

Waterfront Imaging Using Self-Potential: Feasibility Assessment for a Kuwaiti Oil Reservoir

by

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Declaration of Originality

I declare that this thesis, **Waterfront Imaging Using Self-Potential: Feasibility Assessment for a Kuwaiti Oil Reservoir**, is entirely my own work under the supervision of Prof. Matthew D. Jackson. The work was performed in the Department of Earth Science and Engineering at Imperial College London. All published and unpublished material used in the thesis has been given full acknowledgment. This work has not been previously submitted, in whole or in part, to any other academic institution for a degree, diploma, or any other qualification.

The following articles, which form the basis for Chapters 3 and 5 of this thesis, have been published in Computers & Geosciences and Geophysical Research Letters, respectively:

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Alarouj, M., Collini, H., and Jackson, M. D., 2021. Positive zeta potential in sandstones saturated with natural saline brine. Geophysical Research Letters, 48, e2021GL094306.

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Abstract

Monitoring water movement towards production wells through downhole measurements of self-potential (SP) is a promising reservoir monitoring technology. However, over the past few years, there has been a concern on the applicability of this technology in real hydrocarbon reservoirs. Therefore, in this work, through the use of laboratory experiments and numerical modelling, we demonstrate and assess the feasibility of SP water monitoring in an actual hydrocarbon reservoir in Kuwait known as ‘Burgan Upper Sand’.

The experimental work comprises of measuring two main properties: (i) electrokinetic (EK) potential; and (ii) exclusion-diffusion (ED) potential, which are components of SP that are generated in response to pressure and concentration gradients, respectively. In the experiments, we use sandstone and shale rock samples with natural brines and crude oil collected from Burgan Upper Sand reservoir. We observe, for the first time, positive EK coupling coefficients and zeta potentials on fully water-saturated sandstone samples, caused by a positive zeta potential on dolomite and siderite mineral surfaces occupying part of the pore area, the adsorption of divalent ions in the natural brine onto quartz mineral surfaces and/or ion exchange with clay minerals. At the residual oil saturation, the measured EK coupling coefficients and zeta potentials exhibit different behaviour to fully water-saturated conditions, where the polarity was reversed in some samples.

The measured ED potential is diffusion dominated at high water saturations (i.e., full saturation and residual oil saturation), with the shale samples being slightly exclusive, consistent with previous studies. On the other hand, the measurements at low water saturations (i.e., irreducible water saturation) display a larger contribution from the exclusion potential. We also observe that the ion exclusion is dependent on the charge at the oil-brine interface, where a positively charged interface leads to positive ions exclusion and vice versa. These results have not been observed in previous ED potential studies. Our results highlight the importance of using realistic rock, water compositions and crude oil in experimental measurements and show that using experimentally-determined trends obtained from

quartz-dominated samples saturated with simple NaCl brines can induce significant errors in the data interpretation process.

To numerically assess the technology, we develop an SP solver that can simulate SP in subsurface reservoirs. Using that solver and the results from the experimental work, we simulate the SP in Burgan Upper Sand and test the effect of several production and reservoir parameters. The modelling results suggest that: (i) the magnitude of the SP signals are extremely low due to the high reservoir permeability in the clean sand channels; and (ii) this technology fails to locate SP anomalies in multi-layered reservoirs, caused by the high SP arising in the fastest front, which highly dissipates in the high conductivity bounding shale layers and masks any SP in other approaching fronts. Therefore, the feasibility assessment does not encourage proceeding to field implementation for Burgan Upper Sand and suggests that this technology can be more promising in lower permeability reservoirs.

