of a single effective contact angle is an empirical fit to the data which does not represent a typical contact angle in the porous medium. Furthermore, the thousand-fold decrease in imbibition rate is unlikely to be accounted for by contact angle effects alone. Last, the analysis ignores the apparent induction time and assumes that the mixed-wet recovery curves are simply re-scaled versions of the recovery for strongly water-wet conditions. This is only approximately true.*

Tang and Firoozabadi\textsuperscript{69} stated that the induction time for water imbibition cannot be simulated with current simulators and no attempt has yet been made to model spontaneous imbibition in mixed-wet media either by scaling or by pore-scale modelling.

*In this thesis we will work to present a scaling law for spontaneous imbibition in mixed-wet rocks.*

**1.4.5. Conclusions**

The most accepted non-uniform non-water-wet model of wettability was initially proposed by Salathiel\textsuperscript{67} that was confirmed by others\textsuperscript{35,43,44,68}. Based on this model, the fine pores and grain contacts remain water-wet and larger pores may become oil-wet due to direct contact with crude oil. Non-uniform wettability occurs at the pore scale\textsuperscript{4,43,67} and therefore pore size and geometry and reservoir rock mineral are relevant factors affecting wettability state\textsuperscript{43,67}.

Mixed-wet rocks have some special features. One important characteristics is that mixed-wet rocks have the ability to imbibe both water and oil spontaneously\textsuperscript{5,19,35,81}. Also there is an induction time (delay time) at the start of imbibition. Oil recovery from mixed-wet rocks can be continued for a long time.
after water breakthrough as a result of a thin interconnected oil films. Initial water saturation has a definite effect on oil recovery for mixed-wet rocks. Oil recovery by imbibition in mixed-wet rocks can increase significantly with increase in initial water saturation. Also an increase in pressure gradient in mixed-wet rocks can increase the oil recovery and decrease the induction time.

This review shows that recovery characteristics of mixed-wet rocks are complex. However due to wettability variations in fractured reservoirs it is necessary to understand the physics of imbibition in mixed-wet rocks. In this thesis we will analyse the behaviour of imbibition in mixed-wet rocks and present a scaling law to predict the behaviour.

1.5. Simulation of Water Displacement

1.5.1. Dual porosity modelling

A general approach to simulate the behaviour of fractured reservoirs is the dual porosity concept. In this type of model, the fracture network is the main path of the flow and the matrix blocks behave as source or sink to this flow. In this approach, the fracture network and matrix block grid systems are superimposed on each other. The fluid transfer between these two systems is defined by a transfer function. Therefore this term has an important effect on the simulation results.

The equation for immiscible oil and water transfer between matrix (ma) and fracture (f) in dual porosity simulators for each phase is:

\[ T^*_{ma} (\Phi_f - \Phi_{ma}) = \phi_{ma} \frac{\partial S_{ma}}{\partial t} \]  \hspace{1cm} (1.20)

\[ \Phi = P - \gamma D \]  \hspace{1cm} (1.21)

where \( T^* \) is matrix transmissibility coefficient, \( \Phi \) is potential, \( \phi \) is porosity, \( S \) is saturation, \( P \) is pressure, \( D \) is depth from datum (positive downward) and \( \gamma \) is fluid gradient.
In a finite difference simulation model, an upstream weighting factor (ω) is used in the matrix transmissibility equation so that mobility is evaluated in the direction that flow is coming from. Gilman and Kazemi\textsuperscript{32} defined the matrix-fracture transmissibility for each phase as:

\[ T_{ma}^{*} = C \sigma K_{ma} \Delta x \Delta y \Delta z [\omega (\frac{k_r}{\mu B})_{ma} + (1 - \omega)(\frac{k_r}{\mu B})_{f}] \] (1.22)

Where \(\sigma\) is shape factor, \(A\) is grid block dimensions in \(x\), \(y\) and \(z\) directions, \(K_{ma}\) is matrix absolute permeability, \(k_r\) is relative permeability, \(\mu\) is viscosity, \(B\) is formation volume factor and \(C\) is a constant equal to 1 in consistent units.

For \(K\) in md, \(\mu\) in cp, length in feet and pressure in psi, the constant coefficient \(C\) in the equation will be \(1.127 \times 10^{-3}\). In Eq. (1.22) ω is 1.0 when flow is from matrix to fracture and is 0.0 when flow is from fracture to matrix. \(\Delta x\), \(\Delta y\) and \(\Delta z\) are replaced later on with bulk volume \(V_B\).\textsuperscript{47} Based on Eqs. (1.20) to (1.22), the equations for imbibed water from fracture into matrix (ω = 0.0) and produced oil from matrix into fracture (ω = 1.0) in counter-current water imbibition, where gravity is neglected can be written as:

\[ \tau_w = C \sigma K_{ma} \Delta x \Delta y \Delta z (\frac{k_{rm}}{\mu_w B_w}) f (P_{wf} - P_{wma}) \] (1.23)

\[ \tau_o = C \sigma K_{ma} \Delta x \Delta y \Delta z (\frac{k_{mo}}{\mu_o B_o}) ma (P_{of} - P_{oma}) \] (1.24)

where the subscripts \(o\) and \(w\) stand for the oil and water phases and \(ma\) and \(f\) stand for matrix and fracture respectively.

In dual porosity equations some parameters such as fracture capillary pressure and relative permeability and shape factor need to be clarified. The fracture relative permeability for each phase is usually assumed to be equal to its saturation. Fracture capillary pressure is also difficult to measure and usually assumed to be zero.
The following assumptions are used to solve the two phase (oil/water) flow equations in dual porosity simulators:

\[ S_{of} = 1 - S_{wf} \quad (1.25) \]
\[ S_{oma} = 1 - S_{wma} \quad (1.26) \]
\[ P_{of} = P_{wf} + P_{cf} \quad (1.27) \]
\[ P_{oma} = P_{wma} + P_{cma} \quad (1.28) \]

The term \( P_c \) in Eqs. (1.27) and (1.28) refers to water-oil capillary pressure.

One important issue regarding potentials is the relation between fracture and matrix pressures for each phase. In the simulator, to solve the flow equations, it is assumed that initially the system is at capillary/gravity equilibrium. Then four flow equations (i.e., two equations for fracture and matrix flow solving for two phases) will be solved for each node to give the four unknowns that are fracture and matrix potentials and saturations.

A relation between fracture and matrix pressures for the counter-current water imbibition case with no gravity effect can be obtained. In this case the volumetric rate of oil recovery from matrix block is equal to the volumetric rate of water imbibition, that is:

\[ B_o \tau_w = -B_o \tau_o \quad (1.29) \]

Replacing \( \tau_w \) and \( \tau_o \) from Eqs. (1.22) and (1.23) will result in:

\[ \frac{k_{rw}}{\mu_w} (P_{wf} - P_{wma}) = -\frac{k_{rm}}{\mu_o} (P_{of} - P_{oma}) \quad (1.30) \]

Solving Eq. (1.29) for \( (P_{oma} - P_{of}) \) using Eqs. (1.26) and (1.27), a relation between fracture and matrix oil pressure can be derived as follows where \( \lambda \) is the mobility:

\[ P_{oma} - P_{of} = \frac{\lambda_{wf}}{\lambda_{wf} + \lambda_{oma}} (P_{cma} - P_{cf}) \quad (1.31) \]
Kazemi obtained the same equation for this case. We can re-write this equation in term of water and oil transmissibilities using Eqs. (1.23) and (1.24) and obtain:

\[ P_{oma} - P_{of} = \frac{T_{wf}^*}{T_{wf}^* + T_{oma}^*} (P_{oma} - P_{of}) \]  

(1.32)

1.5.1.1. Shape factor

Shape factor is a parameter to include the effect of shape and boundary condition. The mathematical expressions for shape factor were studied earlier in section 1.2.1.1 and presented by Eqs. (1.3) to (1.6). Analysis of Eqs. (1.22) to (1.24) show the major importance of shape factor in recovery calculations. However there is not a general agreement regarding definition of this parameter.

Beckner et al. stated that gross matches of experimental results of water imbibition with dual porosity models required shape factors that were un-representative of the matrix block size and a constant shape factor could not match the experimental data at different rates. Saidi strongly criticized this feature of dual porosity models. He suggested that this factor requires knowledge of block dimension, which is poorly known. Moreover, this factor varies from one mechanism to another within the same grid. When a block is under expansion drive, the shape factor is dominated by smallest dimension of the blocks. During solution gas-drive the vertical direction would become important, whereas during the gravity drainage period, it is dominated by block height. If at the same time, diffusion or imbibition is taking place, the smallest dimension also becomes the most significant. Therefore the shape factor should have different values for different mechanisms.

1.5.2. Experimentally-based transfer functions

Empirical functions are simple definitions for the oil recovery with characteristics of curve fitting functions. Arnofsky et al. first proposed that oil recovery by spontaneous imbibition as a function of time could be modelled by a simple exponential function, Eq. (1.9).
Kazemi et al.\textsuperscript{47} used Eq. (1.9) with substituting \( t \) by \( t_D \) defined by Mattax and Kyte\textsuperscript{54}, Eq. (1.1) and their definition for shape factor, Eqs. (1.3) and (1.4) and presented an empirical equation that matched Mattax and Kyte\textsuperscript{54} experimental data, Fig. 1.63. The value of rate constant \( \lambda \) in their relation is 0.0111\textsuperscript{47}.

![Fig. 1.63. Correlation of Mattax and Kyte\textsuperscript{54} experimental data (after Kazemi et al.\textsuperscript{47}).](image)

Ma et al.\textsuperscript{50} also used Eq. (1.9) with substitution of their own definition of \( t_D \), Eq. (1.8) for \( t \) to match the counter-current imbibition recovery data of Mattax and Kyte\textsuperscript{54}, Hamon and Vida\textsuperscript{38} and Zhang et al.\textsuperscript{79}, Eq. (1.10) (Fig. 1.11). The value of rate constant \( \lambda \) in their relation is 0.02\textsuperscript{52}.

De Swan\textsuperscript{26} presented an equation for the transfer function that matched experimentally determined imbibition rates. He suggested that while water advances in fractures, water-wet matrix blocks imbibe water and deliver oil into fractures. Therefore as time increases, the downstream blocks are subject to variable water and oil saturations depending on the imbibition of upstream blocks. When a matrix block is suddenly immersed totally in water (i.e. a unit step water saturation on the entire block surface), it will imbibe water and release oil based on an exponential function like Amofsky\textsuperscript{6}. He concluded that once this behaviour for unit step change is known, the behaviour under varying water saturation (neglecting gravity) is given by a convolution integral. Based on this justification,
he presented the following equation for water imbibition per unit fracture length ($W^*$):

$$ W^* = \frac{N \text{mobu}}{\tau^*_i} \int_0^{\tau^*_i} e^{-(1-\theta^*)/\tau^*_i} \left( \frac{\partial S_{mf} / \partial \theta^*}{\partial \theta^*} \right) d\theta^* $$

(1.33)

Where $N$ is total oil recoverable by imbibition per unit fracture length, $\tau^*_i$ is the time required to produce 63 percent of total recoverable oil by imbibition and $\theta^*$ is integration parameter with dimensions of time.

To solve the flow equation de Swan assumed that fractional flow of every phase is identical with the mobile saturation of that phase (i.e. $f_i = S_i$). This assumption is correct if the oil in the fracture is dispersed as droplets and entrained in the moving water in the fracture.

1.5.3. Limitation of dual porosity modelling

The fluid exchange between matrix and fracture media is defined by transfer functions in dual porosity modelling. Therefore this is the key parameter that affects the simulation results. This term is a function of matrix saturation, Eq. (1.21). The definition of the matrix saturation versus time is the most challenging part of this approach.

1.5.4. Derivation of an empirical transfer function

Kazemi et al. derived an empirical transfer function for counter-current imbibition using the Arnofsky et al. exponential relation, Eq. (1.9). If $R$ is matrix cumulative oil recovery at time $t$ and $R_\infty$ is matrix final oil recovery, we can write:

$$ R_m = (S_{wma} - S_{wcma}) \phi_{ma} $$

(1.34)

$$ R_\infty = (1 - S_{orma} - S_{wcma}) \phi_{ma} $$

(1.35)
where $S_{wma}$ is matrix water saturation at time $t$, $S_{wcma}$ is matrix connate water saturation, $S_{orma}$ is matrix residual oil saturation and $\phi_{ma}$ is matrix porosity. By combining Eqs. (1.9), (1.34) and (1.35) and assuming that oil recovery is proportional to fracture water saturation, $S_{wf}$ they got:

$$S_{wma} - S_{wcma} = S_{wf} (1 - S_{orma} - S_{wcma})(1 - e^{-\lambda t})$$  \hspace{1cm} (1.36)

Solving Eq. (1.36) for $e^{-\lambda t}$ gave:

$$e^{-\lambda t} = 1 - \frac{S_{wma} - S_{wcma}}{S_{wf} (1 - S_{orma} - S_{wcma})}$$  \hspace{1cm} (1.37)

They took the derivative of Eq. (1.36) and substituted it in Eq. (1.37) and got:

$$\frac{\partial S_{wma}}{\partial t} = \lambda [S_{wf} (1 - S_{orma} - S_{wcma}) - (S_{wma} - S_{wcma})]$$  \hspace{1cm} (1.38)

Where $\partial S_{wf} / \partial t (1 - S_{orma} - S_{wcma})(1 - e^{-\lambda t})$ assumed to be negligible because at early times $1 - e^{-\lambda t} = 0$ and at late times $\partial S_{wf} / \partial t = 0$. By this assumption, the Kazemi et al.\textsuperscript{47} equation does not cover the period that fracture water saturation varies.

Using definition of dual porosity transfer function, Eq. (1.21), Kazemi et al.\textsuperscript{47} empirical transfer function is:

$$T = \phi_{ma} \frac{\partial S_{wma}}{\partial t} = \lambda \phi_{ma} [S_{wf} (1 - S_{orma} - S_{wcma}) - (S_{wma} - S_{wcma})]$$  \hspace{1cm} (1.38)

The model assumes steady state flow to calculate $S_{wma}$.

In this thesis we use Ma et al.'s empirical fit\textsuperscript{52}, Eq. (1.10) to derive a transfer function for field scale dual porosity simulation of flow in a water-wet fractured reservoir.
1.6. Statement of the problem

Counter-current imbibition is a key recovery mechanism in fractured reservoirs. Simulation of this phenomenon in water-wet and mixed-wet rocks is an important task.

There is at least one semi-empirical equation, Eq. (1.8), which claims to match nearly all spontaneous counter-current imbibition experimental data in water-wet rocks with different boundary conditions. Is this claim correct? Fluid transfer between fracture and matrix is defined by transfer functions in dual porosity models. If the equation is correct then the validity of current transfer functions against this relation must be checked.

Can counter-current imbibition be explained using a conventional Darcy formulation for the flow equation? Can the empirical equation, Eq. (1.10), be used to simplify complex multi-dimensional imbibition? What is the effect of viscous forces on the result of simulation based on this equation?

The scaling of the spontaneous imbibition in non-water-wet rocks is a current problem that needs to be solved. How can the induction time at the start of spontaneous imbibition in mixed-wet rocks be explained? Can an appropriate set of relative permeabilities and capillary pressure produce similar behaviour?

Is there any scaling law for spontaneous imbibition in mixed-wet rocks that can correlate imbibition recovery for different wettability states and for various mobility ratios?
Chapter 2: Simulation of Counter-Current Imbibition in Water-Wet Fractured Reservoirs

Summary

In this chapter, counter-current imbibition, where water spontaneously enters a water-wet rock while oil escapes by flowing in the opposite direction is studied. In the first part of this chapter it is tested that whether or not counter-current imbibition can be explained using a conventional Darcy formulation for the flow equations. Fine grid, one- and two-dimensional simulations of counter-current imbibition are performed using two sets of relative permeabilities and capillary pressures and the results are compare with experimental measurements in the literature.

Then two-dimensional (2D) simulations of water flow through a single high permeability fracture in contact with a lower permeability matrix are performed. And the results are compared with experimental measurements of fracture flow and matrix imbibition in the literature and with one-dimensional (1D) simulations that account for imbibition from fracture to matrix using an empirical transfer function.

2.1. Introduction

It was shown (Fig. 1.11, sec. 1.2.1.2, ch. 1) that recovery as a function of time for a variety of experiments on different water-wet samples fall on a single universal curve as a function of the Ma et al.\textsuperscript{52} dimensionless time, $t_D$, Eq. (1.8)\textsuperscript{52}. This universal curve can be used to derive a transfer function.

Fig. 2.1 shows experimental imbibition data in the literature. While the data considered by Ma et al.\textsuperscript{52} does approximately lie on a single curve given by Eq. (1.8)\textsuperscript{52}, including the results of other experiments on water-wet samples from Bourbiuax and Kalaydjian\textsuperscript{18}, Cil et al.\textsuperscript{22} and Zhou et al.\textsuperscript{81} shows more scatter – in
particular for some of the experiments the imbibition rate is much slower than predicted by Eq. (1.10). The experiments analyzed by Ma et al.\textsuperscript{52} were performed on either artificial porous media (that is, not rock samples) or with an initial water saturation of zero. The other data that we have presented\textsuperscript{18,22,81} are all performed on sandstone cores with an initial water saturation present, which is more likely to be representative of reservoir displacements. It should be noted that only the data for an aging time of zero from Zhou et al.'s\textsuperscript{81} experiments were used to compare with other water-wet imbibition experimental results in Fig. 2.1.

This discrepancy from previous data correlated by Ma et al.\textsuperscript{52} was also seen by others. Ruth et al.\textsuperscript{64} stated that dimensionless time, $t_D$, Eq. (1.8) for imbibition into Berea sandstone is always longer than that for the correlation developed for $S_{wi}=0$. Tong et al.\textsuperscript{72} reported that dimensionless times for imbibition into the Berea sample they used were longer than previously observed for a wide range of porous media. Viksund et al.\textsuperscript{75} experimental results also showed that increase in $S_{wi}$ will decrease imbibition rate in Berea sandstone samples.

![Normalized oil recovery as a function of dimensionless time, Eq. (1.8), for counter-current imbibition on different core samples](image)

Fig. 2.1. Normalized oil recovery as a function of dimensionless time, Eq. (1.8), for counter-current imbibition on different core samples: Hamon & Vidal\textsuperscript{18}, Mattax & Kyte\textsuperscript{54}, Zhang et al.\textsuperscript{79}, Bourbiaux and Kalaydjian\textsuperscript{18}, Cil et al.\textsuperscript{22} and Zhou et al.\textsuperscript{81}. The solid line is Ma et al.'s\textsuperscript{52} empirical fit to the data, Eq. (1.10).
It has been suggested\textsuperscript{12} that a conventional formulation of the conservation equations is not sufficient to explain the results of counter-current imbibition experiments and that a description of multiphase flow with rate dependent coefficients is necessary to reproduce the results seen experimentally.

In the first part of this chapter we test whether or not counter-current imbibition can be explained using a conventional Darcy formulation for the flow equations, by using a standard reservoir simulator to predict recovery with input relative permeabilities and capillary pressures. The relative permeabilities and capillary pressures will come from the analysis of a counter-current imbibition experiment\textsuperscript{18} and from pore-scale modelling\textsuperscript{41}. We will test the validity of the scaling functions in Eqs. (1.8) and (1.11) by performing simulations for different oil/water viscosity ratios.

In the second part of the chapter, we study situations where there is flow in a fracture combined with imbibition into the matrix. It was explained (Sec. 1.2.2, Ch. 1) that Rangel-German and Kovscek\textsuperscript{61} experiments with different flow rates and fracture apertures illustrated two different fracture flow regimes “filling-fracture” and “instantly-filled”. In the instantly-filled regime, corresponding to high fracture flow rates, the flow into the matrix is strictly counter-current as the fracture is rapidly filled with water. At lower fracture flow rates water advances in the flow direction at comparable rates in the matrix and fracture. The average water saturation in the matrix scales with time in the filling-fracture regime whereas in the instantly-filled regime, it scales with the square root of time. We simulate this two-dimensional (2D) process using a model with a single fracture connected on either side to a water-wet matrix.

We will also reproduce the results using a one-dimensional (1D) simulation with a transfer function to account for the transfer of fluid from fracture to matrix. We use a transfer function based on empirical exponential fit to data by Ma et al.\textsuperscript{52}, Eq. (1.10) developed by DiDonato et al.\textsuperscript{28} in the context of streamline-based dual porosity simulation. In this section we investigate that a dual porosity approach can be used to represent fracture/matrix flow and transfer in a simple system.
2.2. Simulation of 1D-counter-current imbibition

Counter-current imbibition in one dimension (1D) is modeled using Eclipse®-100, which is an industry-standard reservoir simulator. In the 1D model, illustrated in Fig. 2.2, a region initially full of water with fracture properties (Tables 2.1 and 2.3) was connected to a thin matrix slab (Tables 2.2 and 2.3). A total of 42 grid blocks was used in the simulation, with smaller blocks at the inlet to capture accurately the initial advance of water into the matrix. Sensitivity studies using 200 grid blocks demonstrated that we used sufficient grid blocks to obtain converged results. All other faces not in contact with the fracture were closed (no flow boundaries). The relative permabilities of the fractures were assumed to be linear functions of saturation with no irreducible or residual saturation and the capillary pressure in the fracture was zero. The matrix relative permeabilities and capillary pressures are discussed later.

Conservation of water volume assuming incompressible flow and Darcy’s law in one dimension with no total velocity can be expressed as follows (Appendix-A):

\[
\frac{d}{dt} \int \frac{K}{\phi} \frac{\partial S_w}{\partial x} + \frac{\partial}{\partial x} \left( \frac{\lambda_a \lambda_d}{\lambda_t} K \left( \frac{\partial P_c}{\partial S_w} \frac{\partial S_w}{\partial x} + g_x (\rho_w - \rho_o) \right) \right) = 0 \tag{2.1}
\]

where \( P_c \) is the capillary pressure, the mobility \( \lambda = k_r / \mu \) where \( k_r \) is the relative permeability and \( \lambda_t = \lambda_w + \lambda_o \). \( \rho \) is the density and \( g_x \) is the component of gravity in the flow direction. The reservoir simulator solves Eq. (2.1) on the grid shown in Fig. 2.2 using an implicit finite difference formulation with upstream weighting of the mobility terms.