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Publications

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Nomenclature

Symbol	Description	Unit
C_{ED}	Exclusion-Diffusion coupling coefficient	VM^{-1}
C_{EK}	Electrokinetic coupling coefficient	VPa^{-1}
C_{TE}	Thermoelectrical coupling coefficient	VK^{-1}
C_f	Brine concentration	M
C_r	Relative coupling coefficient	dimensionless
e	Charge of an electron	C
D	Diffusion Coefficient	m^2s^{-1}
F	Formation factor	dimensionless
g	Gravitational acceleration	ms^{-2}
h	Heat flux	Wm^{-2}
j	Charge flux	Am^{-2}
J	J function	dimensionless
k_B	Boltzmann constant	$1.38 \times 10^{-23} JK^{-1}$
k	Absolute permeability	m^2
k_{rw}	Water relative permeability	dimensionless
K	Thermal conductivity	$Wm^{-1}K^{-1}$
K_i	Hindrance diffusion coefficient	dimensionless
L_{ED}	Exclusion-Diffusion coupling term	$AM^{-1}m^{-1}$
L_{EK}	Electrokinetic coupling term	$APa^{-1}m^{-1}$
L_{TE}	Thermoelectrical coupling term	$AK^{-1}m^{-1}$
L	Length of a core sample	m
m	Cementation exponent	dimensionless
n	Saturation exponent	dimensionless
P_w	Water Pressure	Pa
P_c	Capillary pressure	Pa
q_w	Water Darcy velocity	ms^{-1}
r	Radius of a core sample	m

R	Electrical reactance	ohm
RQI	Rock quality index	$md^{0.5}$
S_w	Water saturation	dimensionless
S_{or}	Residual oil saturation	dimensionless
S_{wirr}	Irreducible water saturation	dimensionless
S_{wn}	Normalised water saturation	dimensionless
t_{Na}	Hittorf transport number for sodium ions	dimensionless
T	Temperature	K
U	Electrical potential	V
v	Concentration flux	$Ms^{-1}m^{-2}$
V_D	Pure diffusion potential	V
V_E	Pure exclusion potential	V
X	Electrical resistance	ohm
z_i	Charge number	dimensionless
Z	Electrical impedance	ohm
$\emptyset$	Porosity	dimensionless
σ_w	Brine conductivity	Sm^{-1}
μ_w	Water viscosity	$Pa.s$
Φ	Potential	Pa
ρ_w	Water Density	kg/m^3
σ_{fs}	Saturated rock conductivity	Sm^{-1}
σ_w	Water conductivity	Sm^{-1}
ε	Rock exclusion efficiency	dimensionless
ε_w	Brine permittivity	Fm^{-1}
ζ	Zeta potential	V
σ	Interfacial tension	Nm^{-1}
ϵ_x	Error in measured parameter x	Same as the unit of x

Chapter 1

Introduction

1.1 Motivation

It is inevitable that hydrocarbon reservoirs produced under water drive mechanisms or water flooding schemes will eventually suffer from water breakthrough. When encroaching water reaches a well, water cut increases, which leads to a decline in production performance and affects the entire system, from the reservoir to surface facilities. The presence of water in the vicinity of a producing well is expected to cause a decrease in the relative permeability of the hydrocarbon, which in turn causes a decrease in the productivity index. Along the well, scaling and/or corrosion issues might occur which can potentially lead to blockages or well integrity issues. Water production might also cause flow assurance issues at the surface, including pipeline scaling, corrosion and hydrate formation. Moreover, the surface processing facilities are usually designed with certain water handling capacities, which, if exceeded, could affect their performance. All these risk factors make water monitoring during hydrocarbon production critical. Notwithstanding recent technological advancements in the oil industry, most downhole water monitoring techniques can capture only the wellbore area, which allows for an extremely limited time for action once water is discovered. A few approaches have been developed for early detection of water encroachment, such as borehole radar imaging based on electromagnetic measurements (Chen and Oristaglio, 2002; Miorali et al., 2011) and resistivity measurements through electrode arrays (Bryant et al., 2002; Kharghoria et al., 2002; Dutta and Badr, 2008). However, the depth of investigation covered using these techniques is limited to several metres away from the wellbore. The only method available today for imaging water saturation across hydrocarbon reservoirs is the 4D seismic, which is inapplicable in many cases because of the large economic investment it requires (Lumley, 2001; Watts et al., 2006). In addition to its huge cost, the spatial and temporal resolution provided by 4D seismic technology is low.

Recent studies suggest that encroaching water can be detected remotely using downhole measurements of SP. In reservoirs that rely on water drive and water flooding, gradients in pressure, chemical composition and temperature occur when the encroaching water has a different temperature and composition from that of the formation water. These gradients give rise to SP, which can be defined as an electrical potential difference that acts to maintain formation electroneutrality. It has been suggested by several researchers that downhole measurements of SP can be used to detect water front movement from tens to hundreds of metres away from monitoring wells (Saunders et al., 2008; Gulamali et al., 2011; Jackson et al., 2012; Ijioma, 2016). They have suggested that these signals could be recorded using electrically insulated electrodes installed downhole permanently at a monitoring well.

These promising findings were based on numerical modelling of synthetic reservoirs and supported by experimental measurements of coupling coefficients (main petrophysical properties that control the generation of SP) using quartz dominated outcrop samples saturated simple NaCl brines (Jaafar et al., 2009; Vinogradov et al., 2010; Leinov and Jackson, 2014). However, real reservoirs comprise more complex conditions than that encountered in the synthetic models. Moreover, natural rocks and brines have more complex mineralogy and compositions, respectively, than that used in most of the previous experimental studies. Furthermore, The magnitude and the behaviour of SP in hydrocarbon reservoirs depend on a combination of reservoir and production parameters, including production rate, permeability, heterogeneity, geology, fluid properties and coupling coefficients (Jackson et al., 2012). Consequently, the resulting SP signals are specific to a certain reservoir producing under certain conditions. Thus, despite encouraging results, there are still uncertainties about field implementation owing to the complexities of real-life scenarios. To reduce these uncertainties and translate all previous efforts into a successful field trial, this dissertation comprises a presentation of the first feasibility assessment of SP monitoring in a real hydrocarbon reservoir.

1.2 Aims and Objectives

Ultimately, it is important to establish whether SP monitoring can predict water encroachment in real hydrocarbon reservoirs. Therefore, the aim of this PhD research is to assess the feasibility of SP monitoring in a real reservoir and identify its potential operational and economic benefits. The reservoir considered for this study is a sandstone reservoir located in Kuwait and it is producing under water flooding and natural water drive.

The feasibility assessment comprises numerical modelling of SP in a real hydrocarbon reservoir, as well as experimental measurements of the coupling coefficients, to investigate the uncertainties associated with reservoir and production conditions. The objectives of the modelling and experimental work are as follows

- Experimental work: to obtain realistic values of coupling coefficients on natural sandstone and shale samples collected from the reservoir of interest and saturated with representative natural brines and oils.
- Modelling work: To predict the likely magnitude of the SP signals in the field of interest under representative production and reservoir conditions.

This assessment can help to identify the benefits, as well as the limitations of implementing SP monitoring in the reservoir of interest and to detect production conditions at which measurable SP signals could be obtained.

1.3 Outline

Chapter 2 comprises an introduction to the origin of SP and the theory behind each of its three components: electrokinetic potential (EK), exclusion-diffusion potential (ED) and thermoelectrical potential (TE). Furthermore, it contains a succinct summary of the findings of previous studies that attempted to model SP in hydrocarbon reservoirs and discusses the uncertainties associated with it. In addition, previous research on the topic is outlined, with a focus on the coupling coefficients, which are the main petrophysical properties responsible for SP generation.

In chapter 3, the numerical approach used to model SP is introduced. The development of the MATLAB code (SP solver) to numerically simulate SP in subsurface reservoirs is then explicated. The code works as a post-processor, taking outputs from existing reservoir flow and transport simulators at a selected timestep, and calculating the SP throughout the reservoir model using simulated values of water saturation, pressure, concentration and temperature. The code differs from the earlier versions developed by Ijioma (2016), MacAllister et al. (2018) and Graham et al. (2018) in terms of its ability to model both faults in multiple directions and various polarity effects. Validation tests for the code on a 1D model and a demonstration case (to illustrate the applicability of the code) using a 3D model are also presented.