We assume that this conventional treatment of the flow equations with saturation-dependent capillary pressure, \( P_c \), and relative permeabilities, \( k_r \), is sufficient to predict the results of the experiments. As mentioned above, recently it has been suggested that a fundamentally different formulation of the conservation equations with rate-dependent coefficients is necessary to explain the results of imbibition experiments.
Table 2.1. Fracture properties used in 1D and 2D counter-current simulations.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial water saturation</td>
<td>1.0 fraction</td>
</tr>
<tr>
<td>Porosity</td>
<td>1.0 fraction</td>
</tr>
<tr>
<td>Capillary pressure</td>
<td>0.0 Pa</td>
</tr>
<tr>
<td>Permeability</td>
<td>50x10^{-12} m^2</td>
</tr>
</tbody>
</table>

Table 2.2. Matrix rock and fluid properties used in 1D and 2D counter-current simulations.

<table>
<thead>
<tr>
<th>Property</th>
<th>Base models</th>
<th>Network derived data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Source of Data</td>
<td>SPE 1828*</td>
<td>Network modelling*</td>
</tr>
<tr>
<td>Porosity</td>
<td>0.233</td>
<td>0.2</td>
</tr>
<tr>
<td>Permeability</td>
<td>124x10^{-15}m^2</td>
<td>3.148x10^{-12}</td>
</tr>
<tr>
<td>Oil density</td>
<td>760 Kg.m^{-3}</td>
<td>835</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>1.5x10^{-3} Pa.s</td>
<td>39.25x10^{-3} *</td>
</tr>
<tr>
<td>Water density</td>
<td>1090 Kg.m^{-3}</td>
<td>1010</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>1.2x10^{-3} Pa.s</td>
<td>0.967x10^{-3} *</td>
</tr>
<tr>
<td>Interfacial tension</td>
<td>0.0035 N.m^{-1}</td>
<td>0.0030</td>
</tr>
<tr>
<td>Initial water saturation</td>
<td>0.40 fraction</td>
<td>0.25</td>
</tr>
<tr>
<td>Residual oil saturation</td>
<td>0.422 fraction</td>
<td>0.75</td>
</tr>
</tbody>
</table>

* From Zhou et al.

Fig. 2.2. Grid system for one-dimensional simulation of counter-current imbibition. A total of 42 grid blocks were used.
2.2.1. Base models

For the base case, the matrix and fluid properties from counter-current imbibition experiments by Bourbiaux and Kalaydjian\textsuperscript{18} were used (Table 2.2). They reduced the measured co-current relative permeabilities by approximately 30 percent to match the counter-current experiment results. Counter-current relative permeabilities and capillary pressure from Bourbiaux and Kalaydjian\textsuperscript{18}, Fig. 2.3 were used in all base models.

Table 2.3. Fracture and matrix dimensions in 1D and 2D counter-current simulations

<table>
<thead>
<tr>
<th>Unit</th>
<th>1D modelling</th>
<th>2D modelling</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fracture</td>
<td>Fracture</td>
</tr>
<tr>
<td></td>
<td>Matrix</td>
<td>Matrix</td>
</tr>
<tr>
<td>X</td>
<td>cm</td>
<td>6.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6.1</td>
</tr>
<tr>
<td>Y</td>
<td>cm</td>
<td>1.2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>28</td>
</tr>
<tr>
<td>Z</td>
<td>cm</td>
<td>2.1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2.1</td>
</tr>
<tr>
<td>$L_c$</td>
<td>cm</td>
<td>28</td>
</tr>
</tbody>
</table>

Fig. 2.3. Matrix water-flood relative permeabilities and capillary pressure used in the base models from Bourbiaux and Kalaydjian\textsuperscript{18}.
2.2.1.1 Saturation and pressure profiles

In counter-current imbibition, oil and water move in opposite directions due to capillary forces. Figs. 2.4 and 2.6 show the oil and water saturation profiles for different time steps during counter-current imbibition for the base model. As the water imbines into the rock and displaces the oil, the oil saturation decreases through the sample. The oil saturation reduces from an initial value of 0.6 toward the residual value of 0.422.

The maximum oil saturation scales linearly with square root of time before the front reaches to the end of the rock. This is consistent with the relation between imbibition time and characteristic length in the Ma et al.\[12\] scaling relation, Eq. (1.8). For example, the maximum oil saturation after 0.5, 5 and 10 hours moves approximately to 5.25, 16.5, 23.5 cm from the sample inlet respectively. It means when the time increases by 10 and 20 times, the location of the saturation front moves relative to the square root of 10 and 20 to 16.5 and 23.5 cm from 5.25 cm.

Fig. 2.4. Oil saturation profile at different times. The location of the front scales linearly with the square root of time.
Fig. 2.5. Water saturation profile at different times. The location of the front scales linearly with the square root of time.

Figs 2.6 to 2.8 show the oil and water pressure profiles through the sample after 0.5, 5 and 10 hours. The gradient of the pressure profile is controlled by the total mobility. The capillary pressure is constant beyond the front and there is no flow. As a consequence the phase pressures are constant.

Fig. 2.6. Oil and water pressure profiles through the sample after 0.5 hours.
The capillary pressure is a maximum at the leading saturation front – this capillary pressure is the driving force for recovery. Notice at the inlet the capillary pressure is not zero – the finite capillary pressure here provides a driving force to push oil out of the system. These results are consistent with recent measurements and simulations by Li et al\textsuperscript{56} and also Baldwin and Spinler\textsuperscript{12}, Fig. (1.37).
2.2.1.2 Prediction of experimental recovery curves

Fig. 2.9 shows the measured and predicted oil recovery from Bourbiaux and Kalaydjian’s experiments. In the experiments, the core was held vertically, and so gravity effects are included in the simulation. Our simulation results are identical to experiments and to simulations performed by Bourbiaux and Kalaydjian using the same relative permeabilities.

Fig. 2.9 shows that a conventional simulator based on Darcy’s law can match literature counter-current imbibition experimental data in water-wet samples. However, the relative permeabilities used for the simulations were constructed by the original authors from co-current data to match the counter-current experimental results. This means the recovery curve was constructed by fitting two parameters and is unlikely to be unique because several different combinations of the parameters may give the same recovery curve. Therefore this match is not in any sense a genuine prediction.

![Fig. 2.9. Comparison of experimental and simulated (circles) recoveries for counter-current imbibition. The experimental data is from Bourbiaux and Kalaydjian. Also shown are the simulated results from Bourbiaux and Kalaydjian that agree very well with our predictions.](image-url)
Fig. 2.10 shows comparisons of the simulation results with the experimental data in Fig. 2.1. The Ma et al. expression, Eq. (1.10), under predicts the simulation results at early time (until dimensionless time \( \sim 7 \)) and over predicts the simulations thereafter. As it was mentioned earlier, simulations are the results of a grid based explicit modelling of fracture matrix transfer due to capillary forces.

In most of these experiments the cores were held vertically, and so for comparison we show a simulation result where gravitational effects have been neglected. This makes little difference to the results, except at late time and slightly improves the match to some of the other data.
2.2.2. *Network model derived relative permeabilities and capillary pressure*

In this section relative permeabilities and capillary pressure derived from pore-scale network modelling, Fig. 2.11, are used. The pore-scale model uses a network derived from a sample of Berea sandstone and can accurately predict co-current water-flood relative permeabilities for Berea\textsuperscript{17,41}. The model computes relative permeabilities and capillary pressures for drainage and imbibition cycles. The network model itself will be explained more later.

The experiments by Zhou et al.\textsuperscript{81} were performed on Berea sandstone. Hence, of all the results shown in Fig. 2.1, we would expect the network model properties to best represent this experiment. For a more careful comparison the oil and water viscosities from Zhou et al.\textsuperscript{81} were used in the simulations.

---

![Graph showing relative permeability and capillary pressure vs. water saturation](image)

**Fig. 2.11.** Matrix water-flood relative permeabilities and capillary pressure derived from network modelling of Berea sandstone from Jackson et al.\textsuperscript{41}
Fig. 2.12 shows the result of 1D counter-current imbibition simulations using network model derived data. The simulations accurately predict Zhou et al.’s experimental results\textsuperscript{81} in Berea Sandtone. This is a genuine prediction of the experimental results, in that the relative permeabilities and capillary pressure used were independently computed and no parameters were tuned to match the results.

It is interesting to note that the imbibition rate we predicted is approximately ten times slower than measured on artificial porous media or systems with no initial water saturation present. These results show the effect of rock type and initial water saturation on imbibition recovery.

Fig. 2.12. 1D counter-current imbibition simulations using network model derived data shown in Fig. 2.6 compared to experimental results in the literature and the experiments of Zhou et al.\textsuperscript{81} on Berea sandstone.
2.3. Simulation of 2D-counter-current imbibition

We also performed a series of two-dimensional (2D) simulations to check the validity of our 1D results. The grid system used is shown in Fig. 2.13. A total of 115,235 fine grid blocks were used. Sensitivity studies using 90,000 and 160,000 grid blocks demonstrated that we used sufficient grid blocks to obtain converged results. Fig. 2.14 shows the results for both sets of relative permeabilities. For the 2D simulations, including gravity had no effect on the results. Again the agreement with experiments is good, particularly at early times. The results are similar to those obtained in 1D, Figs. 2.10 and 2.12.

Fig. 2.13. Grid system used for the 2D counter-current imbibition simulations. A total of 115,236 grid blocks were used.
Fig. 2.14. Comparison of 2D counter-current imbibition simulations using Bourbiaux & Kalaydjian\textsuperscript{18} data (Fig. 2.3) and network model properties, (Fig. 2.11) with literature experimental data.

2.4. Validity of the scaling functions, Eqs. (1.8) and (1.11)

The dimensionless time, Eq. (1.8), can be derived using dimensional analysis. However, the scaling with viscosity is not obvious. The first authors\textsuperscript{54} to study this problem suggested $t_D$ should be inversely proportional to the water viscosity, while a recent analytical approach suggests that $t_D$ is inversely proportional to the oil viscosity\textsuperscript{70}. The scaling in Eq. (1.8) involving the geometric average of the oil and water viscosities was suggested based on experimental results for systems with different viscosity ratio\textsuperscript{52}. The Zhou et al.\textsuperscript{80} scaling equation include the mobility of wetting and non-wetting phase. To check the validity of the Ma et al.\textsuperscript{52} and Zhou et al.\textsuperscript{80} scaling functions, Eqs. (1.8) and (1.11), a series of 1D-simulations for different oil to water viscosity ratios were performed using the network model derived data\textsuperscript{41}. The experiments by Zhang et al.\textsuperscript{79} covered a range of viscosity ratios from 4 to 160 – in our simulations a range from 0.01 to 200 was used. The
recovery from the simulations plotted as a function of the dimensionless time, Eq. (1.8), is shown in Fig. 2.15. While it is evident that all the recoveries do not fall exactly on the same universal curve, there is little scatter in the results. In contrast using either the oil viscosity (Fig. 2.16) or the water viscosity (Fig. 2.17) only in the definition of dimensionless time and also Eq. (1.11), (Fig. 2.18) leads to a much larger scatter in the curves, verifying that Eq. (1.8) is at least approximately correct as the scaling function. These results confirm previous analytical and experimental studies by Ruth et al.\textsuperscript{63} and Li et al.\textsuperscript{50}.

A similar study of a wide range of dimensionless groups is presented in the Appendix-B of this chapter. This study also shows that the time-scale for recovery in water-wet systems is proportional to the geometric mean of the oil and water viscosities. However for the cases where the viscosity of one phase approaches zero (e.g. a gas phase), the geometric mean of the viscosities in the denominator will be zero therefore the Ma et al.\textsuperscript{52} correlation, Eq. (1.8) is only valid for a finite range of viscosity ratios.

Fig. 2.15. Effect of different oil to water viscosity ratios, $M$, on the results of 1D simulations using network model derived data. All curves are correlated based on the Ma et al.\textsuperscript{52} scaling function, Eq. (1.8). Notice that all the plots approximately fall onto a single curve, validating the scaling group.
Fig. 2.16. Using only the oil viscosity in the definition of dimensionless time leads to a large scatter in the results from 1D simulations with different oil to water viscosity ratios, $M$, using network model derived data.

Fig. 2.17. Using only water viscosity in the definition of dimensionless time leads to a large scatter in the results from 1D simulations with different oil to water viscosity ratios, $M$, using network model derived data.
Fig. 2.18. Using Zhou et al.\textsuperscript{80} dimensionless time, Eq. (1.11) leads to a scatter in the results from 1D simulations with different oil to water viscosity ratios, $M$, using network model derived data.

2.5. Theory and simulation of fracture flow and imbibition

We have shown that it is possible to predict the behaviour of imbibition experiments using a traditional Darcy-type formulation for the flow equations. In the experiments the matrix was surrounded by an effectively infinite reservoir of water. We will now study cases where water flows in a fracture in addition to imbibing into the matrix.

2.5.1 Experimental results

It was discussed (in sec. 1.2.2, ch.1) that Rangel-German and Kovscek\textsuperscript{61} investigated the rate of fracture to matrix transfer and the pattern of wetting fluid imbibition using CT scanning. Their experiments with different flow rates and fracture apertures illustrated two different flow regimes. When the flow in the fractures was slow, there was a frontal advance in both matrix and fracture – this
was called the filling-fracture regime and the amount of water in the matrix increased linearly with time. At higher fracture flow rates, water in the fracture moved ahead of water in the matrix. This was called the instantly-filled regime and the amount of water in the matrix increased with the square root of time.

2.5.2 Theory for dual porosity systems

At the field scale, flow in fractured reservoirs is simulated using a dual porosity approach\textsuperscript{13,76}, where conceptually the reservoir is composed of two domains: a flowing fraction, representing the fractures; and a relatively stagnant matrix. Transfer of fluid between fracture and matrix is represented by a transfer function.

We derive an empirical transfer function based on the Ma et al.\textsuperscript{52} expression for water-wet data, Eq. (1.10). For incompressible flow of oil and water in 1D the conservation equations for water are\textsuperscript{28,47} (Appendix-C):

\begin{align}
\phi_f \frac{\partial S_{wf}}{\partial t} + v_i \frac{\partial f_{wf}}{\partial x} + g_x \frac{\partial G}{\partial x} &= -T \\
\phi_m \frac{\partial S_{wm}}{\partial t} &= T
\end{align}

where the subscript \(f\) stands for flowing or fracture and \(m\) for matrix, representing the stagnant fraction. \(v_i\) is the total velocity. \(f_{wf}\) is the water fractional flow in the flowing fraction ignoring gravity:

\[
f_{wf} = \frac{\lambda_{wf}}{\lambda_{wf} + \lambda_{of}}
\]

and:

\[
G = (\rho_w - \rho_o)Kf_{wf} \lambda_{of}
\]

\(T\) is the transfer function that represents the rate at which water transfers from flowing to stagnant regions.
De Swaan\textsuperscript{26,27}, Kazemi et al.\textsuperscript{47} and DiDonato et al.\textsuperscript{28} have developed transfer functions that reproduce the exponential functional form – Eq. (1.9) – that matches imbibition experiments. If we view $S_{wm}$ as the average saturation in the matrix, we can write:

\[
\frac{R}{R_\infty} = \frac{S_{wm} - S_{wmi}}{1 - S_{omr} - S_{wmi}}
\]

(2.6)

where $S_{wmi}$ is the initial water saturation in the matrix and $S_{omr}$ is the corresponding residual oil saturation. Thus from Eq. (1.10):

\[
S_{wm} = S_{wmi} + \left(1 - S_{omr} - S_{wmi}\right)(1 - e^{-\alpha_p})
\]

(2.7)

Then from Eq. (2.7):

\[
\phi_m \frac{\partial S_{wm}}{\partial t} = T = \alpha \frac{t \phi_m}{t} \left(1 - S_{omr} - S_{wm}\right)
\]

(2.8)

\[
= \beta \phi_m \left(1 - S_{omr} - S_{wm}\right)
\]

where the rate constant $\beta$ is defined by Eq. (2.8).

In the core flood experiments the effective fracture saturation was held at 1. In our simulations, the fracture saturation may be lower. DiDonato et al.\textsuperscript{28} assumed that the transfer function is independent of the flowing saturation, as long as $S_{w0} > 0$. This is consistent with assuming that the capillary pressure in the low permeability matrix is much higher than in the fractures – the driving force for imbibition is the matrix capillary pressure and imbibition continues until the matrix and fracture capillary pressures are equal – when $S_{w0} = 0$ and $S_{wm} = 1 - S_{omr}$. Thus we take:

\[
T = \beta \phi_m \left(1 - S_{omr} - S_{wm}\right) S_{wf} > 0
\]

\[
= 0 \quad S_{wf} = 0
\]

(2.9)

Note that the transfer function is a linear function of the matrix saturation.
de Swaan\textsuperscript{26,27} derived a similar transfer function to Eq. (2.8) when $S_{wf} = 1$. For $S_{wf} < 1$ he used a convolution integral, Eq. (1.33) to compute the matrix saturation. This is consistent with using:

$$T = \beta \phi_n (S_{wf} (1 - S_{comr} - S_{wm}) - (S_{wm} - S_{wm}))$$  \hfill (2.10)

A similar expression was derived by Kazemi et al.\textsuperscript{47}, Eq. (1.39) from de Swaan's\textsuperscript{26} convolution integral, Eq. (1.33). This formulation is correct if the large-scale fracture saturation is viewed as being an average of fully saturated fractures undergoing imbibition and completely dry fractures. However, for uniformly partially saturated fractures, imbibition ceases when the fracture and matrix saturations are proportional to each other, implying similar values of the fracture and matrix capillary pressures. This is rarely correct, and certainly inconsistent with the basic premise of dual porosity models that there is a huge disparity in permeability between flowing and stagnant regions. This transfer function is also linearly dependent on saturation.

### 2.5.3 Grid-based simulation of fracture/matrix flow

We construct a 2D model of a fracture and matrix. The purpose is to determine:

1. if we can reproduce the behaviour observed experimentally by Rangel-German and Kovscek\textsuperscript{61} and
2. if the same results can be obtained using a 1D simulation to solve Eqs. (2.2) and (2.3) with an appropriate transfer function.

The model consists of a horizontal fracture (Tables 2.4 and 2.5) initially filled with oil ($S_{wf} = 0$ at $t=0$) connected from both sides to oil saturated matrix blocks ($S_{wm} = S_{wc}$ at $t=0$). Here the fracture is defined explicitly as a high permeability region with a porosity of 1, and no transfer function is used (Fig. 2.19). There are 122 matrix grid blocks along the fracture. The matrix length and grid system in the direction perpendicular to the fracture is exactly the same as those used to simulate counter-current imbibition in 1D (Fig. 2.2) that matched the experimental results. The system is 244 cm long and has a width of 56.7 cm. The fracture aperture is 0.7 cm (Table 2.5). Water is injected at a constant rate via an injection well into the
first grid block of the fracture and liquid (oil and water) is produced at a constant pressure from a producing well that is completed in the last fracture grid block.

Table 2.4. Fracture properties used in 2D fracture/matrix simulations.

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial water saturation</td>
<td>fraction</td>
<td>0.0</td>
</tr>
<tr>
<td>Porosity</td>
<td>fraction</td>
<td>1.0</td>
</tr>
<tr>
<td>Capillary pressure</td>
<td>Pa</td>
<td>0.0</td>
</tr>
<tr>
<td>Permeability</td>
<td>m$^2$</td>
<td>$15 \times 10^{-12}$</td>
</tr>
</tbody>
</table>

$k_{rw} = S_w^2$

$k_{ro} = (1 - S_w)^2$

Table 2.5. Dimensions of the model in 2D fracture/matrix simulations

<table>
<thead>
<tr>
<th>Unit</th>
<th>Fracture</th>
<th>Matrix (on either side of the fracture)</th>
</tr>
</thead>
<tbody>
<tr>
<td>X</td>
<td>cm</td>
<td>.7</td>
</tr>
<tr>
<td>Y</td>
<td>cm</td>
<td>244</td>
</tr>
<tr>
<td>Z</td>
<td>cm</td>
<td>1</td>
</tr>
</tbody>
</table>

Fig. 2.19. Grid system used for the 2D fracture/matrix simulation. The grid perpendicular to the fracture direction is exactly as in Fig. 2.2 – the darker area indicates finer grids close to the fracture.
The matrix porosity, relative permeabilities and matrix connate and residual saturations come from Bourbiaux and Kalaydjian\(^1\) (Table 2.2). In order to produce a situation similar to fractured carbonate reservoirs the matrix absolute permeability is reduced from 124 md to 1 md to ensure a huge disparity in permeability between fracture and matrix. The matrix capillary pressure has the same functional form as used by Bourbiaux and Kalaydjian\(^1\), but increased by the square root of the ratio of the experimental permeability to the model matrix permeability. This is standard Leverett \(J\) function scaling\(^5\). The viscosities of the oil and water are assumed to be equal to \(1.5 \times 10^{-3}\) Pa.s. Capillary pressure in the fracture is assumed to be zero. Fracture permeability is set to \(15 \times 10^{-12}\) m\(^2\) (15 Darcy). Quadratic relative permeabilities are defined in the fracture (Table 2.4) - to reduce numerical dispersion in the simulation results. This means that a shock develops in the 1D displacement in the fracture.

Two water injection rates of 20 cc/hr and 2 cc/hr are used. Based on the fracture volume, a high injection rate was selected to predict the imbibition pattern when the fracture fills rapidly with water. The lower injection rate was selected to predict imbibition behaviour when a considerable amount of time is needed for water to fill the fracture. We also ran two other simulations for comparison purposes. First, we consider a case with no matrix for an injection rate of 20 cc/hr. The results are compared with an analytical solution based on the Buckley-Leverett approach\(^25\) and 1D numerical solutions using the streamline code described by DiDonato et al.\(^28\) Second we ran a similar case, but the matrix is defined with a matrix capillary pressure of zero. This test shows the effect of viscous forces on the recovery process.