Chapter 4 constitutes an overview of the greater Burgan field, specifically the Upper Burgan reservoir at which this study was conducted. Reservoir rocks and fluids properties and production performance are discussed in detail. This chapter also presents the sector model used for the dynamic simulations and the fundamental assumptions made for its implementation. Dynamic simulation results are shown to be consistent with the actual production performance, and the ability of the model to simulate the basic aspects of water movement in the reservoir is ensured. Finally, the core plug selection process for the experimental work is detailed.

One of the main uncertainties of the modelling work conducted in previous studies is related to the coupling coefficients used in SP modelling. This provides the context for chapters 5 and 6, which include detailed characterisation of the EK and ED coupling coefficients, respectively. In these two chapters, the experimentally measured coupling coefficients for rock samples and fluids (oil and brine) collected from the Upper Burgan reservoir are presented. The coefficients are then used in chapter 7 to calibrate the SP model and predict more realistic results on the basis of the inputs from the reservoir samples.

Chapter 7 features a discussion of the SP modelling results for Greater Burgan. It starts with a local grid refinement study to select the optimum grid size, then simulates multiple production scenarios. The effect of flow rate, well spacing, brine salinity, shale conductivity, rock permeability and well

completion are discussed. Chapter 7 also contains a presentation of a calibration of the model based on the experimental work covered in chapters 5 and 6.

Finally, in Chapter 8, the findings from chapters 4–7 are summarised, followed by a discussion of their implications. This chapter ends with recommendations for potential future work.

Chapter 2

Background and Literature Review

2.1 Reservoir Monitoring

Reservoir monitoring is one of the key elements of reservoir management. The techniques used should be capable of providing a dynamic update on the reservoir's status with regard to pressure, temperature and saturation changes, which helps reservoir and production engineers to take the requisite actions for maintaining an optimum reservoir performance. The selection of the monitoring methods is specific to each case because there is no particular method that works for all cases. Selecting which method to use is subject to the objectives, cost, environmental aspects and implementation complexity. Usually, the integration of two or more techniques is considered to confirm and improve the quality and the interpretation of the acquired data. One of the challenging tasks of production and reservoir engineers is to monitor water encroachment towards production wells. In this section, the techniques utilised to track water movement and saturation changes in hydrocarbon reservoirs are described. These techniques include logging, seismic, fluid and tracer injection and electrical and electromagnetic methods.

2.1.1 Seismic monitoring

A simple version of seismic monitoring is vertical seismic profiling (VSP), which involves a seismic source placed at the surface near the well head and receivers placed in a well at a depth of interest. The layout of the sources and receivers can vary as per the objective (Figure 2.1). Once the seismic source is activated, the receivers start to record the seismic signals. The recorded signals involve mainly the travel time of the seismic wave from the source to the receivers (Figure 2.2). Interpreting VSP data helps to identify rock and fluid properties close to the wellbore and to confirm the near wellbore structure and stratigraphic layering (Hardage, 2000; Stewart, 2001; Odoh and Obiegbo, 2006). A more advanced version of the VSP is the VSEP (vertical seismoelectric profiling), which records seismoelectric signals in addition to seismic waves. Seismoelectric signals are generated when a seismic

wave propagates through an electrolyte, causing the suspended charged particles to separate (Glover and Jackson, 2010). More recently, distributed acoustic sensing (DAS) has been deployed in multiple wells in some field trials to record time-lapse seismic signals emitted by a source on the surface. This technology is referred to as 4D DAS VSP (Zhan et al., 2015; Nizkous et al., 2015). The principal advantages of these VSP methods are their simple and repetitive implementation; however, the depth of investigation is limited by the surface layout.

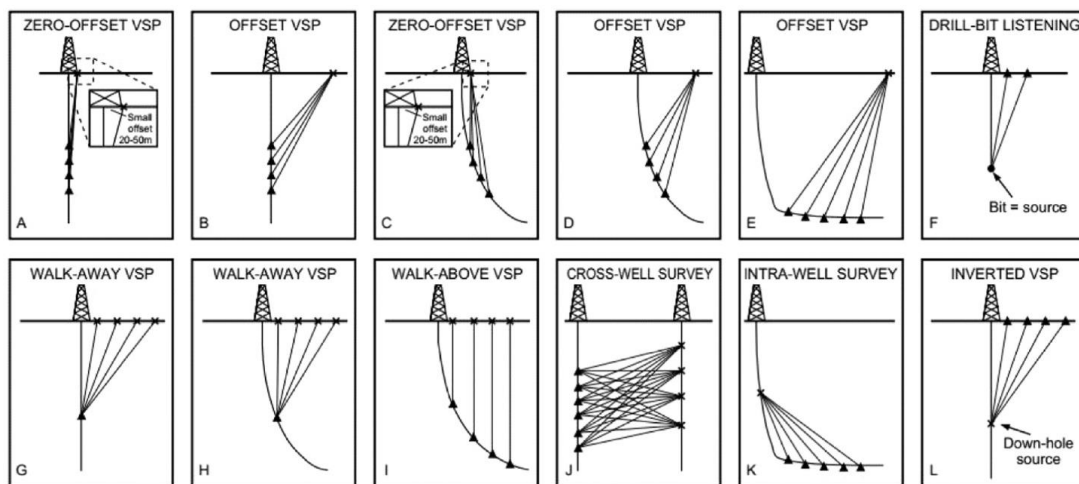


Figure 2.1: VSP examples (Geology, 2016).

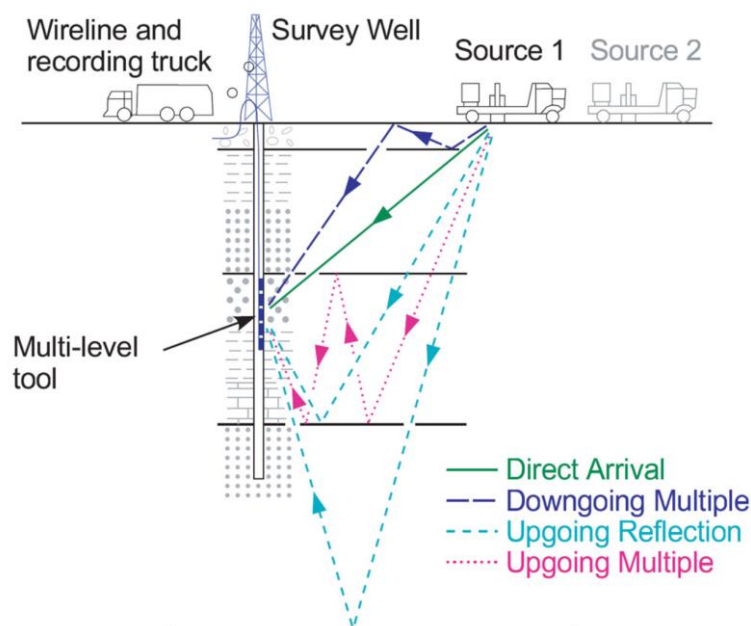


Figure 2.2: Schematic of a VSP survey indicating a survey well, seismic source, receiver, wireline and recording trucks (DiSiena et al., 1984).

Another form of seismic monitoring is the 4D seismic, which requires the distribution of seismic sources and receivers across a wide area at the surface (Figure 2.3). Time-lapse seismic surveys can help in detecting any variation in subsurface setups related to saturation changes over time (Lumley, 2001; Watts et al., 2006). The main advantage of 4D seismic surveys is that they can cover a wide surface area; however, the spatial and temporal resolution is low (Lumley, 2001; Watts et al., 2006). Moreover, it requires a huge economic investment.