### 2.5.4 Analytical solutions and 1D numerical solutions

Fig. 2.20 shows a comparison of numerical solutions for a simulation with no matrix compared to the analytic Buckley-Leverett solution\(^25\). The agreement between the numerical and analytical results confirms that both Eclipse and the streamline code can accurately reproduce a 1D displacement.
Fig. 2.21 shows the fracture saturation when there is no capillary pressure in the matrix. The results are compared to the analytic solution where there is no matrix. The agreement between the two simulations indicates that viscous forces alone have little effect on the fracture/matrix transfer. This result agrees experimental results of Babadagli and Tang and Firoozabadi (sec. 1.2.3, ch.1).

In both cases in Figs 2.20 and 2.21, the saturation profiles in the fracture are similar for all time step.

We will now compare the results of 2D simulations with a finite matrix capillary pressure with 1D dual porosity models. The linear transfer functions developed by DiDonato et al., Eq. (2.9) and Kazemi, Eq. (1.39) will be used in a dual porosity model. In the dual porosity model the following equations are used to define fracture and matrix porosities and the effective permeability of the system from the geometry of the 2D explicit fracture model:

\[
\phi_f = \frac{W_f}{W_f + W_m} \quad (2.11)
\]

\[
\phi_m = \frac{\phi_m W_m}{W_f + W_m} \quad (2.12)
\]

\[
K_{eff} = \frac{W_f K_f + W_m K_m}{W_f + W_m} \quad (2.13)
\]

where \(W\) and \(K\) are the width and permeability respectively and the subscripts \(f\) and \(m\) refer to fracture and matrix. The total velocity in the 1D dual porosity simulation is calculated using the following equation:

\[
v_t = \frac{Q}{W_f H} \quad (2.14)
\]

Where \(Q\) is the injection rate and \(W_f\) is the fracture aperture and \(H\) is the system thickness. Tables 2.6 and 2.7 give the data used in the dual porosity simulations.
Fig. 2.20. Comparison of fracture water saturations for 1D simulations with no matrix present after 3 and 5 hours. The Buckley-Leverett analytical solution (dotted line) is compared to numerical simulation results using a commercial reservoir simulator (solid line) and a streamline-based model (dashed line). The good agreement shows that simulations can accurately reproduce a 1D displacement.

Fig. 2.21. Numerical simulations of fracture flow after 2 and 4 hours. The solid lines show the fracture saturation for flow with matrix present and no capillary pressure. The dotted lines are Buckley-Leverett analytical solutions assuming a purely 1D displacement with no matrix. The agreement between the two simulations indicate that viscous forces in this water-wet model have little effect on the fracture/matrix transfer.
Table 2.6. Data used in the 1D dual porosity simulations.

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fracture porosity, $\phi_f$</td>
<td>fraction</td>
<td>0.012</td>
</tr>
<tr>
<td>Matrix porosity, $\phi_m$</td>
<td>fraction</td>
<td>0.233</td>
</tr>
<tr>
<td>Fracture permeability, $K_f$</td>
<td>$m^2$</td>
<td>$15 \times 10^{-12}$</td>
</tr>
<tr>
<td>Matrix permeability, $K_m$</td>
<td>$m^2$</td>
<td>$10^{-15}$</td>
</tr>
<tr>
<td>Matrix initial water saturation, $S_{swi}$</td>
<td>fraction</td>
<td>0.40</td>
</tr>
<tr>
<td>Matrix residual oil saturation, $S_{swr}$</td>
<td>fraction</td>
<td>0.422</td>
</tr>
<tr>
<td>Water density, $\rho_w$</td>
<td>Kg.m$^{-3}$</td>
<td>1090</td>
</tr>
<tr>
<td>Oil density, $\rho_o$</td>
<td>Kg.m$^{-3}$</td>
<td>760</td>
</tr>
<tr>
<td>Water viscosity, $\mu_w$</td>
<td>Pa.s</td>
<td>$1.5 \times 10^{-3}$</td>
</tr>
<tr>
<td>Oil viscosity, $\mu_o$</td>
<td>Pa.s</td>
<td>$1.5 \times 10^{-3}$</td>
</tr>
<tr>
<td>Fracture/Matrix rate constant, $\beta$</td>
<td>days$^{-1}$</td>
<td>0.08423</td>
</tr>
<tr>
<td>Fracture water relative permeability</td>
<td></td>
<td>$k_{ref} = S_w^2$</td>
</tr>
<tr>
<td>Fracture oil relative permeability</td>
<td></td>
<td>$k_{ref} = (1 - S_w)^2$</td>
</tr>
</tbody>
</table>

Table 2.7. Equivalent injection data used in 1D dual porosity simulations.

<table>
<thead>
<tr>
<th></th>
<th>Unit</th>
<th>High injection rate case</th>
<th>Low injection rate case</th>
</tr>
</thead>
<tbody>
<tr>
<td>2D- Injection rate, $Q_{2D}$</td>
<td>cc.hr$^{-1}$</td>
<td>20</td>
<td>2</td>
</tr>
<tr>
<td>2D- Total velocity, $V_t$</td>
<td>m.s$^{-1}$</td>
<td>$7.94 \times 10^{-5}$</td>
<td>$7.94 \times 10^{-6}$</td>
</tr>
<tr>
<td>1D- Injection rate, $Q_{1D}$</td>
<td>m$^3$.day$^{-1}$</td>
<td>$4.6676 \times 10^{-4}$</td>
<td>$4.6676 \times 10^{-5}$</td>
</tr>
</tbody>
</table>
2.5.5. **Analysis of the results**

Figs. 2.22 and 2.23 show the comparison of the simulated water saturation profiles in the fracture and matrix for different time-steps for an injection rate of 20 cc/hr. Due to the high injection rate it is expected that the front moves very fast in the fracture and most imbibition take places when the average water saturation in the fracture is nearly one. Since the amount of transfer is small at early time, the fracture saturation profiles for all three simulations are similar.

![Fracture Water Saturation vs Distance](image)

Fig. 2.22. Simulated fracture water saturation for $Q=20$ cc/hr after 3, 5 and 7 hours. 2D simulation (solid line) is compared with a 1D dual porosity model using a transfer function due to either DiDonato et al.\(^{28}\) (dashed line) or Kazemi et al.\(^{47}\) (dotted line).

The simulated matrix saturation profiles are different, however, with the dual porosity models predicting more transfer into the matrix than the 2D simulation. This is simply because the transfer functions reproduce the empirical fit, Eq. (1.10) that gives a higher recovery than the equivalent 1D simulations. The results for 240 hours correspond to a dimensionless time $t_D$ of 17. It is clear from a comparison of Fig. 2.5 that at this time the simulations do indeed predict a lower recovery than the experimental correlation, Eq. (1.10), for 1D counter-current imbibition. DiDonato et al.’s\(^{28}\) transfer function shows little change in matrix saturation with distance, similar to the 2D simulations, while the Kazemi et al.\(^{47}\)
function predicts a significant change in saturation with distance. This is because Kazemi et al.'s\textsuperscript{47} model predicts less transfer into the matrix when the fracture saturation is less than 1 – that is near the outlet.

Fig. 2.24 shows the average matrix saturation as a function of time. The average saturation scales with the square root of time, except at late time, which was also observed experimentally for the instantly-filled fracture regime\textsuperscript{61}. 

![Diagram showing matrix water saturation as a function of distance for different transfer functions.](image)

Fig. 2.23. Simulated matrix water saturation for a flow rate of 20 cc/hr after 100 and 240 hours. 2D simulation (solid line) is compared with a dual porosity model using a transfer function due to either DiDonato et al.\textsuperscript{28} (dashed line) or Kazemi et al.\textsuperscript{47} (dotted line). The 2D simulation and the Di Donato et al.\textsuperscript{28} transfer function show a flat profile similar to that observed experimentally\textsuperscript{61}. 

*Analysis, Scaling and Simulation of Counter-Current Imbibition*  
H. Sh. Behbahani
Fig. 2.24. The simulated average matrix water saturation in the 2D simulation scales linearly with the square root of time for a flow rate of 20 cc/hr and reproduces the behaviour of the instantly-filled regime in Rangel-German and Kovscek's experimental results.

Figs. 2.25 and 2.26 compare the simulated water saturation profiles in the fracture and matrix at different times for an injection rate of 2 cc/hr. In this case water advances in the fracture and matrix at comparable rates. In contrast to the previous case, the simulated fracture saturation profiles are not the same for the different models. The simulated matrix saturation profiles are also different. Fig. 2.5 reveals that at early time ($t_D$ of less than approximately 5, or a real time of approximately 70 hours) the simulations predict a higher recovery than Eq. (1.10), while for intermediate and late times (greater than around 70 hours) the simulations predict lower recovery. In our 2D simulations this relates to the recovery (or water saturation) in the matrix. Hence we expect that at early times the dual porosity models will give lower recovery in the matrix and higher recovery at late times. This is evident in Fig. 2.26. If there is less imbibition into the matrix, more water is retained in the fracture and the water front in the fracture moves faster. This is confirmed in Fig. 2.25 where the water saturation in the fracture is moving faster for the dual porosity models as a consequence of the lower matrix recoveries. The water advance is still greater at 70 hours, which is just in the late time regime.
However, most of the matrix has been next to a water-filled portion of the fracture for considerably less than 70 hours, so the results are still consistent with the early time behaviour.

Fig. 2.25. The fracture water saturation for a flow rate of 2 cc/hr after 30 and 70 hours. 2D simulation (solid line) is compared to dual porosity models using the DiDonato et al. (dashed line) and Kazemi et al. (dotted line) transfer functions.

Fig. 2.26. The matrix water saturation for a flow rate of 2 cc/hr after 48 and 240 hours. Results from 2D simulation are compared to dual porosity models using the DiDonato et al. (dashed line) and Kazemi et al. (dotted line) transfer functions.
Another possible explanation for the discrepancy in the results is that the 2D simulations allow co-current flow, whereas the transfer functions are based on counter-current flow, which is slower. In the 2D simulations oil can travel in a direction parallel to water towards the high permeability fracture and/or un-drained matrix grid blocks, resulting in more rapid recovery than from counter-current imbibition alone. However, a careful quantitative analysis of the results shows that this does not affect recovery in this case, and that the differences between the results are explained solely by the differences in predicted 1D counter-current recovery. For instance, Fig. 2.26 shows that the water saturation at the inlet after 48 hours is 43.5 percent in the 2D simulations and 42.8 percent using the DiDonato et al.\textsuperscript{28} model. 48 hours corresponds to $t_D$ of 3.4. Using Fig. 2.5 to find the oil recovery assuming counter-current flow only for the simulations and using Eq. (1.10) will lead to exactly the same water saturations. This shows that co-current imbibition has no effect on the results. This is likely to be due to the extreme contrast in matrix and fracture permeabilities.

The Kazemi et al.\textsuperscript{47} transfer function always gives a transfer rate that is less than or equal to that predicted by the DiDonato et al.\textsuperscript{28} model. As a consequence the Kazemi et al.\textsuperscript{47} model predicts less transfer into the matrix and a more diffuse and further advanced saturation profile in the fracture. Qualitatively the 2D simulations give profiles more similar to the DiDonato et al.\textsuperscript{28} model, since in both cases a zero fracture capillary pressure is assumed.

Overall the DiDonato et al.\textsuperscript{28} dual porosity model gives similar results to direct 2D simulation, indicating that a dual porosity approach can properly simulate fracture/matrix flow in a simple system. The differences in the results can all be explained by considering the differences in the predictions of counter-current imbibition with no fracture flow. It should be possible to adjust the rate constant $\beta$ to obtain a better match between the dual porosity and 2D simulation models, but this would simply be a matching exercise with little physical validity.

Fig. 2.27 shows the average matrix water saturation as a function of time. The average saturation scales approximately linearly with time at early times (less than
around 200 hours), which was also observed experimentally for the filling-fracture regime\textsuperscript{61}.

Fig. 2.27. The simulated average matrix water saturation in 2D simulation scales approximately linearly with time at early times (less than 200 hours) for a flow rate of 2 cc/hr and reproduces the behaviour of the filling-fracture regime in Rangel-German and Kovscek's\textsuperscript{61} experimental results.

Penuelas et al.\textsuperscript{58} developed a transfer function for dual porosity simulation that matched fine grid simulations of imbibition. They used a transfer function with the same definition of shape factor used conventionally by Kazemi et al.\textsuperscript{47} but allowed the shape factor to be time-dependent. In comparison, our formulation matches experiment, is mathematically simpler, and physically more appealing, since the governing partial differential equations are written as a function of saturation. However we only consider incompressible two-phase flow, whereas Penuela et al.\textsuperscript{58} also considered compressibility.

Rangel-German and Kovscek\textsuperscript{62} also proposed a time-dependent shape factor to match their experimental results. They found a formulation that matched the overall recovery for different flow rates. However, in essence they upscaled a 2D system to a zero-dimensional average property. Our dual porosity model upscales a
2D or 3D system into a 1D problem along the flow direction. Their formulation – except for the representation of a time rather than a saturation dependent shape factor – is broadly equivalent to Kazemi et al.'s transfer function. As we have shown, when placed in a dual porosity model, this transfer function underestimates the matrix recovery and overestimates the water advance rate in the fractures. Our formulation is identical to theirs for a constant shape factor.

2.6. Conclusions

It is shown that:

1. Simulation of one-dimensional and two-dimensional counter-current imbibition matched the results of core experiments. This confirms that a conventional Darcy treatment of multiphase flow is adequate to describe counter-current imbibition if appropriate relative permeabilities and capillary pressures are used. Our results will suggest that an approach describing multiphase flow with rate dependent coefficients although intriguing, is not necessary to predict the experiments.

2. The validity of the Ma et al. and Zhou et al. scaling functions, Eqs. (1.8) and (1.11) was tested by performing simulations for different oil/water viscosity ratios using network model derived data. The results indicated that recovery plots for different viscosity ratios could be scaled onto the same curve using a dimensionless time that is inversely proportional to the geometric mean of the water and oil viscosities, as established experimentally.

3. The results of 2D simulations of flow in a long fracture connected to a horizontal water-wet matrix show the same flow regimes as observed experimentally by Rangel-German and Kovscek.

4. Using a 1D dual porosity model with a transfer function that matched core-scale imbibition experiments was able to reproduce the same behaviour observed using explicit 2D simulation of fracture/matrix flow.
2.7. Appendix-A

Derivation of Eq. (2.1)

The one-dimensional Darcy equations for the flow of water and oil are:

\[ u_w = -K\lambda_w \left( \frac{\partial P_w}{\partial x} - \rho_w g_x \right) \quad (A.1) \]

\[ u_o = -K\lambda_o \left( \frac{\partial P_o}{\partial x} - \rho_o g_x \right) \quad (A.2) \]

where \( K \) is absolute permeability, \( \lambda \) is mobility, \( P \) is pressure, \( \rho \) is density and \( g_x \) is the component of gravity in the flow direction. Assuming no overall flow:

\[ u_w + u_o = 0 \quad (A.3) \]

\[ P_c = P_o - P_w \quad (A.4) \]

\[ \lambda_t = \lambda_o + \lambda_w \quad (A.5) \]

Substituting water and oil velocities from Eqs. (A.1) and (A.2) into Eq. (A.3) and solving for the derivative of water pressure considering Eqs. (A.4) and (A.5) will lead to:

\[ \frac{\partial P_w}{\partial x} = -\frac{\lambda_t}{\lambda_w} \frac{\partial P_c}{\partial x} - \frac{\lambda_0}{\lambda_t} \rho_o g_x - \frac{\lambda_w}{\lambda_t} \rho_w g_x \quad (A.6) \]

Substituting Eq. (A.6) into Eq. (A.1), the water velocity can be expressed in terms of the oil-water capillary pressure:
The one-dimensional equation for conservation of water assuming incompressible flow and no source or sink is:

\[
\phi \frac{\partial S_w}{\partial t} + \frac{\partial u_w}{\partial x} = 0
\]  \hspace{1cm} (A.8)

Substituting the water velocity from Eq. (A.7) into Eq. (A.8) will lead to Eq. (2.1):

\[
\phi \frac{\partial S_w}{\partial t} + \frac{\partial}{\partial x} \left[ \frac{\lambda_w \lambda_0}{\lambda_i} K \left( \frac{\partial P_c}{\partial S_w} \frac{\partial S_w}{\partial x} + g_x (\rho_w - \rho_o) \right) \right] = 0
\]  \hspace{1cm} (A.9)
2.8. Appendix-B

Study of validity of various scaling groups with water-wet data

The dimensionless groups shown in Table B.1 were also derived and tested to scale the imbibition recovery in water-wet media for various oil to water viscosity ratios, $M$ between .01 to 200. The results of imbibition predictions (sec. 2.4, ch. 1) using pore-scale data\(^1\) are used for this comparison. In all cases, relative permeabilities are end points, that is oil relative permeability at initial water saturation, $S_{wi}$ and water relative permeability at residual oil saturation, $S_{or}$. The results of scaling for each scaling group are illustrated in Figs. B.1 to B.9.

The dimensionless group shown in Fig. B.9 gives similar results to the Ma et al.\(^2\) scaling equation, Eq. (1.8). Including the water and oil mobilities reduces the dimensionless time about one order of magnitude if Fig. B.9 and Fig. 2.15 are compared.

This study shows that the time-scale for recovery in water-wet systems for finite viscosities is proportional to the geometric mean of the oil and water viscosities, as shown by Ma et al.\(^2\)
Table B.1. List of the tested dimensionless groups and the figures that illustrate the results.

<table>
<thead>
<tr>
<th>Dimensionless group</th>
<th>Figure</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \lambda_{rw}^*$</td>
<td>Fig. B.1</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \lambda_{ro}^*$</td>
<td>Fig. B.2</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} k_{ro} \lambda_{rw}^*$</td>
<td>Fig. B.3</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \lambda_{rw}^*$</td>
<td>Fig. B.4</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \frac{\lambda_{rw}^<em>}{\sqrt{M^</em>} + \frac{1}{\sqrt{M^*}}}$</td>
<td>Fig. B.5</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \frac{\lambda_{rw}^<em>}{1 + \frac{1}{M^</em>}}$</td>
<td>Fig. B.6</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \frac{\lambda_{ro}^<em>}{\sqrt{M^</em>} + \frac{1}{\sqrt{M^*}}}$</td>
<td>Fig. B.7</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \frac{\lambda_{ro}^<em>}{M^</em>}$</td>
<td>Fig. B.8</td>
</tr>
<tr>
<td>$t_D = t \sqrt{\frac{K \sigma}{\phi L_c^2}} \frac{\lambda_{rw}^* \lambda_{ro}^<em>}{\sqrt{M^</em>}}$</td>
<td>Fig. B.9</td>
</tr>
</tbody>
</table>
Fig. B.1. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled using water mobility alone.

Fig. B.2. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled using oil mobility alone.
Fig. B.3. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled using oil relative permeability and water mobility.

Fig. B.4. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled using water mobility and mobility ratio.
Fig. B.5. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled including the effect of water mobility and mobility ratio.

Fig. B.6. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled including the effect of water mobility and mobility ratio.
Fig. B.7. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled including the effect of oil mobility and mobility ratio.

Fig. B.8. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, cannot be scaled including the effect of oil mobility and mobility ratio.
Fig. B.9. Imbibition recoveries in water-wet rock for different viscosity ratios, $M$, can be scaled using oil and water mobilities. The quality of scaling is similar to Ma et al. scaling group, Eq. (1.8), Fig. 2.15.
2.9. Appendix-C

Derivation of Eqs. (2.2) and (2.3)

The one-dimensional Darcy equations for incompressible flow of water and oil in the fracture are:

\[ \frac{\partial P}{\partial x} = -K \lambda_{wf} \left( \frac{\partial P_{wf}}{\partial x} - \rho_w g_x \right) \]  \hspace{1cm} (C.1)

\[ \frac{\partial P}{\partial x} = -K \lambda_{of} \left( \frac{\partial P_{of}}{\partial x} - \rho_o g_x \right) \]  \hspace{1cm} (C.2)

where \( K \) is absolute permeability, \( \lambda \) is mobility, \( P \) is pressure, \( \rho \) is density and \( g \) is the component of gravity in the flow direction. If there is no capillary pressure in the fracture, total water and oil mobility and water fractional flow can be expressed by:

\[ u_{wf} + u_{of} = v_t \hspace{1cm} (C.3) \]

\[ P_{cf} = 0 \Rightarrow P_{of} = P_{wf} = P \hspace{1cm} (C.4) \]

\[ \lambda_t = \lambda_o + \lambda_w \hspace{1cm} (C.5) \]

\[ f_{wf} = \frac{\lambda_{wf}}{\lambda_t} \hspace{1cm} (C.6) \]

Substituting water and oil velocities from Eqs. (C.1) and (C.2) into Eq. (C.3) and solving for the derivative of pressure considering Eqs. (C.4) and (C.5) will lead to:
Substituting Eq. (C.7) into Eq. (C.1) and considering Eq. (C.6), the water velocity can be expressed in terms of total velocity and the water fractional flow:

\[ u_{wf} = (f_{wf} v_i + g_x K_{wf} \frac{A_{wf}}{A_i} (\rho_w - \rho_o)) \]  

The one-dimensional equation for conservation of water with \( T \) as the source term for the fracture is:

\[ - \frac{\partial u_{wf}}{\partial x} = \phi_f \frac{\partial S_{wf}}{\partial t} + T \]  

Substituting the water velocity from Eq. (C.8) into Eq. (C.9) will lead to Eq. (2.2):

\[ \phi_f \frac{\partial S_{wf}}{\partial t} + v_i \frac{\partial f_{wf}}{\partial x} + g_x \frac{\partial G}{\partial x} = -T \]

The one-dimensional equation for water volume change in the matrix is:

\[ \phi \frac{\partial S_w}{\partial t} = T \]

This is Eq. (2.3).
Summary

In this chapter quasi-static pore-scale modelling will be used to study counter current imbibition in mixed-wet fractured reservoirs to explain why experimentally it is observed that imbibition is several orders of magnitude slower in mixed-wet media than in water-wet systems. The result of this analysis will be used to present a semi-empirical correlation for scaling of imbibition in mixed-wet rocks with different wettability states.

3.1. Introduction

It was shown (sec. 1.4.3, ch.1) that imbibition in mixed-wet rocks has three characteristics: (1) mixed-wet rocks are able to imbibe both water and oil,\(^5_{,19,35}\), (2) an induction time is observed experimentally and imbibition is several orders of magnitude slower than in water-wet rocks\(^5_{,70,81}\) and (3) initial water saturation has a significant effect on oil recovery\(^43_{,55,70,81}\).

As mentioned previously, (sec. 1.4.3, ch. 1) Zhou et al.\(^81\) presented the results of counter-current spontaneous imbibition and water-flood experimental data for different initial water saturations, corresponding to different wettabilities. Counter-current spontaneous imbibition recovery was measured by the change in weight of the aged samples that were hung in a degassed brine solution. In flooding tests, the samples at initial water saturation were flooded at slow rates. The water-floods were stopped when the water-oil ratio, \(r_{wo}\), was greater than 99.

The results of imbibition and water-flooding tests from Zhou et al.\(^81\) are illustrated in Fig. 3.1 for \(S_{wi} = 0.15\). The longer the aging time, the more oil-wet the core.
becomes. The recovery rate from imbibition at mixed-wet conditions was several orders of magnitude slower than for water-wet conditions, where the core was not aged at all.

It can be seen that as the aging time increases, corresponding to more oil-wet conditions, the induction time increases.

Zhou et al.\textsuperscript{81} used Eq. (1.8) to correlate the result of spontaneous imbibition in mixed-wet core samples (Fig. 1.54, sec. 1.4.3, ch.1). They stated that the difference between the reference curve for strongly water-wet cores and the data for various aging times is due primarily to wettability.

Gupta and Civan\textsuperscript{36}, Cil et al.\textsuperscript{22} and Zhou et al.\textsuperscript{81} included the effect of different wettability states in the definition of dimensionless time, Eq. (1.8) using a single parameter of $\cos \theta$ where $\theta$ represents effective contact angle of the system [Eqs. (1.16) to (1.18), sec. 1.4.4, ch. 1]. Since the cores are mixed-wet, there are water-wet and oil-wet regions of the pore space, and assignment of a single effective contact angle is an empirical fit to the data which does not represent a typical contact angle in the porous medium.

A more fundamental approach to understanding imbibition in mixed-wet systems is the use of pore-scale network modelling. Pore-network models have been used to describe a wide range of properties from capillary pressure characteristics to interfacial area and mass transfer coefficients\textsuperscript{18,42}. We apply pore-scale modelling to analyse counter-current imbibition in mixed-wet rocks. The model will be used to predict relative permeability and capillary pressure for different wettabilities. The contact angles will be chosen to match the results of co-current water-flood absolute recoveries and the measured wettability indices. Then the relative permeabilities and capillary pressure will be input into a conventional grid-based simulator to predict counter-current imbibition in one dimension and the results will be compared to experimental results. This work will enable us to identify the physical origin of the slow recoveries seen experimentally and to probe the necessity of introducing an induction time into a quantitative analysis of the results.
Fig. 3.1. Experimental recovery data on Berea cores aged in crude oil for different aging times, $t_a$, from Zhou et al.\textsuperscript{81} for $S_{wi}=15\%$ (a) Oil recovery by spontaneous imbibition and (b) Oil recovery by water-flooding.
3.2. Network modelling

In network modelling, the void space of a rock is represented at the microscopic scale by a lattice of pores connected by throats. Rules are developed to determine the multiphase fluid configurations and transport in these pores and throats. The appropriate pore-scale physics combined with a geologically representative description of the pore space gives a model that can predict average behaviour, such as capillary pressure and relative permeability. The model we use accounts for wetting layers in crevices of the pore space, cooperative pore filling and different contact angles.

A two-phase mixed-wet pore-scale model was used in this work that uses networks based on real rocks and simulates primary drainage, wettability alteration and any subsequent cycles of water-flooding and secondary drainage. The model is quasi-static, in that it ignores dynamic effects at the pore scale. The model is described in more detail elsewhere – here we simply use it to compute relative permeabilities and capillary pressures for different wettabilities. A three-dimensional voxel representation of Berea sandstone is the basis for the networks used in the code. From this voxel representation a topologically equivalent network of pores and throats (in terms of volume, throat radii, clay content etc) can then be extracted. The cross-sectional shape of the network elements (pores and throats) is a circle, square or triangle with the same shape factor (ratio of cross-sectional area to perimeter length squared) as the voxel representation. Fairly smooth pores with a high shape factor will be represented by network elements with circular cross section, whereas more irregular pore shapes will be represented by triangular cross section, possibly with very sharp corners. Using square or triangular shaped network elements allows for the explicit modelling of wetting layers if non-wetting phase occupies the center of the element and wetting phase remains in the corner. A constant clay volume is assigned to each pore and throat to represent regions of the pore space that cannot be invaded by oil.

Initially all the elements are completely full of water. This situation is defined by assigning an initial contact angle of zero to all pores and throats. During primary drainage, displacement only occurs through piston-like displacement, where an
oil-filled element can fill a neighboring water-filled element once the entry capillary pressure is exceeded. The elements are filled in order of increasing capillary entry pressure (assuming they have an oil-filled neighbor). This process continues until some predefined saturation is reached or all elements have been filled by oil. Once a polygonal element has been filled by oil, water still remains in the corners. As mentioned before, it is assumed that flow is capillary dominated, and that viscous and gravitational effects are negligible at the pore scale. After primary drainage, the part of the rock in direct contact with oil will have its wettability altered, whereas the corners and water-filled elements remain strongly water-wet. With wettability alteration and water in corners, the mechanisms by which water can displace oil become more complex. The three main processes are piston-like displacement, pore body filling and snap off. Injection is complete when a target capillary pressure or saturation has been reached, or when all available pores and throats have been invaded by water. When water invades an oil-wet pore, a layer of oil may form sandwiched between water in the center and water in the corners. These oil layers maintain the connectivity of the oil phase and allow low residual oil saturations to be reached.

3.2.1. Computing relative permeability using network modelling

To calculate relative permeabilities, the following assumptions are made: a) the fluid flow in each phase is independent of other phase; b) the flow is incompressible and c) the pressure drop due to flow is negligible compared to capillary pressure. By imposing a pressure drop across the length of the model, the conservation of the mass at every pore \( i \) will be:

\[
\sum_j q_{p,ij} = 0
\]  

(3.1)

where \( j \) runs over all connected throats and \( q_p \) is the flow rate of each phase \( p \) between two pores \( i \) and \( j \). This equation can be solved for pressure everywhere to find the total flow rate. The flow rate \( q_p \) is given by:

\[
q_{p,ij} = \frac{g_{p,ij}}{L_{ij}} (P_{p,i} - P_{p,j})
\]  

(3.2)

where \( g_p \) is the fluid conductance, \( L \) is the length between the pore centres and \( P_p \) is the phase pressure. Eqs. 3.1 and 3.2 can be solved in term of pore pressures. With
the pressures known at either side of any cross sectional plane within the network model, the total flow rate can be computed from Eq. 3.2. The relative permeability of each phase is then given by:

$$k_{rp} = \frac{q_{lmp}}{q_{isp}}$$  \hspace{1cm} (3.3)

where \(q_{lmp}\) and \(q_{isp}\) are the total flow rates in multiphase and single phase conditions respectively.

3.3. Analysis of mixed-wet data

The network model is used to match Zhou et al.'s experimental co-current water-flooding recoveries and wettability indices. Then the computed relative permeabilities and capillary pressures are used to simulate one-dimensional counter-current spontaneous imbibition to predict the observed experimental behaviour including the radically longer displacement times compared to water-wet media.

We use a network based on Berea sandstone and hence we have confidence that the network geometry is representative of the Berea cores used by Zhou et al. Moreover, we are able to predict accurately primary drainage and water-flood relative permeabilities for water-wet Berea. The prediction of mixed-wet data is more of a challenge since we need to distribute contact angles to each pore and throat. Contact angles are only adjusted in pores and throats filled with oil after primary drainage - water filled elements remain water-wet. In this work we assigned two contact angle distributions. The first distribution has values less than 105° and represents the water-wet or neutrally-wet regions of the rock. Such pores and throats are filled with oil after primary drainage, but undergo only a modest wettability alteration. The second distribution includes larger contact angles to represent the oil-wet regions. In this chapter we assumed that within each distribution, contact angle was distributed at random uniformly between some upper and lower bounds. In order to provide good connectivity of oil-wet and
water-wet regions, the oil-wet contact angles are distributed in clusters. A number of pores and throats are randomly selected. This pore or throat is assigned a contact angle from the oil-wet distribution, as are all its nearest neighbour connected pores or throats. Then all the nearest neighbors of these oil-wet elements are made oil-wet. The process continues until a target oil-wet volume fraction is reached. In this way, there will be patches of oil-wet pores and throats distributed among water-wet pores and throats. In all cases 50 clusters were used except for the aging time of 240 hours where number of clusters was 10 (Table 3.1). The network contains 12,349 pores and 26,146 throats. 50 clusters correspond approximately to a correlation length of 6 pores.

Zhou et al. used Eq. (1.15) as the wettability index. This definition is slightly different from the traditionally measured Amott wettability index but the results are the same. The samples in the imbibition and water-flooding tests with the same aging time had slightly different initial water saturations. In the network model we followed exactly the same sequence of saturation changes as observed in the experiments. To compute simulated imbibition and water-flooding recoveries and wettability indices using Eq. (1.15), and also to calculate the experimental saturations for the final imbibition and water-flooding recoveries, we use

\[
R_{imb} = \frac{S_w(P_e = 0) - S_{wi,imb}}{1 - S_{wi,imb}}
\]

(3.4)

\[
R_{wf} = \frac{S_w(r_w \geq 99) - S_{wi,wf}}{1 - S_{wi,wf}}
\]

(3.5)
3.3.1. Matching co-current water-flood recovery and wettability indices

The flooding sequence in the network model, given below, is identical to that followed in the Zhou et al.\textsuperscript{81} experiments. Note that we use co-current relative permeabilities to predict the behaviour of counter-current flow – several authors have suggested that this would lead to an over-estimate of imbibition rate\textsuperscript{18,69}.

1. Adjust the clay content to reach the lowest ever reached $S_{w}$, This will be the $S_{wc}$ of the sample. For Zhou et al.'s experiments\textsuperscript{81}, $S_{wc} = 15\%$.

2. Simulate primary drainage to $S_{wi}$ for each aging time.

3. Simulate wettability alteration by assigning the contact angle distributions.

4. Water-flood the sample until the water/oil ratio, $r_{wo}$ is 99.

5. Calculate the water-flood recovery using the Buckley-Leverett approach\textsuperscript{77} assuming no capillary pressure. Compute the wettability index and compare with experimental data. Repeat the procedure, adjusting the contact angle distributions in step 3 until the experimental and predicted recoveries and wettability indices match.

To match the water-flood recovery and wettability index five parameters were adjusted: the upper and lower bounds of the oil-wet and water-wet contact angle distributions and the oil-wet volume fraction. These parameters are shown in Table 3.1. The results of matching experimental co-current water-flooding recoveries and wettability indices are presented in Fig. 3.2 and Table 3.2.
Table 3.1. Contact angle distributions used in the network model to match experimental water-flooding recoveries and wettability indices shown in Table 3.2. The water-wet data is from a reference case that predicts water-wet relative permeabilities.

<table>
<thead>
<tr>
<th>Aging time</th>
<th>Initial Water saturation</th>
<th>Water-wet contact angle distribution (degrees)</th>
<th>Neutral and oil-wet contact angle distribution (degrees)</th>
</tr>
</thead>
<tbody>
<tr>
<td>hours</td>
<td>fraction</td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>Water-wet</td>
<td>.25</td>
<td>30</td>
<td>80</td>
</tr>
<tr>
<td>0</td>
<td>.155</td>
<td>50</td>
<td>92</td>
</tr>
<tr>
<td>4</td>
<td>.158</td>
<td>67</td>
<td>97</td>
</tr>
<tr>
<td>48</td>
<td>.162</td>
<td>74</td>
<td>98</td>
</tr>
<tr>
<td>72</td>
<td>.152</td>
<td>72</td>
<td>97</td>
</tr>
<tr>
<td>240</td>
<td>.157</td>
<td>79</td>
<td>102</td>
</tr>
</tbody>
</table>

Table 3.2. Network model results compared to Zhou et al. experimental imbibition and water-flooding absolute recoveries and wettability indices.

<table>
<thead>
<tr>
<th>Aging time</th>
<th>Imbibition $S_W$ at $Pc=0$</th>
<th>Water-flooding $S_W$ at $r_{wq}\geq99$</th>
<th>Wettability index</th>
</tr>
</thead>
<tbody>
<tr>
<td>hours</td>
<td>EXP</td>
<td>SIM</td>
<td>EXP</td>
</tr>
<tr>
<td>0</td>
<td>.414</td>
<td>.465</td>
<td>.507</td>
</tr>
<tr>
<td>4</td>
<td>.438</td>
<td>.426</td>
<td>.557</td>
</tr>
<tr>
<td>48</td>
<td>.405</td>
<td>.395</td>
<td>.648</td>
</tr>
<tr>
<td>72</td>
<td>.367</td>
<td>.370</td>
<td>.663</td>
</tr>
<tr>
<td>240</td>
<td>.254</td>
<td>.260</td>
<td>.687</td>
</tr>
</tbody>
</table>
Chapter 3

Fig. 3.2. Comparison of experimental water-flooding recovery for samples with different aging times, $t_a$ (after Zhou et al.\textsuperscript{81}) and predicted results using network model relative permeabilities. A good match to the data is achieved using plausible distributions of contact angles – see Table 3.1.

The ranges of contact angle are plausible – note that for water-flooding the water-wet regions are in fact weakly to neutrally-wet. As the aging time increases the oil-wet fraction increases, as do the contact angles in the oil-wet regions – this is physically consistent with the core overall becoming more oil-wet as it is aged for longer. The water-flood recoveries and wettability indices are accurately matched, which indicates that the model is able to capture the correct displacement physics with the right parameters. For zero aging time, the quality of water-flood and wettability index match is not as good as the others. It was not possible to match simultaneously water-flood recovery and the very low residual oil saturation for this case.
Strongly water-wet
Mixed-wet, $ta = 0$ hours
Mixed-wet, $ta = 4$ hours
Mixed-wet, $ta = 48$ hours
Mixed-wet, $ta = 72$ hours
Mixed-wet, $ta = 240$ hours

Fig. 3.3. Capillary pressure for different wettability states simulated by the network model. Strongly water-wet data from Jackson et al.\textsuperscript{41}

The capillary pressure and relative permeabilities calculated by the network model for all cases are presented in Figs. 3.3 and 3.4. Also shown are results for a water-wet reference case with initial water saturation of 25 percent that has already been shown to predict water-flood relative permeabilities accurately\textsuperscript{41}. As the aging time increases, the capillary pressure becomes lower and an increasing fraction of the curve lies below zero, indicating oil-wet properties. Recovery by spontaneous imbibition is governed by the regions of the capillary pressure curve above zero. Clearly the amount of oil recovered will decrease as the core becomes more oil-wet. The rate of recovery will be governed by the magnitude of the capillary pressure. While the capillary pressure is certainly lower than for a water-wet sample, it is typically less than an order of magnitude lower for the aged samples in the region where the capillary pressure is positive. This indicates that capillary pressure alone cannot explain the long imbibition times seen experimentally and that a theoretical interpretation of the results in terms of an effective contact angle, described earlier, is flawed.
Fig. 3.4. Relative permeability for different wettability states simulated by the network model to match Zhou et al.\textsuperscript{81} experimental water-flooding recoveries (Fig. 3.2), plotted on a linear scale (a) and on a logarithmic scale (b) Strongly water-wet data from Jackson et al.\textsuperscript{41}
As the aging time increases the capillary pressure decreases with more and more mobile water potentially displaced at a negative capillary pressure. The water relative permeability also decreases with aging time. This is a surprising result, since for a more oil-wet system, since water is the non-wetting phase, it will occupy the larger pores and throats increasing the relative permeability. However, for these mixed-wet media, water first invades small water-wet regions followed by oil-wet pores that are poorly connected. Hence $k_{rw}$ remains low until high saturations are reached and large water-filled elements span the system. This has been observed previously in network modeling studies by Valvatne and Blunt.\textsuperscript{73}

The relative permeabilities shown in Fig. 3.4 show that the residual oil saturations for the longest aging times are considerably lower than for a water-wet sample. This has been observed and explained by Salathiel\textsuperscript{67} – in the oil-wet regions oil layers maintain connectivity of the oil phase down to very low saturation that leads to higher end-point relative permeability. In water-wet systems, water already occupies fine pores and covers all the pore and throat surfaces, while oil exists in the middle of larger pores. After the start of water injection water easily invades all pore and throats and oil can be trapped in bypassed pores that leads to higher residual saturation and lower end-point water relative permeability.

The most remarkable feature of the relative permeability curves is that the water relative permeability for the aged samples is around two orders of magnitude lower than for a water-wet system at low and intermediate oil saturations (where the capillary pressure is positive) – Fig. 3.4. This phenomenon has already been observed using pore-scale modelling\textsuperscript{41,73}. During water-flooding in a mixed-wet system, water-wet pores and throats are preferentially filled first. However, if the oil-wet fraction is large, these pores and throats fail to make a connected path of filled elements across the network. This means that the water relative permeability is controlled by thin wetting layers in the corners of the pore space that have a very low conductance.

During forced displacement, the larger oil-wet pores are filled by water. This can lead to a rapid change in saturation, but until the water forms a connected pathway across the system, the water relative permeability remains very low. For
water-flood recovery the combination of a low water relative permeability and residual oil saturation leads to a high recovery as a function of pore volumes injected⁴¹ – the oil can escape readily from the system, while the low water relative permeability holds the water back. This can be seen in the predicted and experimental recovery curves – Fig. 3.2 – where water-flood recovery increases with increasing aging time. However, for spontaneous imbibition, this will lead to very slow recovery, as the recovery rate is governed by a combination of the capillary pressure and the water relative permeability. For the longer aging times, the capillary pressure is only positive for saturations close to \( S_w^i \) where the water relative permeability is very low. This is the physical origin of the very long imbibition times observed experimentally. We will test this hypothesis through simulation.

There are two possible explanations for the low recovery rates seen in imbibition experiments in mixed-wet systems. The first is that flow is slow due to the very low water relative permeabilities and capillary pressure. The second is that the capillary pressure is insufficient at the inlet to push out oil, while maintaining a finite value at the advancing water front. Our simulation results that we show later suggest that the first explanation is valid.

### 3.3.2. Prediction of experimental counter-current imbibition recovery

The relative permeabilities and capillary pressures derived from pore-scale modelling were used in a conventional simulation of counter-current imbibiton in one dimension (1D). The simulator used was Eclipse-100, which is an industry-standard reservoir simulator. In the 1D model, illustrated in Fig. 3.5, a reservoir of water was connected to a thin rectangular matrix slab (Table 3.3). All other faces not in contact with the fracture were closed (no flow boundaries). A total of 42 grid blocks was used in the simulation. This set-up is similar to that used to simulate imbibition in water-wet systems, Fig. 2.2. The grid used is shown in Fig. 3.5 – we performed grid refinement studies to ensure that we used sufficient grid blocks to obtain converged results. The same fluid properties as in the experiments were used (Table 3.3). The matrix porosity and absolute permeability calculated by the network model was used (Table 3.3). The whole system was at the same level;
therefore there was no hydraulic pressure difference (no gravity forces). No injection or production well was in the model and hence, no viscous forces were present. This means that the mechanism of recovery was imbibition as a result of capillary forces.

In Zhou et al.’s experiments, the cylindrical core samples had diameters and lengths in the range of 3.8 to 3.82 cm and 6.4 to 7.8 cm respectively. In the simulations the matrix block width and length was set to 4 and 8 cm respectively.

![Image of grid system](image)

**Fig. 3.5.** Grid system used for one-dimensional simulations of imbibition. A total of 42 grid blocks were used.

**Table 3.3.** Matrix, rock and fluid properties used in the simulations (after Zhou et al.\(^\text{81}\)).

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Porosity</td>
<td>fraction</td>
<td>0.207</td>
</tr>
<tr>
<td>Permeability(^*)</td>
<td>m(^2)</td>
<td>3.131(\times)10(^{-12})</td>
</tr>
<tr>
<td>Oil density</td>
<td>Kg.m(^{-3})</td>
<td>895</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>Pa.s</td>
<td>0.03925</td>
</tr>
<tr>
<td>Water density</td>
<td>Kg.m(^{-3})</td>
<td>1.012</td>
</tr>
<tr>
<td>Water viscosity</td>
<td>Pa.s</td>
<td>0.000967</td>
</tr>
<tr>
<td>Interfacial tension</td>
<td>N.m(^{-1})</td>
<td>0.0242</td>
</tr>
</tbody>
</table>

\(^*\) from network modelling
While for the water-flooding results the contact angles are varied to match the experiments, the comparison of imbibition recoveries shown in Fig. 3.6 are genuine predictions – no adjustment to the network model properties were made. Fig. 3.6 plots the results in terms of dimensionless recovery versus Ma et al.’s dimensionless time, Eq. (1.8). While the agreement between predictions and experiment is not perfect, we are able to reproduce the trend in recovery with aging time and demonstrate that for mixed-wet systems the imbibition times can indeed be orders of magnitude longer than for a water-wet system. The principal reason for long imbibition times is the very low water relative permeabilities observed in the mixed-wet sample and is not the consequence of very low capillary forces, although they are also low. In particular we find very low recovery at early times, as seen experimentally. We also accurately predict the absolute recovery that decreases with aging time – this is governed by the water saturation when the capillary pressure is zero – see Table 3.2.

Although we have found the time scale to correlate imbibition recovery in mixed-wet systems, it should be noted that at early times we over predict the imbibition recovery. The reason for this difference could be due to other mechanisms. One possibility is that this is the time needed for the establishment of a connected pathway of water through the wetting layers of the rock. Another possibility is that this is the time needed to overcome the capillary pressure at the outlet (bubble pressure).
Fig. 3.6. Simulation of experimental imbibition recovery for different aging times, $t_a$ (after Zhou et al.\textsuperscript{81}) using network model data (Fig. 3.4). Imbibition data from Zhou et al.\textsuperscript{81} experiments with initial water saturations of 20 % and 25 % are also included in the zero aging time data.
3.4. Discussion

The match to the water-flood data is not necessarily unique. Furthermore, a small difference in the contact angle range can lead to large changes in the prediction of imbibition recovery time. We used uniform distributions of two ranges of contact angles. These contact angle ranges and the number of pore clusters are five matching parameters that were used to match experimental data, namely the water and oil wettability indices, water-flooding recovery end point values and the shape of flooding recovery. However, it is likely that any other contact angle distributions that can simultaneously match water-flood recovery; wettability index and imbibition recovery should be very close to the distributions used here.

For the case of zero aging time, the experimental results show a water-wet behaviour as we see very little difference between water-flood and imbibition recoveries. For this case, all experimental data for zero aging time with different initial water saturations of 15 percent, 20 percent and 25 percent are plotted in Fig. 3.6 since the results are expected to be less sensitive to small changes of initial water saturation ($S_w$) for a water-wet system. For this case two sets of relative permeabilities were used in the imbibition predictions. The first set with an initial water saturation of 25 percent that already has been shown to match strongly water-wet data gives a good prediction of the zero aging time data. The second set comes from matching the zero aging time water-flood recovery and wettabilty index where the initial water saturation is 15 percent. Again the predictions are good. However, for both cases a discrepancy can be seen in the late time behaviour.

3.5. Scaling of counter-current imbibition in mixed-wet rocks

We have shown that the imbibition rate in mixed-wet media is controlled by the very low water mobility and that correlations based on an effective contact angle are unlikely to predict the behaviour. The Ma et al. dimensionless time, Eq. (1.8) ignores relative permeability effects and gives equal weight to the water and oil viscosities and thus may not be an appropriate scaling group for mixed-wet media. In contrast, Zhou et al. scaling group, Eq. (1.11) does account water and oil...
mobilities. To derive Eq. (1.11), they derived the following equation for Darcy velocity of water, \( u_w \), in counter-current imbibition:

\[
 u_w = \frac{\lambda_w \lambda_o}{\lambda_r} \frac{\partial P_c}{\partial x} \tag{3.6}
\]

where subscripts \( w \) and \( o \) stand for water and oil phases. Using the definition of mobility we can re-write Eq. (3.6) as:

\[
 u_w = \frac{k_{rw} k_m}{k_{rw} \mu_o + k_m \mu_w} \frac{\partial P_c}{\partial x} = \frac{k_{rw}}{(k_{rw} / k_m) \mu_o + \mu_w} \frac{\partial P_c}{\partial x} \tag{3.7}
\]

Analysis of imbibition in mixed-wet rocks in this chapter using pore-scale modelling revealed that water relative permeability is the crucial factor that influences the imbibition recovery speed. In mixed-wet rocks as the rock wettability tends toward oil-wet, the ratio of water to oil relative permeability approaches zero and hence:

\[
 u_w = \frac{\lambda_w \lambda_o}{\lambda_r} \frac{\partial P_c}{\partial x} \approx \frac{k_{rw} \partial P_c}{\mu_w \partial x} = \lambda_w \frac{\partial P_c}{\partial x} \tag{3.8}
\]

Based on Eq. (3.8), the following scaling law should be able to correlate imbibition recovery in mixed-wet rocks:

\[
 t_D = t \sqrt{\frac{K}{\phi L_c}} \frac{\sigma}{\lambda_w^*} \tag{3.9}
\]

In this equation, \( \lambda_w^* (= k_{rw} / \mu_w) \) is water mobility. If \( \lambda_{rw}^* \ll \lambda_o^* \) that means \( M^* \ll 1 \) Zhou et al. correlation, Eq. (1.11) will also reduce to Eq. (3.9). We suggest that rather than using the end-point water relative permeability (at the end of water-flooding) that increases with aging time (Fig. 3.4), we use the water relative permeability at the end of spontaneous imbibition (when \( P_c = 0 \)) that decreases with aging time.
3.5.1. Validity of the scaling functions for mixed-wet systems

To check the validity of the scaling functions of Ma et al.\textsuperscript{52}, Eq. (1.8), Zhou et al.\textsuperscript{80}, Eq. (1.11) and Eq. (3.9); a series of 1D-simulations for different oil to water viscosity ratios, $M$, were performed using the network model derived data for aging time of 72 hours. Our simulations cover a range of viscosity ratios, $M$, from 0.01 to 200. The recoveries from the simulations are plotted as function of different dimensionless time in Figs. 3.7 to 3.13.

For a given aging time, but different mobility ratios, $M$, all the recoveries lie on the same universal curve using our scaling group, Eq. (3.9) as the dimensionless time, Fig. 3.7. While there is some scatter in the data, the simulation results for different aging times (different wettability states) also, approximately, fall on the same curve, Fig. 3.8. This demonstrates that it is the water mobility that controls the imbibition rate. The water relative permeability is around four orders of magnitude lower than the oil relative permeability in the saturation range where imbibition occurs, Fig. 3.4. In order for the oil mobility to affect the imbibition rate significantly, the viscosity ratio, $M$, would need to be around 10,000 or greater.

The same analysis using Zhou et al.\textsuperscript{80} relation, Eq. (1.11) gives identical results, since $M^* \ll 1$ as long as the relative permeabilities at the end of imbibition are used, Fig. 3.9. In contrast, using Ma et al.\textsuperscript{52} relation, Eq. (1.8) gives poor results, with a wide scatter in the recoveries for different mobility ratios, $M$, Fig. 3.10. This result does not agree with Tong et al.'s\textsuperscript{72} conclusion from their imbibition experiments that imbibition recovery at mixed wettability for different viscosity ratios can be correlated satisfactory by the square root of the geometric mean of the water and oil viscosity.

Two other dimensionless groups were also tested, Figs. 3.11 and 3.12. Using either oil viscosity or square root of oil and water mobility gives poor scaling results.

The results of this study shows that for mixed-wet systems the time-scale for imbibition is inversely proportional to the water mobility and insensitive to the oil mobility. This result is different from that found in water-wet systems.
Fig. 3.7. Our scaling relation, Eq. (3.9) is used to correlate imbibition data for a wide range of viscosity ratios, $M$. Using water mobility causes all the results to fall on a single universal curve.

Fig. 3.8. Our scaling relation, Eq. (3.9) is used to correlate imbibition data for different wettability states. Using water mobility is sufficient to correlate imbibition data.
Fig. 3.9. Imbibition data in Berea sandstone are correlated using Zhou et al.\textsuperscript{80} relation, Eq. (1.11) with water mobility defined at the end of spontaneous imbibition. The reported imbibition data in Diatomite by Zhou et al.\textsuperscript{80} give similar results although the nature of the cores are different.

Fig. 3.10. Using geometric mean of viscosities is not sufficient to correlate imbibition data for different viscosity ratios, $M$. 

\[ t_D = t \left( \frac{K}{\phi} \right)^{1/2} \left( \frac{1}{\sqrt{M} + 1/\sqrt{M}} \right) \]

\[ t_D = t \left( \frac{K}{\phi} \right)^{1/2} \left( \frac{1}{\sqrt{\mu_o \mu_w}} \right) \]
Fig. 3.11. Imbibition recoveries in mixed-wet rock for different viscosity ratios, $M$, cannot be scaled using oil mobility.

Fig. 3.12. Imbibition recoveries in mixed-wet rock for different viscosity ratios, $M$, cannot be scaled using oil and water mobilities where this equation was able to correlate water-wet, Fig. B.9.
So far this analysis has been limited to direct comparison with mixed-wet experimental data for one value of initial water saturation, $S_{wi}$. We used our scaling group, Eq. (3.9) to correlate the result of simulation of one dimensional (1D) counter-current imbibition in the grid system, Fig. 3.5, using mixed-wet relative permeability and capillary pressure of an Iranian carbonate fractured oil reservoir with different initial water saturations (that will be used in the reservoir study in chapter 4). The correlated data, Fig. 3.13, are qualitatively reasonable. However, the effect of initial water saturation needs more investigation. Zhou et al. studied systems with other values of $S_{wi}$ that could be analyzed using the same approach.

A similar study was done to find a dimensionless group to scale imbibition recovery in both water-wet and mixed-wet systems. The result of this study is presented in Appendix-D of this chapter. Two correlations, Figs. D.10 and D.12 give good results although the expressions require further testing and need a fundamental physical justification.

Fig. 3.13. Our scaling relation, Eq. (3.9) is used to correlate imbibition recovery simulation of mixed-wet properties of an active Iranian carbonate fractured reservoir.
3.5.2. **Empirical correlation fit to experimental data**

Many authors have matched imbibition data in water-wet systems with an exponential recovery, Eq. (1.9) with time\(^6.47,52\). The best match to our simulation results is given using \(t_D\) from either Eq. (3.9) or (1.11) and dimensionless rate constant, \(\lambda = 0.2\), Fig. 3.14:

\[
R = R_{\text{init}}(1 - e^{-0.2t_D})
\]  

(3.10)

The correlation under-predicts recovery at early time. However, note that our simulations over-predict recovery at early time, Fig. 3.6, and so the correlation may be a better match to experiment. The dimensionless rate constant, \(\lambda\), is higher than used to match water-wet data using Ma et al.\(^52\) dimensionless time, Eq. (1.8) \((\lambda = 0.05\)\(^52\)) despite the much longer real imbibition times. The reason for this is that Eq. (1.8) does not account for the water relative permeability that is typically very low.

![Figure 3.14](image-url)

**Fig. 3.14.** Comparison of simulated recoveries as a function of dimensionless time, Eq. (3.9) and an empirical correlation given by Eq. (3.10). The simulations are for an aging time of 72 hours and various ratios, Fig. 3.7. The correlation is only an approximate prediction of the recovery.
An analytic expression for the imbibition recovery in mixed-wet media, Eq. (3.10), can be used to derive a transfer function for field-scale dual porosity simulation of flow in fractured reservoirs (see chapter 2). This work suggests that the water mobility is the key factor controlling imbibition rate in mixed-wet systems. Eq. (3.10) is a simple one-parameter empirical match to recovery – we did not attempt to use other expressions that better represent water-wet data.

In our analysis we neglected the effect of gravity. It was discussed (sec. 4.4, ch.1) that Xie and Morrow mentioned that in mixed-wet media it is likely gravitational effects also impact recovery, in which case a dimensional time should include buoyancy effects (such as Eq. (1.19)). Using Xie and Morrow approach and considering Eq. (3.9), we can write:

$$t_D = t' \left[ \frac{K}{\phi \frac{\sigma_a}{L_c}} \lambda_w + \frac{K}{\phi} \frac{\Delta \rho \cdot g}{L_H \mu_w} \right]$$  

(3.11)

This equation needs to be tested and validated.

### 3.6. Conclusions

We have used pore-scale network modelling to study water-flooding and counter-current imbibition in mixed-wet Berea. We adjusted the contact angles in the network model to match experimental water-flood recovery and wettability index for samples aged in crude oil for different times. As the aging time increased, the samples became more oil-wet. We were able to simulate the results using plausible ranges of contact angles. We then used the computed relative permeabilities and capillary pressures in a conventional simulator to predict recovery from counter-current imbibition with no further adjustment of any parameters. We were able to predict the orders-of-magnitude increase in imbibition time over water-wet media seen in mixed-wet samples. In a mixed-wet system spontaneous imbibition is limited to a narrow saturation range where the water saturation is small. The water is poorly connected through the network in wetting layers and the water relative permeability is extremely low, leading to recovery rates at least a thousand times slower than for water-wet media. We
suggest that water mobility is the key parameter controlling imbibition rate in mixed-wet rocks. This study indicates that a conventional treatment of the problem of counter-current imbibition using physically-based relative permeabilities and capillary pressures is sufficient to predict recovery and the apparent slow start to imbibition. However, in some cases the quantitative match to experiment was poor, indicating that we had not properly represented the pore-level distribution of wettability.

All the imbibition recovery curves fell on approximately a universal curve if plotted as a function of a dimensionless time, Eq. (3.9), that was proportional to the water mobility at the end of imbibition. We proposed a correlation to match the simulation results, Eq. (3.10), that could be used to predict imbibition rates for mixed-wet media with a variety of viscosity ratios.
3.7. Appendix-D

Study of validity of various scaling groups to scale water-wet and mixed-wet imbibition data

The dimensionless groups shown in Table D.1 were also derived and tested to scale simultaneously the imbibition recovery in water-wet and mixed-wet media. The main purpose was to find a correlation that can be used to scale both water-wet and mixed-wet imbibition recovery data to be used to derive a transfer function for field-scale simulation. The analysis in chapter 2 showed that water-wet recoveries are best correlated with the geometric mean of oil and water viscosities. However, the analysis of chapter 3 revealed that using geometric mean of oil and water viscosity gives poor scaling over a wide range of viscosity ratios, $M$, and mixed-wet data are best correlated using only the water mobility. The correlated water-wet and mixed-wet data can be made to fall on a universal curve for each case but these curves are far from each other. To present a universal curve for water-wet and mixed-wet imbibition recovery correlations, these two curves should match each other. For this purpose, different important factors that could affect the recovery were used in different dimensionless groups. In some cases, the water-wet curve and mixed-wet curves are very close or even match. These equations need further investigation and testing.

The results of imbibition predictions (sec. 2.4, ch. 2) using pore-scale data$^{41}$ for different viscosity ratios, $M$, and the simulation of Bourbiuax and Kaladjian$^{18}$ experiments (sec. 2.2, ch.2) were used as water-wet media. In all water-wet cases, relative permeabilities are an end point that is oil relative permeability at initial water saturation, $S_{wi}$, and water relative permeability at residual oil saturation, $S_{or}$, except in the equation presented in Fig. D.12. In this equation, oil relative permeability needs a specific definition.
The predictions of spontaneous imbibition of different aging times (different wettability states) from Zhou et al.'s experiments (sec. 3.3.2, ch. 3) were used for mixed-wet data. In all cases, relative permeabilities are imbibition end points, that is oil relative permeability at initial water saturation, \( S_{wi} \) and water relative permeability at the oil saturation, \( S_{or} \) at the end of spontaneous imbibition \( (P_c=0) \).

In this study the effect of different initial water saturations, \( S_{wi} \) was included. Also the effect of different final recoveries and recovery factors were studied by including residual oil saturation, \( S_{or} \) and \( (1 - S_{or}) \). To consider the effect of capillary pressure, a dimensionless \( J \) value is also included in some dimensionless groups.

This study showed the influence of each parameter on the scaling of the recoveries and possibility of presenting a general scaling group for imbibition recovery in water-wet and mixed-wet rocks.

Two correlations, Figs. D.10 and D.12 give good results, although the expressions require further testing. Furthermore, a fundamental physical justification of the results is missing. Lastly the two correlations use a geometric average of viscosity - for mixed-wet data this will not correlate recoveries if the oil to water viscosity ratio, \( M \), varies-see Fig. 3.10.
Table D.1. List of the tested dimensionless groups and the figures that illustrate the results.

<table>
<thead>
<tr>
<th>Dimensionless group</th>
<th>Figure</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \sqrt{\lambda_w^2 + \lambda_r^2}$</td>
<td>Fig. D.1</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{k_{rw}}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.2</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} S_w i \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.3</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.4</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.5</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.6</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.7</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \frac{1}{S_w i (1 - S_o r)} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.8</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \frac{1}{S_w i (1 - S_o r)} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.9</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \frac{1}{S_w i (1 - S_o r)} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.10</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{1}{L_c^2} \frac{1}{S_w i (1 - S_o r)} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.11</td>
</tr>
<tr>
<td>$t_D = t \frac{K \sigma}{\phi} \frac{k_r}{L_c^2} \sqrt{\mu_w \mu_o}$</td>
<td>Fig. D.12</td>
</tr>
</tbody>
</table>
Fig. D.1. Imbibition recoveries in mixed-wet rock for different aging times, $t_{a}$, cannot be scaled using oil and water mobilities whereas water-wet recoveries were successfully correlated for different viscosity ratios, $M$.

Fig. D.2. Imbibition recoveries in mixed-wet rock for different aging times, $t_{a}$, and in water-wet rock for different viscosity ratios, $M$ can be scaled using oil and water viscosities but the correlated data does not overlap.
Fig. D.3. Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, were scaled by including initial water saturation in the dimensionless group but the correlated data does not overlap.

Fig. D.4. Including square root of water relative permeability in the dimensionless group can be used to scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other.
Fig. D.5. Imbibition recoveries in mixed-wet rock for different aging times, $t_0$, and in water-wet rock for different viscosity ratios, $M$, were scaled by including initial water saturation and water relative permeability in the dimensionless group but the correlated data does not overlap.

Fig. D.6. Including initial water saturation and square root of water relative permeability in the dimensionless group can be used to scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_0$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other.
Fig. D.7. Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, were scaled by including initial water saturation, water relative permeability and residual oil saturation in the dimensionless group but the correlated data does not overlap.

$$t_D = t \frac{K \sigma \frac{S_w}{k_{rw}}}{\phi \frac{J_c}{S_{wi}} \frac{1}{\sqrt{\mu_w \mu_o}}}$$

Ma et al Express., Eq. (1.10)
Mixed-wet data, $t_a = 0-240$ hours
Bourbiaux & Kalaydjian data
Water-wet data, $M=0.01-200$

Fig. D.8. Adding the $J$ value computed at initial water saturation to the dimensionless group shown in Fig. D.7 can scale imbibition recoveries in water-wet rock for different viscosity ratios, $M$, but recoveries in mixed-wet rock for different aging times, $t_a$, cannot be scaled although water-wet and mixed-wet curves are getting close to each other. The correct value of $P_c$ at $S_{wi}$ to calculate the $J$ value is the challenging part of this equation.

$$t_D = t \frac{K \sigma \frac{1}{S_w} k_{rw}}{\phi \frac{J(S_{wi})}{L_c} \frac{L_c^2}{S_{wi}} \frac{1}{\sqrt{\mu_w \mu_o}}}$$

Ma et al Express., Eq. (1.10)
Mixed-wet data, $t_a = 0-240$ hours
Bourbiaux & Kalaydjian data
Water-wet data, $M=0.01-200$
Fig. D.9. Including \((I-S_{or})\) in the dimensionless group shown in Fig. D.8 can scale imbibition recoveries in water-wet rock for different viscosity ratios, \(M\), and mixed-wet rock for different aging times, \(t_a\), although Bourbiaux & Kalaydjian data show a discrepancy. The correct value of \(P_c\) at \(S_{wi}\) to calculate \(J\) value is the challenging point of this equation.

Fig. D.10. All imbibition recoveries in mixed-wet rock for different aging times, \(t_a\), and in water-wet rock for different viscosity ratios, \(M\) and Bourbiux & Kalaydjian water-wet data fall on a universal curve by the dimensionless group shown. There is little physical justification for the terms used although it gives a good result. Finding the correct value of \(P_c\) at \(S_{wi}\) is the challenging point of this equation.
Fig. D.11. Imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$, were scaled but the correlated data does not overlap.

Fig. D.12. All imbibition recoveries in mixed-wet rock for different aging times, $t_a$, and in water-wet rock for different viscosity ratios, $M$ and Bourbiaux & Kalaydjian water-wet data fall on a universal curve by the dimensionless group shown. In mixed-wet rocks, $k_r$ is the water relative permeability at the end of imbibition. However, in water-wet rocks, $k_r$ is defined as the end-point oil relative permeability.
Chapter 4: Analysis of the Impact of Wettability at the Field-Scale

Summary

In this chapter the impact of rock wettability on field behaviour is tested. Different relative permeability and capillary pressures representative of different wettability states were used in a dual porosity simulation. These data were applied to a major Iranian fractured oil reservoir.

4.1. Field description

Karanj is one of the major Iranian fields located in the South-West of Iran, Fig. 4.1. The field data are confidential. Therefore disclosure of the data is restricted. In particular all real production data or details of the reservoir model are not shown. The length and width of this field on the crestal axis is about 30 km and 6 km respectively. The Asmari limestone formation (Oligo-Miocene) is the main pay formation of the field with a true thickness of nearly 700 meters. The porosity and average water saturation of the reservoir rock are approximately 11 percent and 25 percent respectively where rock absolute permeability is in the range of 0.5-1.5 md. The reservoir has light oil (36 °API) with a high formation volume factor of 1.5 at the bubble point pressure of 220 bar absolute. The difference in oil and water gradients ($\Delta \rho_{o-w}$) is 2.7 kPa/m.

The reservoir was initially undersaturated. The reservoir crest is at 1100 metre subsea (mss). The fracture network is extended through the reservoir. The original fracture water-oil contact was at 2800 mss which means that the original reservoir oil column was about 1700 m high. The initial uniform reservoir oil pressure at oil datum (2300 mss) was 320 bar. The estimated original oil in place of the reservoir is about 1.5 billion m$^3$. 

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H. Sh. Behbahani
Oil production started in November 1964. So far 14 producing and 7 observation wells have been drilled, Fig 4.2. Maximum field rate has been near to 42,000 cubic metres per day (m³/day), Fig 4.9. The average field production rate in the last 5 years is 32,000 m³/day. Cumulative field oil production has been near to 270 million m³ at the end of year 2000. This represents an overall recovery of only 18 percent. The reservoir oil pressure was dropped 120 bar due to the production and the water-oil contact in the fracture network has risen nearly 120 m, Figs. 4.10 to 4.12. After nearly 6 years from the start of oil production, the reservoir pressure at the crest reached the bubble point and a gas cap appeared at the crest, Fig. 4.12. Due to the high oil formation volume factor of the reservoir oil, a pressure maintenance crestal gas injection was planned for the field. Gas injection started in mid 1992 via gas injection wells. The average gas injection rate has been about 5 million m³/day, Fig. 4.9. The gas-oil contact was fallen about 1000 metres due to oil production and gas injection. This means that the oil column has shrunk to nearly 580 m, Fig. 4.12.
Fig. 4.2. Reservoir contour map on top of the Asmari formation that shows the entry point of the wells into the formation.

4.2. Impact of wettability on the field behaviour

Eclipse-100 was used to simulate the Karanj reservoir for different wettability states. The dual porosity feature of the model was applied in all cases. In this approach, the fracture network is the main system of flow and matrix blocks acts as the source or sink to the fracture flow system. The flow in fractures is modeled using the three dimensional form of Eq. (2.2) and transfer between the fracture network and matrix blocks is modeled using Eq. (2.3) that is the conventional form of the dual porosity transfer functions. The model does not use the experimentally based transfer function that we derived in chapters 2 and 3. The comparison of these transfer functions gave different results (Sec. 2.5.5). However, we will use the relative permeabilities and capillary pressures found in chapters 2 and 3 to represent different matrix wettabilities. It should be noted that we did not undergo a complete reservoir simulation study including adjusting the reservoir model to match the production history.
4.2.1. Analysis of the model

4.2.1.1. Field data

Four sets of PVT data for a temperature range of 60 °C to 90 °C are available for this field. These data come from laboratory tests on reservoir samples taken at different depths. Oil bubble point pressures in these data are 217 to 240 bar absolute that shows a vertical gradient of composition in the reservoir due to the temperature gradient. Oil viscosity at the bubble point pressures varies from 0.41 to 0.47 mPa.s. To include the effect of change of gas-oil interfacial tension with pressure, a table of different surface tensions versus pressure was included. These data come from laboratory tests on samples from another Iranian fractured reservoir that has similar fluid properties.

There are five rock types in the reservoir with different initial water saturation, $S_{wi}$. The relative permeability and capillary pressures for two of them are presented in Figs. 4.3 and 4.4. These data are the result of core studies performed in 1978.

Fig. 4.3. Imbibition relative permeability and capillary pressure for field rock data with $S_{wi}=0.15$. 
Chapter: 4

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Chapter 4

Capillary Pressure

Relative Permeability

Fig. 4.4. Imbibition relative permeability and capillary pressure for field rock data with $S_{w} = 0.435$.

The field capillary pressure and relative permeabilities are indicative of a mixed-wet or oil-wet system. However, wettability indices for this field were not measured. The oil residual saturation, $S_{or}$, varies from 0.22 to 0.32. This will lead to different final recoveries from each rock type. The rocks with higher residual saturation also have higher $S_{wi}$ that will result in poor recovery from these rock types. On the other hand, relatively higher oil relative permeability can lead to higher recovery rate from these rocks.

The gas-oil relative permeability and capillary pressures that were used for all cases are illustrated in Figs. 4.5 and 4.6. These data show an oil-wet characteristic.

The fracture relative permeabilities were assumed to be equal to the saturation of each phase and the fracture capillary pressure was set to zero. The permeability of the fractures varied between 1000 and 2500 md. The fracture volume in the fractured reservoirs is very low. Here the fractured porosity assumed to be between 0.00075 and 0.003.
Fig. 4.5. Gas-oil capillary pressure for three field rock types.

Fig. 4.6. Gas-oil relative permeability of three field rock types.
The aquifer in Karanj field is active. This allowed the water-oil contact to rise after the start of oil production as the reservoir oil pressure dropped. The aquifer properties were matching parameters to reproduce the production history.

4.2.1.2. Different wettability data

We also simulated field production using mixed-wet data provided in chapters 2 and 3. For this exploratory study we assume that multiphase flow properties used to reproduce the behaviour in high permeability sandstone can be used to represent a low permeability carbonate reservoir. The shape of relative permeability and capillary pressure is influenced by the pore size and contact angle distributions. Low permeability carbonate rocks normally have a non-homogenous nature with many of fine pores and throats that leads to higher irreducible water saturation and threshold pressures than most sandstones. Sandstone rocks are normally more homogenous with higher permeability that leads to lower connate water saturations. Although we scaled the capillary pressure computed in a sandstone rock based on the rock permeability contrast, we assumed that the shape of capillary pressure does not change.

To change the wettability of reservoir rock, different relative permeabilities and capillary pressures were used. For the water-wet case, the relative permeabilities from the simulation of Zhou et al.'s experiments for an aging time of zero was used whereas for the mixed-wet case the data for an aging time of 72 hours was selected (Fig 3.4, ch. 3). A set of data presented by Jackson et al. was used to represent strongly water-wet rock (Fig 3.4, ch. 3). These data have already been shown to match experimental water-wet data in Berea sandstone, Fig. 3.6. The relative permeabilities are illustrated in Fig. 4.7.

The reservoir matrix absolute permeability is in the range of 0.5 to 1.5 md whereas the absolute permeability of the network data is more than 3 Darcy. In order to produce a situation similar to the reservoir the network matrix capillary pressure data were scaled based on the absolute permeability ratio. The capillary pressures kept their original functional form (Fig. 3.3, Ch. 3) but were increased by the square root of the ratio of the network absolute permeability to the reservoir matrix
absolute permeability. This is standard Leverett $J$ function scaling\textsuperscript{15}. By this scaling, the capillary pressures were increased to be approximately 100 times larger than the field data for the strongly water-wet case. Therefore it is expected that the capillary forces play a great role in recovery in these cases. The capillary pressure data that were used in the simulations are presented in Fig. 4.8.

![Fig. 4.7. Relative permeabilities of different wettability states data used to test the impact of wettability.](image1)

![Fig. 4.8. Scaled capillary pressure of different wettability states data used to test the impact of wettability.](image2)
For water-wet and mixed-wet cases, $S_{wi}$ is 0.15 whereas for the strongly water-wet case, $S_{wi}$ is 0.25 for all rock types. The $S_{wi}$ of the field rock types are in the range of 0.15 to 0.435. This situation will result in different original oil in place. Original oil in place for the field data and for the strongly water-wet data are close to 1.5 billion m$^3$ whereas the original oil in place for the mixed-wet and water-wet cases are close to 1.65 billion m$^3$ that is about 10 percent higher than the other cases. This point was considered in our analysis. It should be noted that the mixed-wet system has the lowest residual saturation, $S_{or} (=0.07)$ and the lowest $S_{wi} (=0.15)$.

The field gas-oil relative permeability and capillary pressures, Figs. 4.5 and 4.6 were also used for these cases based on the similarity of the $S_{wi}$.

4.2.1.3. Model description

The black oil model was used. Three phases of gas, oil and water were present in the model. A Cartesian grid system was used. 17640 fracture and matrix grid blocks were defined in the model. The number of grid blocks in x, y and z directions was 21, 15 and 28 respectively. The matrix block height in the model varied between 3 and 8 meters; therefore the number of matrix blocks vertically in each simulation grid blocks will be between 6 and 16. The fracture spacing in x and y directions in the model was determined implicitly as only the block heights and shape factors are input parameters. The shape factors are in the range of .1 to .7 m$^{-2}$ that corresponds to 4 to 11 meter cubic blocks. This means the range of matrix block dimensions in x and y directions are near to the block heights (3-8 m). Therefore the number of matrix blocks in each simulation grid blocks (1.4 km ×0.4 km in x and y directions) is very large. A similar oil production and injection rate, Fig. 4.9 was used in all cases.
Fig. 4.9. History of oil production and injection. This data is the same for all cases. Essentially oil production is fixed as a boundary condition.

4.2.2. Results

The effect of different data sets on reservoir behaviour in terms of different parameters was evaluated. The change in the history of gas-oil and water-oil contact depth, the percent of oil produced due to water displacement, oil expansion and gas influx were the parameters studied. The efficiency of water displacement in various wettability states was analyzed using these parameters. The comparisons are illustrated in Figs. 4.11 to 4.15. These figures clearly show the sensitivity of reservoir behaviour to rock wettability.

Fig. 4.10. Reservoir oil pressure predictions for different wettability states.
The pressure history, Fig. 4.10 shows some differences at late time between different cases. However, due to the similar rate of production and injection these differences are not significant.

This field was originally undersaturated. The oil production rate was very low for a period from 1978 to 1992. Gas injection was started in mid 1992. This change in production plan lead to improved recovery.

In view of the analysis of imbibition in water-wet and mixed-wet systems presented in the previous chapters, it was expected that recovery to be higher in the water-wet systems and lower for the mixed-wet and field rocks that give very little recovery by imbibition. The analysis of oil-water contact level movements, Fig. 4.11 shows similar trend. The two water-wet cases data give higher recovery compared to mixed-wet and field data as the water-oil level is lower for those data. Since oil production is the same in all cases the amount of water table movement indicates how efficient the displacement is. A smaller amount of change in the water level indicates an efficient process and higher ultimate recovery. Although the mixed-wet data has the lowest $S_{wl}$ and $S_{or}$ its recovery is lower. If viscous and gravity forces played a significant role in determining overall recovery, the recovery from the water invaded zone should be similar to that obtained from water-flooding or forced displacement resulting in a higher recovery for mixed-wet data.

Fig. 4.11. The rise of the water-oil contact level is strongly affected by the wettability of reservoir the rock.
This shows that gravitational and viscous forces were insufficient to allow a significant amount of forced displacement in this case. Using larger scaled capillary pressures to represent low permeability carbonate rock would lead to lower recoveries. The density contrast over an extremely high oil column was insufficient to overcome capillary forces. For instance, the pressure difference due to buoyancy in 100 m of the oil column is approximately $2.7 \times 10^5$ Pa – from Fig. 4.8 this is insufficient pressure to affect recovery significantly even for a large change in oil-water level. The capillary pressure for the field rock data is also large, Figs. 4.3 and 4.4 and gravitational forces were insufficient to allow a significant amount of forced displacement. Field data give less oil in place compared to mixed-wet system but the capillary pressure of the mixed-wet data is much larger. Hence field data gives an overall oil-water contact movement similar to the mixed-wet system.

Fig. 4.12. Fracture gas-oil and water-oil contact levels movement for different wettability states.
After 1980 when the rate of rise of oil-water contact was decreased due to gas injection, the effect of viscous forces was also reduced in the water invaded zone compared to the former period and capillary forces played the major role. The degree of imbibition explains the clear difference between oil-water level for the two water-wet cases compared to the mixed-wet and field data.

At late times – after 1980 – the majority of oil recovery comes from gas cap expansion, Fig. 4.15. Hence the rate of rise of the oil-water contact decreases in all cases and the recoveries are similar since now it is controlled by the gas/oil properties that are the same in all cases.

Fig. 4.13. The fraction of total oil produced by water displacement for different wettability states.
Fig. 4.14. The fraction of total oil produced by oil expansion for different wettability states.

Fig. 4.15. The fraction of total oil produced by gas influx for different wettability states.
4.3. Conclusions

We have presented a field-scale analysis of displacement in an Iranian fractured reservoir. We showed that wettability has a significant impact on recovery. In this study, capillary effects played a major role in the displacement. By using rather high capillary pressures the aquifer drive allowed capillary imbibition with the best recovery from the water invaded zone for water-wet systems although the mixed-wet data has the lowest $S_{wi}$ and $S_{or}$. This example illustrates that at the field scale a subtle interaction between capillary, gravitational and viscous forces controls recovery. This underlines how uncertain our present modelling of fractured reservoirs is and emphasises the importance of an accurate characterisation of wettability and multiphase flow properties.
Chapter 5: Conclusions and Future Work

5.1. Conclusions

In this thesis counter-current imbibition, a key recovery mechanism in oil reservoirs, was studied with the aim of improving the modelling of oil recovery from water-wet and mixed-wet fractured reservoirs using transfer functions based on experimental results in the literature.

5.1.1. Original targets

Answer to the following questions was required:

1. Can counter-current imbibition be explained using a conventional Darcy formulation for the flow equations?

2. Can a semi-empirical dimensionless time correlate all spontaneous imbibition recoveries in water-wet rocks? Can the semi-empirical equation be used to simplify the simulation of complex multi-dimensional imbibition?

3. How can the induction time at the start of spontaneous imbibition in mixed-wet rocks be explained? What is the key factor that controls imbibition recovery in mixed-wet rock? Can an appropriate set of relative permeabilities and capillary pressure reproduce the induction time?

4. Is it possible to suggest a scaling law for spontaneous imbibition in mixed-wet rocks that can correlate imbibition recovery for different wettability states and for various mobility ratios?
5.1.2. Our results

1. It was shown that a conventional Darcy treatment of multiphase flow is adequate to describe counter-current imbibition if appropriate relative permeabilities and capillary pressures are used. The results suggest that an approach describing multiphase flow with rate dependent coefficients although intriguing, is not necessary to predict the experiments.12

2. The different formulations for dimensionless times proposed in the literature were tested and showed that the time scale for recovery is inversely proportional to the geometric mean of the water and oil viscosities for water-wet media when the oil to water viscosity ratio is finite.

3. A transfer function, Eq. (2.9) was derived that matched core-scale imbibition experiments to be used in large-scale simulation. It was demonstrated that with an appropriate choice of this transfer function the behaviour of the two-dimensional (2D) displacement can be adequately reproduced using a one-dimensional (1D) model.

4. Quasi-static pore-scale network modelling as a novel tool was used to study the physics of imbibition in mixed-wet rocks. It was possible to reproduce the observed dramatic increase in imbibition time as the system changes from being water-wet to mixed-wet.

5. The study indicates that a conventional treatment of the problem of counter-current imbibition in mixed-wet systems using physically-based relative permeabilities and capillary pressures is sufficient to predict recovery and the apparent slow start to imbibition. The low imbibition rate is due to very small water relative permeabilities.

6. It was suggested that water mobility is the key parameter controlling imbibition rate in mixed-wet rocks. By including the water mobility in the dimensionless time, an analytically supported scaling group, Eq. (3.9) was
presented that is simple and physically meaningful and allows successful correlation of experimental spontaneous imbibition recoveries for different wettability states and for a wide range of viscosity ratios.

7. A correlation, Eq. (3.10) is proposed to match the simulation results that could be used to predict imbibition rates for mixed-wet media with a variety of viscosity ratios.

8. Two correlations were found that could match imbibition recovery in both water-wet and mixed-wet systems although these equations require further theoretical justification.

9. The impact and application of the study at the field scale was investigated. A field-scale analysis of displacement in an Iranian fractured reservoir was presented and it was showed that wettability has a significant impact on recovery. This example illustrated that at the field scale a subtle interaction between capillary, gravitational and viscous forces controls recovery. This underlines how uncertain our present modelling of fractured reservoirs is and emphasises the importance of an accurate characterisation of wettability and multiphase flow properties.

5.2. Future work

1. This study showed that the recovery characteristics of mixed-wet rocks are very complex. Initial water saturation is a very important factor. Zhou et al.\textsuperscript{81} presented a series of water-flooding and imbibition recoveries in Berea samples with 20 and 25 percent initial water saturations. The same approach can be used to analyse these results to test the proposed scaling group, Eq. (3.9) for experiments with different initial water saturation. The aim would be to develop a scaling group to correlate imbibition recoveries in mixed-wet media with various initial water saturations for different wettability states and for a wide range of viscosity ratios.
2. An empirical correlation to predict imbibition recovery in mixed-wet media was presented, Eq. (3.10). This correlation can be used to derive a transfer function and placed in a dual porosity model to simulate imbibition recovery at the field scale.

3. The effect of gravity was neglected in this analysis. An equation was suggested, Eq. (3.11) to include gravity. This equation could be tested and evaluated.

4. An attempt was made to develop a scaling equation that can correlate imbibition recovery in both water-wet and mixed-wet systems with the aim of using it to simulate oil recovery at the field scale. The equations that were able to correlate water-wet and mixed-wet recoveries require further research.

5. Experiments should be carried out in a stack of blocks with different degrees of capillary discontinuity to study the effect of oil re-infiltration on imbibition recovery in water-wet and mixed-wet systems.

6. Realistic simulation needs to include viscous, gravity and capillary forces to predict imbibition recovery and water displacement in fractured reservoirs. In this work we have only considered the effects of capillary forces. A similar study including viscous and gravity forces could be performed.
6. Bibliography


Appendix-E: Simulation data sets, results and sample calculations

E.1. Chapter : 2

E.1.1. 1D base model, Eclipse input data

--- One Dimensional Counter-current Imbibition
--- WATER-WET SLAB
--- BASE CASE (Kr & PC from SPE 18283)
--- Matrix Swi = SWC = 40 %
--- A horizontal water-wet slab with all faces closed except one end
--- that is in touch with a region (with fracture properties) full of water.
---
DEBUG
 0 0 0 1 0 0 1 0 0 1 /
RUNSPEC

TITLE
<< One Dimensional Counter-current Imbibition >>

DIMENS
-- NX NY NZ
  1 1 43 /

"ONLY OIL AND WATER EXIST"

OIL
WATER

"USING LAB UNITS"

LAB

"ASSUME TWO REGIONS WITH THE SAME FLUID PROPERTIES"

EQLDIMS
  2 /

TABDIMS
  2 1 15 15 2 /

START
  1 'JAN' 2002 /
FMTOUT
FMTIN
UNIFOUT
UNIFIN

GRID

DZ
  1.2 20* .3 22* 1 /

EQUALS
'DX'  2.1 /
'DY'  6.1 /
Appendix-C

'PORO'  1.0  1 1 1 1 1 1 / FRACTURE PROPERTIES
'TOPS'  0 /
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

'PORO'  0.233  1 1 1 2 43 / MATRIX PROPERTIES
'PERMX' 124 /
'PERMY' 124 /
'PERMZ' 124 /

/ PSEUDOS
RPTGRID 1 1 1 1 1 0 1 1 0 1 0 1 1 1 1 1 0
0 0 0 0 0 0 1 /
INIT
PROPS

"USING SIMILAR FLUID PROPERTIES FOR TWO REGIONS"

DENSITY
-- Densities @ surface condition gr/cc
-- Oil Water GAS
  0.76  1.09  7.08E-04 /

ROCK
-- Pref, atm Ca, 1/atm
  100.00  308E-04 /

PVDO
-- PVT PROPERTIES OF DEAD OIL
-- Press, atm Bo, rcc/scct Vis-oil, cp
-- 0.00000  1.00004  1.50000
  100.000  1.00002  1.50001
  3600.00  1.00000  1.50002 /

PVTW
-- WATER PROPERTIES
-- Pref, atm Bw, rcc/scct Cw, 1/atm Vis-w, cp Cv, 1/atm
-- 100.0000  1.00000  0.00E-05  1.200000  0.00E-01 /

-- SWOF
-- fracture
-- Sw  Krw  Kro  Pcw-o
  0.0  0.0  1.0  0.0
  1.0  1.0  0.0  0.0 /

-- matrix
-- Sw  Krw  Kro  Pcw-o
  .4  0.0  .3  .112
  .42  0.002  .23  .097
  .45  0.0051  .16  .078
  .47  0.009  .13  .067
  .50  0.014  .09  .054
  .53  0.019  .06  .039
  .55  0.024  .04  .035
  .57  0.028  .02  .032
  .578  0.031  .00  .031
/
RPTPROPS 1 1 1 1 1 1 1 1 /

REGIONS

"DEFINE TWO REGIONS FOR MATRIX (R-2) AND FRACTURE (R-1)"
EQUALS
'FIPNUM' 1, 1, 1, 1, 1, 1, 1, 1/
'FIPNUM' 2, 1, 1, 1, 1, 2, 43 /
--  " USE DIFFERENT SATURATION TABLES FOR EACH REGION"
'SATNUM' 1, 1, 1, 1, 1, 1, 1, 1/
'SATNUM' 2, 1, 1, 1, 1, 2, 43 /
BOX
  1  1  1  1  1  43 /
EQLNUM
  1*1  42*2 /
RPTREGS
  0  1  0  0  0  0  0  0  0 /
SOLUTION
  BOX
  PRESSURE
  1*1.0 /
  SWAT
  1*1.0 /
  BOX
  1  1  1  1  2  43 /
PRESSURE
  42*1.0 /
SWAT
  42*0.4 /
RPTSOL
  1  1  0  0  0  0  2  1  0  0 /
SUMMARY
  -------------------------------
  OUTPUT IN EXCEL FORMAT
  EXCEL
  -- Show average oil saturation in regions
  ROSAT
  1  2 /
  -- Show average oil pressure in regions
  RPR
  1  2 /
  -- Show oil exchange between regions
  ROFTL
  2  1 /
/  RPTONLY
SCHEDULE
  -------------------------------
  TSTEP
  50*.1 /
  TSTEP
  50*.5 /
  TSTEP
  50*1 /
  TSTEP
  50*2 /
  TSTEP
  50*3 /
END
E.1.2.  2D base model, Eclipse input data

-- Two Dimensional Counter-current Imbibition
-- Data from SPE 18283
-- Matrix Swi = 40%
-- A horizontal square shape water-wet slab with all faces open and in
-- touch with a region (with fracture properties) full of water.
--
DEBUG
0 0 0 1 0 0 1 0 0 1 /
RUNSPEC

TITLE << TWO Dimensional Counter-current Imbibition >>

DIMENS
-- NX  NY  NZ
  --  11 11  1 /
  --  5  5  1 /

LGR
-- MAXLGR  MAXCLS  MCOARS  MAMALG  MXLALG
  25  45000  0  2  4 /

-- "ONLY OIL AND WATER EXIST"

OIL

WATER
-- "USING LAB UNITS"

LAB
-- "ASSUME TWO REGION WITH SAME FLUID PROPERTIES"

EQLDIMS
  5 /

TABDIMS
  2 1 15 15 5 /

START
  1 'JAN' 2002 /

GRID

-- ---------------------------------------------------------------
DX
  1 3*3  1
  1 3*3  1
  1 3*3  1
  1 3*3  1
  1 3*3  1 /

DY
  5*1 15*3 5*1 /

EQUALS
' DZ' 1 /
'TOPS' 0 / HORIZONTAL SYSTEM
'PORO' 0.233 2 4 2 4 1 1 / MATRIX PROPERTIES
'PERMX' 124 /
'PERMY' 124 /
'PERMZ' 124 /
Appendix-C

'PORO' 1.0 1 5 1 1 1 1 / FRACTURE PROPERTIES (R-1)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /
'PORO' 1.0 1 1 2 4 1 1 / FRACTURE PROPERTIES (R-2)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /
'PORO' 1.0 1 5 5 5 1 1 / FRACTURE PROPERTIES (R-3)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /
'PORO' 1.0 5 5 2 4 1 1 / FRACTURE PROPERTIES (R-4)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

CARFIN

ENDFIN
CARFIN

ENDFIN
CARFIN

ENDFIN
CARFIN

ENDFIN
CARFIN

ENDFIN
CARFIN

ENDFIN
CARFIN

ENDFIN

ANALGAM

'LGR**' /

PSEUDOS

RPTGRID

INIT
PROPS

-- "USE SIMILAR FLUID PROPERTIES FOR TWO REGIONS"

DENSITY

-- Densities @ surface condition gr/cc
-- Oil Water GAS
  0.760 1.09 7.0E-04 /

ROCK

-- Pref, atma Cf, l/atm
 100.00 .30E-04 /

PVDO

-- PVT PROPERTIES OF DEAD OIL
-- Press, atma Bo, rcc/sec Vis-oil, cp
-- --------- --------- ---------
-- 0.00000 1.00004 1.50000
-- 100. 1.00002 1.50001
-- 3600.00 1.00000 1.50002 /

PVW

-- WATER PROPERTIES
-- Pref, atma Bw, rcc/sec Cw, l/atm Vis-w, cp Cv, l/atm
-- --------- --------- --------- ---------
-- 100.0000 1.00000 0.00E-05 1.20000 0.00E-01 /

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
Appendix-C

-- Fracture
-- Sw Kw Kro Pcw-o
0.0 0.0 1.0 0.0
1.0 1.0 0.0 0.0 /

-- MATRIX
-- Sw Kw Kro Pcw-o
.4 0.0 .3 .112
.42 0.002 .23 .097
.45 0.0051 .16 .078
.47 0.0009 .13 .067
.50 0.014 .09 .054
.53 0.019 .06 .039
.55 0.024 .04 .035
.57 0.028 .02 .032
.578 0.031 .00 .031 /

RPTPROPS
1 1 1 1 1 1 1 1 /

REGIONS

"DEFINE ONE MATRIX(R-5) AND FOUR PIC.FRACTURE REGIONS"

EQUALS

'FIPNUM ' 1, 1, 5, 1, 1, 1, 1 /
'FIPNUM ' 2, 1, 1, 2, 4, 1, 1 /
'FIPNUM ' 3, 1, 5, 5, 1, 1 /
'FIPNUM ' 4, 5, 1, 2, 4, 1, 1 /
'FIPNUM ' 5, 2, 4, 2, 4, 1, 1 /

"USE DIFFERENT SATURATION TABLES FOR EACH REGION"

'SATNUM ' 1, 1, 5, 1, 1, 1, 1 /
'SATNUM ' 1, 1, 2, 4, 1, 1 /
'SATNUM ' 1, 5, 5, 1, 1 /
'SATNUM ' 1, 2, 4, 1, 1 /

BOX
1 5 1 1 1 1 /
EQLNUM
5*1 /
BOX
1 1 2 4 1 1 /
EQLNUM
3*2 /
BOX
1 5 5 5 1 1 /
EQLNUM
5*3 /
BOX
5 5 2 4 1 1 /
EQLNUM
3*4 /
BOX
2 4 2 4 1 1 /
EQLNUM
9*5 /

RPTREGS
0 1 0 0 0 0 0 0 /

SOLUTION

-- EQUAL INITIAL HYDROSTATIC PRESSURE

PRESSURE
25*1.0 /

-- INITIAL WATER SATURATION IS 1.0 IN FRACTURES AND .2 IN MATRIX
BOX
1 5 1 1 1 1 /
SWAT
5*1 /
BOX
1 1 2 4 1 1 /
SWAT 
BOX 
SWAT 
BOX 
SWAT 
BOX 
SWAT 
RPT SOL 
1 1 1 1 0 0 0 0 2 1 0 0 /

SUMMARY ================================================================

-- OUTPUT IN EXCEL FORMAT

EXCEL

-- SHOW AVERAGE OIL SATURATION IN REGIONS

RO SAT
-- 1 2 3 4 5 /
5 /

-- SHOW AVERAGE OIL PRESSURE IN REGIONS

-- RPR
-- 1 2 3 4 5 /

-- SHOW OIL EXCHANGE BETWEEN REGIONS

ROPTL
5 1 /
5 2 /
5 3 /
5 4 /

RPTONLY

SCHEDULE ================================================================

TSTEP
50*.001 /

TSTEP
20*.02 20*.1 10*.5 /
TSTEP
50*1 /
TSTEP
50*10 /

-- *************** END OF DATA SET **************************************

END
E.1.3.  1D network data, Eclipse input data

-- One Dimensional Counter-current Imbibition
-- WATER-WET SLAB
-- DATA FROM Jackson et al. Swi = Swc = 25%

-- A vertical water-wet slab with all faces closed except one end
-- that is in touch with a region(with fracture properties) full of water.
--
-- DEBUG
0 0 0 1 0 0 0 1 0 0 1 /

RUNSPEC

TITLE

<< One Dimensional Counter-current Imbibition >>

--

DIMENS

-- NX  NY  NZ
  1  1  43 /
-- 1  1  2 /

-- "ONLY OIL AND WATER EXIST"

OIL

WATER

-- "USING LAB UNITS"

LAB

-- "ASSUME TWO REGION WITH SAME FLUID PROPERTIES"

EQLDIMS

2 /

TABDIMS

2  1  100  100  2 /

START

1 'JAN' 2002 /

FMTOUT

FMTIN

UNIFOUT

UNIFIN

GRID

3.0  20* .3  22*1 /

EQUALS

'DX'  2.1 /
'Dy'  6.1 /

'PORO'  1.0  1 1 1 1 1 1 / FRACTURE PROPERTIES
'TOPS'  0 /
'PERMX'  50000 /
'PERMY'  50000 /
'PERMZ'  50000 /

'PORO'  0.20  1 1 1 1 2 43 / MATRIX PROPERTIES
'PERMX'  3148 /
'PERMY'  3148 /
'PERMZ'  3148 /

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
PSEUDOS

RPTGRID

\[
\begin{array}{cccccccccccc}
1 & 1 & 1 & 1 & 1 & 1 & 1 & 0 & 1 & 1 & 0 & 1 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
\end{array}
\]

INIT

---

PROPS

"USE SIMILAR FLUID PROPERTIES FOR TWO REGIONS"

DENSITY

- Densities @ surface condition gr/cc
- Oil: 0.835
- Water: 1.01
- GAS: 7.0E-04

ROCK

- Pref, atm: 100
- Cf, 1/atm: 0.30E-04

PVDO

- PVT PROPERTIES OF DEAD OIL
- Press, atm: 0.00000
- Bo, rcc/scc: 1.00000
- Vis-oil, cp: 1.40000

PVTW

- WATER PROPERTIES
- Pref, atm: 100.0000
- Bw, rcc/scc: 1.00000
- Cw, 1/atm: 0.00E-05
- Vis-w, cp: 1.05000
- Cv, 1/atm: 1.00000

SWOF

- Fracture
- Sw: 0.0
- Krw: 1.0
- Kro: 0.0
- Pcw-o: 0.0

- Matrix
- Sw: 0.0
- Krw: 1.0
- Kro: 0.0
- Pcw-o: 0.0

---

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
0.409242 2.39E-03 6.09E-01 9.98E-03
0.414272 2.66E-03 5.96E-01 9.78E-03
0.419305 2.87E-03 5.80E-01 9.62E-03
0.424657 3.15E-03 5.69E-01 9.48E-03
0.429741 3.49E-03 5.54E-01 9.35E-03
0.434935 3.87E-03 5.40E-01 9.22E-03
0.440054 4.16E-03 5.09E-01 9.07E-03
0.445028 4.68E-03 4.98E-01 8.94E-03
0.450257 5.03E-03 4.81E-01 8.82E-03
0.455326 5.35E-03 4.71E-01 8.71E-03
0.460365 5.78E-03 4.52E-01 8.58E-03
0.465582 6.30E-03 4.40E-01 8.48E-03
0.470854 6.92E-03 4.28E-01 8.36E-03
0.475946 7.24E-03 4.19E-01 8.28E-03
0.481057 7.71E-03 4.11E-01 8.16E-03
0.486172 8.58E-03 3.97E-01 8.07E-03
0.4914 9.17E-03 3.78E-01 7.96E-03
0.496434 9.73E-03 3.68E-01 7.87E-03
0.501518 1.06E-02 3.56E-01 7.79E-03
0.506589 1.15E-02 3.47E-01 7.71E-03
0.511638 1.29E-02 3.41E-01 7.65E-03
0.516666 1.38E-02 3.28E-01 7.57E-03
0.522521 1.47E-02 3.16E-01 7.48E-03
0.528202 1.56E-02 3.06E-01 7.39E-03
0.534008 1.69E-02 2.91E-01 7.33E-03
0.539188 1.78E-02 2.81E-01 7.25E-03
0.544256 1.92E-02 2.71E-01 7.16E-03
0.549399 2.03E-02 2.57E-01 7.07E-03
0.554592 2.14E-02 2.49E-01 7.00E-03
0.5602 2.39E-02 2.42E-01 6.92E-03
0.565387 2.52E-02 2.37E-01 6.86E-03
0.570563 2.74E-02 2.25E-01 6.77E-03
0.575793 2.92E-02 2.04E-01 6.71E-03
0.581213 3.13E-02 1.99E-01 6.64E-03
0.58613 3.30E-02 1.92E-01 6.57E-03
0.591975 3.59E-02 1.83E-01 6.50E-03
0.597286 3.79E-02 1.79E-01 6.45E-03
0.602503 4.03E-02 1.72E-01 6.38E-03
0.607825 4.26E-02 1.66E-01 6.31E-03
0.613556 4.47E-02 1.47E-01 6.27E-03
0.619337 4.62E-02 1.39E-01 6.21E-03
0.624023 4.96E-02 1.26E-01 6.16E-03
0.629437 5.13E-02 1.22E-01 6.10E-03
0.634678 5.55E-02 1.14E-01 6.04E-03
0.641303 5.94E-02 1.05E-01 5.99E-03
0.6465 6.10E-02 9.32E-02 5.93E-03
0.651659 6.41E-02 8.96E-02 5.86E-03
0.656954 6.94E-02 8.38E-02 5.84E-03
0.662092 7.23E-02 8.62E-02 5.80E-03
0.667556 7.75E-02 8.40E-02 5.74E-03
0.673204 8.07E-02 7.98E-02 5.70E-03
0.678343 8.53E-02 7.14E-02 5.65E-03
0.685 8.84E-02 6.56E-02 5.60E-03
0.692563 9.35E-02 5.66E-02 5.55E-03
0.699056 9.84E-02 5.24E-02 5.47E-03
0.7014 1.06E-01 4.76E-02 5.42E-03
0.706872 1.11E-01 3.74E-02 5.37E-03
0.71196 1.16E-01 2.19E-02 5.34E-03
0.71757 1.21E-01 1.95E-02 5.28E-03
0.722617 1.26E-01 1.86E-02 5.19E-03
0.727779 1.34E-01 1.65E-02 5.14E-03
0.733174 1.43E-01 1.56E-02 5.05E-03
0.738516 1.48E-01 1.50E-02 4.99E-03
0.744585 1.57E-01 4.50E-03 4.88E-03
0.750565 1.65E-01 0.008+00 6.50E-04

/ 
RPTPROPS
1 1 1 1 1 1 1 1 1 /

REGIONS

" DEFINE TWO REGIONS FOR MATRIX (R-2) AND FIC.FRAC.TURE (R-1)"

EQUALS

'FIPNUM '1 , 1 , 1 , 1 , 1 , 1 /
'FIPNUM '2 , 1 , 1 , 1 , 1 , 43 /
"USE DIFFERENT SATURATION TABLES FOR EACH REGION"

'SATNUM' 1 1 1 1 1 1 /
'SATNUM' 2 1 1 1 1 2 43 /

BOX
  1 1 1 1 1 43 /
  1 1 1 1 1 2 /

EQLNUM
  1*1 42*2 /

RPTREGS
  0 1 0 0 0 0 0 0 0 0 /

SOLUTION

BOX
  1 1 1 1 1 1 /

PRESSURE
  1*1.0 /
SWAT
  1*1.0 /

BOX
  1 1 1 1 2 43 /
  1 1 1 1 2 2 /

PRESSURE
  42*1.0 /
SWAT
  42*0.249686 /

RPTSOL
  1 1 1 0 0 0 2 1 0 0 /

SUMMARY

-- OUTPUT IN EXCEL FORMAT

-- SHOW AVERAGE OIL SATURATION IN REGIONS

ROSAT
  1 2 /

-- SHOW AVERAGE OIL PRESSURE IN REGIONS

RPR
  1 2 /

-- SHOW OIL EXCHANGE BETWEEN REGIONS

ROFTL
  2 1 /

-- SHOW SATURATION AND PRESSURE OF GRID BLOCKS

RPTONLY

SCHEDULE

TSTEP
  50*.005
/NEW
TSTEP
  50*.05
/NEW
TSTEP
  50*.1
/NEW
TSTEP
  50*.5
/NEW
TSTEP  50*1
/NEW TSTEP  50*2
/NEW TSTEP  50*2
/NEW TSTEP  50*3
/NEW TSTEP  50*5
/NEW

*****END OF DATA SET**********************************************
END
E.1.4. 2D network data, Eclipse input data

--- Two Dimensional Counter-current Imbibition
--- Data From Jackson et al.
--- Matrix Swi = 25%
--- A horizontal square shape water-wet slab with all faces open and in
--- touch with a region (with fracture properties) full of water.
---
--- DEBUG
0 0 0 1 0 0 1 0 0 1 /

RUNSPEC

TITLE << TWO Dimensional Counter-current Imbibition >>

DIMENS
-- NX NY NZ
5 5 1 /

LGR
-- MAXLGR MAXCLS MCOARS MAMALG MXLALG
25 90000 0 2 4 /

--NSTACK
--50 /

-- "ONLY OIL AND WATER EXIST"

OIL

WATER
-- "USING LAB UNITS"

LAB
-- "ASSUME TWO REGION WITH SAME FLUID PROPERTIES"

EQLDIMS
5 /

TABDIMS
2 1 100 100 5 /

START
1 'JAN' 2002 /

NSTACK
35 /

FMTOUT

FMTIN

UNIFOUT

UNIFIN

GRID

DX
1 3*3 1
1 3*3 1
1 3*3 1
1 3*3 1
1 3*3 1 /

DY
5*1 15*3 5*1 /

EQUALS 'DZ' 1 /
Appendix-C

'TOPS' 0 / HORIZONTAL SYSTEM

'PORO' 0.20 2 4 2 4 1 1 / MATRIX PROPERTIES
'PERMX' 3148 /
'PERMY' 3148 /
'PERMZ' 3148 /

'PORO' 1.0 1 5 1 1 1 1 / FRACTURE PROPERTIES (R-1)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

'PORO' 1.0 1 1 2 4 1 1 / FRACTURE PROPERTIES (R-2)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

'PORO' 1.0 1 5 5 5 1 1 / FRACTURE PROPERTIES (R-3)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

'PORO' 1.0 5 5 2 4 1 1 / FRACTURE PROPERTIES (R-4)
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /

CARFIN

RPTGRID

1 1 1 1 1 0 1 1 0 1 0 1 1 1 0
0 0 0 0 0 0 0 1 / INIT

PROPS

"USE SIMILAR FLUID PROPERTIES FOR TWO REGIONS"

DENSITY

-- Densities @ surface condition gr/cc
-- Oil Water GAS
0.835 1.01 7.0E-04 /

ROCK

-- Pref, atma Cf, 1/atm
100.00 .30E-04 /

PVDO

-- PVT PROPERTIES OF DEAD OIL
-- Press, atma Bo, rcc/sec Vis-oil, cp
-- 0.00000 1.00004 1.40000
Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani

<table>
<thead>
<tr>
<th>WATER PROPERTIES</th>
<th>1.00000</th>
<th>0.00E-05</th>
<th>1.05000</th>
<th>0.00E-01</th>
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<tr>
<td>Pref, atm</td>
<td>100.000</td>
<td>1.00000</td>
<td>1.00000</td>
<td>1.40001</td>
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<tr>
<td>Bw, rcc/sec</td>
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<td>0.00E-05</td>
<td>1.05000</td>
<td>0.00E-01</td>
</tr>
<tr>
<td>Cw, 1/atm</td>
<td>1.00000</td>
<td>0.00E-05</td>
<td>1.05000</td>
<td>0.00E-01</td>
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<tr>
<th>SWOF</th>
<th>Fracture</th>
<th>Sw</th>
<th>Krw</th>
<th>Kro</th>
<th>Pcw-o</th>
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<td>0.0</td>
<td>0.0</td>
<td>1.0</td>
<td>0.0</td>
<td>0.0</td>
<td>/</td>
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<table>
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<tr>
<th>MATRIX</th>
<th>Sw</th>
<th>Krw</th>
<th>Kro</th>
<th>Pcw-o</th>
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<td>9.96E-01</td>
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<td>9.86E-01</td>
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<tr>
<td>0.276136</td>
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<td>2.00E-02</td>
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<td>8.65E-01</td>
<td>1.71E-02</td>
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<td>1.64E-02</td>
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<td>7.90E-01</td>
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Analysis, Scaling and Simulation of Counter-Current Imbibition  
H. Sh. Behbahani
3*4 /
BOX 2 4 2 4 1 1 /
EQLNUM 9*5 /
RPTREGS 0 1 0 0 0 0 0 0 0 0 0 /
SOLUTION ==-------------------------------------------------------------------
-- EQUAL INITIAL HYDROSTATIC PRESSURE
PRESSURE 25*1.0 /
-- INITIAL WATER SATURATION IS 1.0 IN FRACTURES AND .2 IN MATRIX
BOX 1 5 1 1 1 1 /
SWAT 5*1 /
BOX 1 1 2 4 1 1 /
SWAT 3*1 /
BOX 1 5 5 5 1 1 /
SWAT 5*1 /
BOX 5 5 2 4 1 1 /
SWAT 3*1 /
BOX 2 4 2 4 1 1 /
SWAT 9*0.25 /

RPTSOL 1 1 0 0 0 2 1 0 0 /
SUMMARY ==-------------------------------------------------------------------
-- OUTPUT IN EXCEL FORMAT
EXCEL
-- SHOW AVERAGE OIL SATURATION IN REGIONS
ROSAT 5 /
-- SHOW AVERAGE OIL PRESSURE IN REGIONS
--RPR -- 1 2 3 4 5 /
-- SHOW OIL EXCHANGE BETWEEN REGIONS
ROFTL 5 1 /
5 2 /
5 3 /
5 4 /
/
RPTONLY
SCHEDULE ==-------------------------------------------------------------------

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E.1.5. 2D fracture/matrix transfer simulation, Eclipse input data for instantly filled regime, Fig. 2.18

Data from SPE 18283

Assumption: Equal water and Oil viscosity

Matrix Blocks connected to two sides of a long fracture

Water injected in the fracture and produced from the well completed in last fracture region

122 region defined in each side of the Fracture

X-Gridding similar to SPE 18283 models

DEBUG

RUNSPEC

TITLE

<< TWO Dimensional Counter-current Imbibition in a series of Blocks >>

DIMENS

NX NY NZ
85 122 1 /

"ONLY OIL AND WATER EXIST"

"USING LAB UNITS"

"ASSUME 42 REGION WITH SAME FLUID PROPERTIES"

EQLDIMS
245 /

TABDIMS
2 1 22 22 245 /

START
1 'JAN' 2002 /

IMPES

FMTOUT

FMTIN

UNIFOUT

UNIFIN

GRID

DX

22*1 20*.3 .7 20*.3 22*1
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Analysis, Scaling and Simulation of Counter-Current

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H. Sh. Behbahani




\[
\begin{align*}
22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
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22*1 & \ 20*3 \ & .7 & \ 20*3 \ & 22*1 \\
\end{align*}
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'TOPS' 0 /
'HORIZONTAL SYSTEM

'\text{PORO}' 0.233 1 42 1 122 1 1 /
'\text{PERMX}' 1 /
'\text{PERMY}' 1 /
'\text{PERMZ}' 1 /

'\text{PORO}' 0.233 44 85 1 122 1 1 /
'\text{PERMX}' 1 /
'\text{PERMY}' 1 /
'\text{PERMZ}' 1 /

'\text{PORO}' 1.0 43 43 1 122 1 1 /
'\text{PERMX}' 15000 /
'\text{PERMY}' 15000 /
'\text{PERMZ}' 15000 /

\[/

\[\text{PSEUDOS}\]

\[\text{RPTGRID}\]

1 1 1 1 1 0 1 1 0 1 0 1 1 1 1 1 0
0 0 0 0 0 0 0 0 1 /

\[\text{INIT}\]

\[\text{PROPS}\]

\[\text{USE SIMILAR FLUID PROPERTIES FOR TWO REGIONS}\]

\[\text{DENSITY}\]

\[-\text{Densities @ surface condition gr/cc}\]

\[-\text{Oil Water GAS}\]

0.760 1.09 7.0E-04 /

\[\text{ROCK}\]

\[-\text{Pref, atma Cf, 1/atm}\]

100.00 .30E-04 /

\[\text{PVDO}\]

\[-\text{PVT PROPERTIES OF DEAD OIL}\]

\[-\text{Press, atma Bo, rcc/sec Vis-oil, cp}\]

0.00000 1.00004 1.50000

Analysis, Scaling and Simulation of Counter-Current Imbibition
H. Sh. Behbahani
### WATER PROPERTIES

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<th>Brw, rcc/scc</th>
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<th>Vis-w, cp</th>
<th>Cv, l/atm</th>
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Analysis, Scaling and Simulation of Counter-Current Imbibition
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Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani
Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition

"USE DIFFERENT SATURATION TABLES FOR EACH REGION"

"Matrix"
'SATNUM ' 2, 44, 85, 1, 122, 1, 1 / Matrix
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-- DEFINE THE REGIONS FOR AVERAGE SATURATIONS

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EQLNUM 42*1 /
BOX 44 85 1 1 1 1 /
EQLNUM 42*2 /

2ND ROW
BOX 1 42 2 2 1 1 /
EQLNUM 42*3 /
BOX 44 85 2 2 1 1 /
EQLNUM 42*4 /

3RD ROW
BOX 1 42 3 3 1 1 /
EQLNUM 42*5 /
BOX 44 85 3 3 1 1 /
EQLNUM 42*6 /

4TH ROW
BOX 1 42 4 4 1 1 /
EQLNUM 42*7 /
BOX 44 85 4 4 1 1 /
EQLNUM 42*8 /

5TH ROW
BOX 1 42 5 5 1 1 /
EQLNUM 42*9 /
BOX 44 85 5 5 1 1 /
EQLNUM 42*10 /

6TH ROW
BOX 1 42 6 6 1 1 /
EQLNUM 42*11 /
BOX 44 85 6 6 1 1 /
EQLNUM 42*12 /

7TH ROW
BOX 1 42 7 7 1 1 /
EQLNUM 42*13 /
BOX 44 85 7 7 1 1 /
EQLNUM 42*14 /

8TH ROW
BOX 1 42 8 8 1 1 /
EQLNUM 42*15 /
BOX 44 85 8 8 1 1 /
EQLNUM
Analysis, Scaling and Simulation of Counter-Current Imbibition  

H. Sh. Behbahani
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Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani
Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani
Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
Appendix-C

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Analysis, Scaling and Simulation of Counter-Current Imbibition  
H. Sh. Behbahani
Appendix-C

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
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<td>118 1</td>
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<td>85 119</td>
<td>119 1</td>
<td>1</td>
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</tbody>
</table>

---

*Analysis, Scaling and Simulation of Counter-Current Imbibition*  H. Sh. Behbahani
= 42*238 /

BOX 1 42 120 120 1 1 /
EQLNUM 42*239 /

BOX 44 85 120 120 1 1 /
EQLNUM 42*240 /

--- 120TH ROW

--- 121TH ROW

BOX 1 42 121 121 1 1 /
EQLNUM 42*241 /

BOX 44 85 121 121 1 1 /
EQLNUM 42*242 /

--- 121TH ROW

BOX 1 42 122 122 1 1 /
EQLNUM 42*243 /

BOX 44 85 122 122 1 1 /
EQLNUM 42*244 /

--- Fracture & Outlet

BOX 43 43 1 122 1 1 /
EQLNUM 122*245 /

RPTREGS 0 1 0 0 0 0 0 0 0 0 0 /

SOLUTION  ===========================================================

EQUAL INITIAL HYDROSTATIC PRESSURE

PRESSURE 10370*1.0 /

--- SET INITIAL WATER SATURATION IN FRACTURE AND IN MATRIX BLOCKS

BOX 1 42 1 122 1 1 /
SWAT 5124*0.4 /

BOX 44 85 1 122 1 1 /
SWAT 5124*0.4 /

BOX 43 43 1 122 1 1 /
SWAT 122*0.0 /

RPTSol 1 1 1 0 0 0 0 2 1 0 0 /

SUMMARY  ==============================================================

OUTPUT IN EXCEL FORMAT

EXCEL

NARROW
SHOW AVERAGE OIL SATURATION IN MATRIX REGIONS

RWSAT

<table>
<thead>
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</tr>
</tbody>
</table>

---------- well water inj rate
WWIR
'INJ'
/
---------- well Oil Production rate
WOPR
'PRD'
/
---------- well liquid production rate
WLPR
'PRD'
/
---------- well water cut
WWCT
'PRD'
/
---------- Field water and Oil in Place
--FWIP
--FOIPL
--/
RPTONLY

SCHEDULE

----------- WELSPECS
'INJ' 'G' 43 1 0 'WAT' /
'PRD' 'G' 43 122 0 'LIQ' /
/
----------- COMPDAT
'INJ' 43 1 1 'OPEN' 0 .000000 .4000 .00000 .0000 0.000E-01/
'PRD' 43 122 1 'OPEN' 0 .000000 .4000 .00000 .0000 0.000E-01/
/
----------- WCONTINUE
'INJ' 'WAT' 'OPEN' 'RATE' 20.0 /
/
----------- WCONPROD
-- 1-Name 2-Cond 3-CONTROL-mode 4-Oil-Rate-Targ 5-Water-Rate-Targ 6-Gas-
  Rate-Targ
  'PRD' 'OPEN' 'BHP' 1* 1* 1*
  /
  7-Liquid-Rate-Targ 8-Res-Vol-Targ 9-BHP-Targ(Lower-limit)atma
  1* 1* 1.0 /

Analysis, Scaling and Simulation of Counter-Current Imbibition

H. Sh. Behbahani
DIMPES
1*  .22  /

TSTOP
24*10  /

-- *************** END OF DATA SET *******************************
END
E.2. Chapter: 3

E.2.1. network model input data for ta=0 hour

Waterflooding and spontaneous Imbibition Experiments in aged Berea sandstone (ref: SPE 62507)
step 2: Primary drainage to Swi=15.5%, then wettability alteration, then waterflooding
Aging Time: 0 hours

TITLEx
SW15-ta0h
#

NETWORK
%../..../Data/optim
F ../data/Berea
#

RAND_SEED
874654
#

%-------------------------------------- Fluid Properties --------------------------------------

FLUID
% interfacial water oil water oil
% tension viscosity viscosity resistivity resistivity
% (mN/m) (cp) (cp) (Ohm.m) (Ohm.m)
24.2 0.967 39.25 1.2 1000.0
#

%-------------------------------------- Initial Condition --------------------------------------

INIT_CON_ANG
0.0 0.0 10.0 1.0
#

%-------------------------------------- Target --------------------------------------

SAT_TARGET
%finalSat maxPc maxDeltaSw maxDeltaPc calcKr calcI
0.155 1.0E21 0.1 5000.0 T F % PD
1.0 -1.0E21 0.05 5000.0 T F % WP
#

%-------------------------------------- Wettability Distribution Algor ----

EQUIL_CON_ANG
%model Minrecang maxrecang delta gama
1 50.0 92.0 10. 1.0
#

FRAC_CON_ANG
% fraction volBased min max delta eta
% =========== ========= === =========== ===
0.47 T 95.0 95.0 10.0 1.0
#

% How to select cluster 50
#
Appendix-C

--- Adjusting Processes ---

CLAY_EDIT
-.13521 %SWc=15 %
#

TRAPPING
% Inject fluid from allow drainage water mult fact in
% entry exit of dangling ends filled circ elem
T F T 0.0E-30
#

--- Pore Filling Algor ---

PORE_FILL_ALG
oren2 #
%oren1 #
%blunt1 #
%blunt2 #

PORE_FILL_WGT
0.0 0.5 1.0 2.0 5.0 10.0 % Oren1/2
%0.0 50E-6 50E-6 100E-6 200E-6 500E-6 % Blunt 1
%0 15000 15000 15000 15000 15000 % Blunt 2
#

--- Solution Area ---

CALC_BOX
0.4 0.9
#

PRO_BDRS
% calc kr using record press num press
% avg press profiles profiles
% T F 20
%

--- Solver ---

SOLVER_TUNE
% max min solver pre options
% iterations tolerance method conditioner file
25000 1.0E-12 cr ilu
#

SAT_COVERGENCE
% minNumFillings initStepSize cutBack maxInc maxStepSize stable disp
10 0.1 0.8 2.0 F
#

NET_OPTIMIZE
rcm T T ..../Data/binDBG
#

--- Output ---

OUTPUT
% PropertyOutput SwOutput
% F T
%
RES_FORMAT
excel
#

END DATA SET
E.2.2. network model input data for \( \tau_\text{a}=72 \text{ hour} \)

Waterflooding and spontaneous Imbibition Experiments in aged Berea sandstone (ref : SPE 62507)

step 2 : Primary drainage to \( \text{Sw}_i=15.2\% \), then wettability alteration, then waterflooding

Aging Time : 72 hours

%%%%%%%%%%%%%%%%%%%%%%%%%%%% General

TITLE
SW15-\( \tau_\text{a}72h \)

NETWORK
%../../Data/optim
F ../data/Berea

RAND_SEED
674654

%%%%%%%%%%%%%%%%%%%%%%%%%%%% Fluid Properties

FLUID
% interfacial water oil water oil
% tension viscosity viscosity resistivity resistivity
% (mN/m) (cp) (cp) (Ohm.m) (Ohm.m)
24.2 0.967 39.25 1.2 1000.0

%%%%%%%%%%%%%%%%%%%%%%%%%%%% Initial Condition

INIT_CON_ANG
0.0 0.0 10.0 1.0

%%%%%%%%%%%%%%%%%%%%%%%%%%%% Target

SAT_TARGET
%finalSat maxPc maxDeltaSw maxDeltaPc calcKr calcCl % PD
0.152 1.0E21 0.1 5000.0 T F % PD
1.0 -1.0E21 0.05 5000.0 T F % WF

%%%%%%%%%%%%%%%%%%%%%%%%%%%% Wettability Distribution Algor

EQUIL_CON_ANG
%model Minrecang maxrecang delta gama
1 72. 97.0 10. 1.0

FRAC_CON_ANG
% fraction volBased min max delta eta
% ===== ===== === === ===
0.538 T 140.0 180.0 10.0 1.0

% How to select
cluster 50

%%%%%%%%%%%%%%%%%%%%%%%%%%%% Adjusting Processes

CLAY_EDIT
-0.13521 %Swc=15 %

TRAPPING
Appendix-C

% Inject fluid from allow drainage water mult fact in
% T F of dangling ends filled circ elem 0.0E-30
#

%================================ Pore Filling Algor ====================

PORE_FILL_ALG
oren2 #
%oren1 #
%blunt1 #
%blunt2 #

PORE_FILL_WGT
0.0 0.5 1.0 2.0 5.0 10.0 % Oren1/2
%0.0 50E-6 50E-6 100E-6 200E-6 500E-6 % Blunt 1
%0 15000 15000 15000 15000 15000 % Blunt 2
#

%================================ Solution Area ======================

CALC_BOX
0.4 0.9 #

%PRS_BDRS
% calc kr using record press num press
% avg press profiles profiles
% T F 20 #

%================================ Solver ========================

SOLVER_TUNE
% max min solver pre options
% iterations tolerance method conditioner file
25000 1.0E-12 cr ilu #

SAT_COVERAGE
% minNumFillings initStepSize cutBack maxfncr stable disp
10 0.1 0.8 2.0 F #

NET_OPTIMIZE
rom T T../Data/binDBG #

%================================ Output =======================

%OUTPUT
% PropertyOutput SwOutput
% F T %

%RES_FORMAT
excel #

%**************************************** END DATA SET
E.2.3. Imbibition prediction for $ta=0$ hour, Eclipse data

---

One Dimensional Counter-current Imbibition
---
MIXED-WET SLAB
---
DATA FROM NETWORK MODEL
---
Case No 1 Matrix Swi = 15.5%, Aging Time = 0 hours
---
A horizontal mixed-wet slab with all faces closed except one end
that is in touch with a region (with fracture properties) full of water.
---
---
DEBUG
0001001001/
RUNSPEC
TITLE
<< One Dimensional Counter-current Imbibition >>
---
DIMENS
---
NX NY NZ
1 43 1 /
---
"ONLY OIL AND WATER EXIST"
---
OIL
WATER
---
"USING LAB UNITS"
---
LAB
---
"ASSUME TWO REGION WITH SAME FLUID PROPERTIES"
---
EQLDIMS
2 /
---
TABDIMS
2 1 150 150 2 /
---
START
1 'JAN' 2002 /
---
FMTOUT
---
PMTIN
---
UNIFOUT
---
UNIFIN
---
GRID
DX
DY
2.0 20*.07 22*.3 /
---
EQUALS
'TOPS' 0 /
'DX' 4 /
'DY' 1 /
'PORO' 1.0 1 1 1 1 1 / FRACTURE PROPERTIES
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /
'PORO' 0.207 1 1 2 43 11 / MATRIX PROPERTIES
'PERMX' 3131.21 /
'PERMY' 3131.21 /
'PERMZ' 3131.21 /
---
PSUDOS
RPTGRID
1 1 1 1 1 0 1 1 0 1 0 1 1 1 1 1 0
Appendix-C

---

"USE SIMILAR FLUID PROPERTIES FOR TWO REGIONS"

DENSITY
-- Densities @ surface condition gr/cc
   Oil   Water   GAS
 0.895  1.012  7.0E-04 /

ROCK
-- Pref, atma  CE, 1/atm
  100.00    .30E-04 /

PVDO
-- PVT PROPERTIES OF DEAD OIL
-- Press, atma  Bo, rcc/scc  Vis-oil, cp
  0.00000  1.00004  39.25000
  100.0000  1.00002  39.25001
   3600.00  1.00000  39.25002 /

PVTW
-- WATER PROPERTIES
-- Pref, atma  Bw, rcc/scc  Cw, 1/atm  Vis-w, cp  Cv, 1/atm
  100.0000  1.00000  0.00E-05  0.96700  0.00E-01 /

SWOF
-- Fracture
-- Sw  KRW  Kro  PCW-O
  0.0  0.0  1.0  0.0
  1.0  1.0  0.0  0.0 /

-- TO OBTAIN CASE WITH IMBIBITION, SET HIGH CAPILLARY PRESSURES IN MATRIX
-- Sw  KRW  Kro  PCW-O
    ------------------  ------------------
 0.154925  0.00E+00  9.97E-01  3.02E-01
 0.156074  1.97E-06  9.96E-01  1.18E-01
 0.157319  2.60E-06  9.95E-01  6.89E-02
 0.173112  5.16E-06  9.75E-01  1.95E-02
 0.222216  1.79E-05  8.79E-01  9.18E-03
 0.273283  8.35E-05  7.15E-01  6.58E-03
 0.323438  4.23E-04  5.05E-01  4.99E-03
 0.375157  1.42E-03  3.45E-01  3.61E-03
 0.425503  2.89E-03  2.72E-01  1.96E-03
 0.493407  1.60E-02  8.57E-02  -1.44E-03
 0.543703  1.90E-02  2.58E-03  -1.88E-03
 0.593892  2.48E-02  1.50E-03  -2.21E-03
 0.605277  2.49E-02  0.0  -2.22E-03 /

RPTPROPS
l  l  l  l  l  l  l  l  l  l /

REGIONS
---------------------------
-- "DEFINE TWO REGIONS FOR MATRIX (R-2) AND FIC.FRACUTURE (R-1)"

EQUALS
'FIPNUM' ' 1 , 1 , 1 , 1 , 1 , 1 , 1 , 1 , 1 /
'FIPNUM' ' 2 , 1 , 1 , 2 , 43 , 1 , 1 , 1 /

-- "USE DIFFERENT SATURATION TABLES FOR EACH REGION"
'SATNUM' ' 1 , 1 , 1 , 1 , 1 , 1 , 1 , 1 , 1 /
'SATNUM' ' 2 , 1 , 1 , 1 , 2 , 43 , 1 , 1 , 1 /

BOX
1 1 1 43 1 1 /

EQLNUM
1*1 42*2 /

RPTREGS

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
SOLUTION

BOX

PRESSURE

1*1.0 /

SWAT

1*1.0 /

BOX

PRESSURE

42*1.0 /

SWAT

42*.155 /

RPTSOL

SUMMARY

-- OUTPUT IN EXCEL FORMAT

EXCEL

-- SHOW AVERAGE OIL SATURATION IN REGIONS

ROSAT

1 2 /

-- SHOW AVERAGE OIL PRESSURE IN REGIONS

RPR

1 2 /

-- SHOW OIL EXCHANGE BETWEEN REGIONS

ROFTL

2 1 /

/ 

RPTONLY

SCHEDULE

TSTEP

50*.1 

/ TSTEP 

50*.5 

/ TSTEP 

50*1 

/ TSTEP 

50*5 

/ TSTEP 

50*10 

/ TSTEP 

50*50 

/ TSTEP 

50*100 

/ TSTEP 

50*200 

/ TSTEP 

50*500 

/ END
E.2.4. Imbibition prediction for $ta=72$ hour, Eclipse data

---
One Dimensional Counter-current Imbibition
MIXED-WET SLAB
DATA FROM NETWORK MODEL
Matrix $Swi = 15.2\%$, Aging Time $= 72$ hours
---
A horizontal mixed-wet slab with all faces closed except one end
that is in touch with a region (with fracture properties) full of water.
---
DEBUG
0 0 0 1 0 0 1 0 0 1 /
RUNSPEC
TITLE
<< One Dimensional Counter-current Imbibition >>
---
DIMENS
-- NX NY NZ
1 43 1 /
-- "ONLY OIL AND WATER EXIST"
OIL
WATER
--- "USING LAB UNITS"
LAB
--- "ASSUME TWO REGION WITH SAME FLUID PROPERTIES"
EQLDIMS
2 /
TABDIMS
2 1 150 150 2 /
START
1 'JAN' 2002 /
FMTOUT
FMTIN
UNIFOUT
UNIFIN
GRID
DIY
2.0  20*.07  22*.3 /
EQUALLS
'TOPS'  0 /
'DX'   4 /
'DZ'   1 /
'PORO' 1.0 1 1 1 1 1 1 / FRACTURE PROPERTIES
'PERMX' 50000 /
'PERMY' 50000 /
'PERMZ' 50000 /
'PORO' 0.207 1 1 2 43 1 1 / MATRIX PROPERTIES
'PERMX' 3131.21 /
'PERMY' 3131.21 /
'PERMZ' 3131.21 /
/
PSEUDOS
RPTGRID
1 1 1 1 1 0 1 1 1 0 1 0 1 1 1 1 1 0

Analysis, Scaling and Simulation of Counter-Current Imbibition  
H. Sh. Behbahani
INIT

PROPS

-- DENSITIES @ SURFACE CONDITION GR/CC
  -- OIL  WATER  GAS
  0.895  1.012  7.0E-04 /

ROCK
  -- Pref, atma    Cf, l/atm
  100.00        .302-04 /

PVDO
  -- PVT PROPERTIES OF DEAD OIL
  -- Pres, atma  Bo, rcc/scc  Vis-oil, cp
  0.0000       1.00004        39.25000 /
  100.0000     1.00002        39.25001 /

PVTW
  -- WATER PROPERTIES
  -- Pres, atma  Bw, rcc/scc  Cw, 1/atm  Vis-w, cp  Cv, 1/atm
  100.0000     1.00000        0.0080-05  0.96700  0.00E-01 /

SWOF
  -- NO CAPILLARY PRESSURES IN FRACTURE
  -- Sw  Krw  Kro  Pcw-o
  0.0  0.0  1.0  0.0
  1.0  1.0  0.0  0.0 /

-- MATRIX REL PERM & FC
  -- Sw  Krw  Kro  Pcw-o
  0.151933     0.0          9.98E-01  3.94E-01
  0.152786     7.43E-07     9.98E-01  6.38E-02
  0.154272     8.93E-07     9.96E-01  1.44E-02
  0.204636     1.14E-06     8.58E-01  2.45E-03
  0.253714     1.52E-06     6.74E-01  1.55E-03
  0.304716     2.70E-06     4.93E-01  9.65E-04
  0.354815     2.61E-06     3.57E-01  4.71E-04
  0.405398     2.17E-04     2.73E-01  1.06E-03
  0.494554     1.09E-02     1.36E-01  1.42E-02
  0.545075     2.18E-02     8.75E-02  1.60E-02
  0.595202     3.82E-02     4.82E-02  1.78E-02
  0.646101     7.29E-02     2.76E-02  1.96E-02
  0.696155     1.12E-01     1.47E-02  2.10E-02
  0.7113  1.34E-01     0.0          -2.18E-02 /

RPTPROPS

1 1 1 1 1 1 1 1 /

REGIONS

-- "DEFINE TWO REGIONS FOR MATRIX (R-2) AND FIC. FRACTURE (R-1)"

EQUALS

'FIPNUM' 1, 1, 1, 1, 1, 1, 1, 1 /
'SFIPNUM' 2, 1, 1, 2, 43, 1, 1 /

-- "USE DIFFERENT SATURATION TABLES FOR EACH REGION"

'SATNUM' 1, 1, 1, 1, 1, 1, 1, 1 /
'SSATNUM' 2, 1, 1, 2, 43, 1, 1 /

BOX

1 1 1 43 1 1 1 /

EQLNUM

1*1 42*2 /

RPTREGS

0 1 0 0 0 0 0 0 0 0 0
Appendix-C

SOLUTION

BOX
PRESSURE
  1 1 1 1 1 1 1 /
SWAT
  1*1.0 /

BOX
PRESSURE
  1 1 2 43 1 1 1 /
SWAT
  42*1.0 /
RPTSOL
  1 1 0 0 0 2 1 0 0 /

SUMMARY

-- OUTPUT IN EXCEL FORMAT
EXCEL

-- SHOW AVERAGE OIL SATURATION IN REGIONS
ROSAT
  1 2 /

-- SHOW AVERAGE OIL PRESSURE IN REGIONS
RPR
  1 2 /

-- SHOW OIL EXCHANGE BETWEEN REGIONS
ROPTL
  2 1 /

RPTONLY

SCHEDULE

TSTEP
  50*.1 /
TSTEP
  50*.5 /
TSTEP
  50*2 /
TSTEP
  50*5 /
TSTEP
  50*10 /
TSTEP
  50*50 /
TSTEP
  50*100 /
TSTEP
  50*500 /
TSTEP
  50*1000 /

-- END OF DATA SET END

Analysis, Scaling and Simulation of Counter-Current Imbibition  H. Sh. Behbahani
### E.2.5. Water-flooding calculations

#### ta = 48 hours

<table>
<thead>
<tr>
<th>Sw</th>
<th>Pc</th>
<th>Kwr</th>
<th>Kro</th>
<th>WOR</th>
<th>fw</th>
<th>dV/ds</th>
<th>PVI</th>
<th>Rwf</th>
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<td>0.364661</td>
<td>4.29E+01</td>
<td>3.61E+05</td>
<td>2.67E+01</td>
<td>0.004575</td>
<td>0.005455</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.414713</td>
<td>-2.73E+01</td>
<td>2.04E+04</td>
<td>1.81E+01</td>
<td>0.004596</td>
<td>0.004379</td>
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### Appendix-C

#### E.2.6. Relative permeabilities and capillary pressures for all wettability states

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