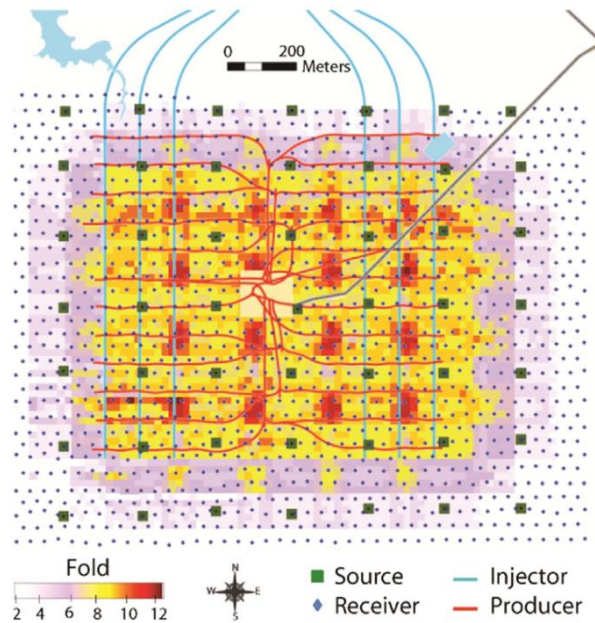


Figure 2.3: 4D seismic acquisition system (Berron et al., 2015).

2.1.2 Tracer injection

Tracers are detectable substances added to the injected fluids to track them, identify the flow paths, determine well-to-well connectivity and detect heterogeneities such as fractures and flow barriers (Hernandez et al., 2002). Tracer technology has been validated as extremely useful for monitoring and tracking water movement in hydrocarbon reservoirs (Zemel, 1995; Shook et al., 2009; Cheng et al., 2011; Cuauro et al., 2014). The implementation involves injecting small patches of tracers into injection wells and then continuously monitoring the production wells by collecting and analysing wellhead samples to detect the tracers (Tayyib et al., 2019). There are three main types of tracers: radioactive, chemical and dye tracers (Zecheru and Goran, 2013). The selected tracers should be chemically,

biologically and thermally stable, easily detectable at low concentration, safe and environmentally friendly and have a low adsorption tendency on rock surfaces (Tayyib et al., 2019). Radioactive tracers are highly detectable at low concentrations; however, they have a high risk of contact with the environment and personnel (Djuraev et al., 2017). Chemical tracers are more environmentally friendly; however, they should be designed carefully to avoid any interaction with the reservoir water. Dye tracers are also highly detectable at low concentrations, but they are adsorbed on rock surfaces. Hence, they are recommended for high-connectivity reservoirs (Djuraev et al., 2017).

If the selection of the tracer type is made carefully to satisfy the objectives, the implementation is fairly simple. The main limitation with regard to tracking water movement is that it can be detected only once it reaches the production wells and is sampled on the surface.

2.1.3 Pressure transient

Pressure transient tests in the form of injectivity and fall-off tests can be used to evaluate water flooding (Abbaszadeh and Kamal, 1989). These tests are usually used to determine near-wellbore damage, reservoir permeability and average reservoir pressure (Abbaszadeh and Kamal, 1989; Bratvold and Horne, 1990). Proper design and interpretation of a fall-off test can also help to determine saturation distribution and fluid movement (Kazemi et al., 1972; Abbaszadeh and Kamal, 1989; Daungkaew et al., 2009; Dastan et al., 2018). The depth of investigation for this approach can be hundreds of metres away from injection wells (Merrill et al., 1974; Ershaghi, 2008). The two most disadvantages of this method are i) the requirement to close the injector well, which might not be an acceptable operation and ii) the interference with surrounding wells in the case of small well spacing. With the evolution of the downhole sensor technology, injection wells can be equipped with permanent downhole pressure gauges to continuously monitor the pressure and utilise any closure time to perform fall-off tests (Ershaghi, 2008; Daungkaew et al., 2009).

2.1.4 Pulsed Neutron Capture logging

The pulsed neutron capture (PNC) tool generates a pulse of high-energy neutrons into the formation. These high-energy neutrons collide with the borehole environment and formation rocks and fluids,

causing them to reach a lower energy level called the ‘thermal energy level’. These low-energy neutrons are captured by various elements in formation. The PNC log measures the gamma rays that reach the detector of the PNC tool as a result of capturing these thermal neutrons (Figure 2.4). The chloride ions present in the high salinity brines have a remarkable ability to capture the thermal neutrons because they have bigger cross-sectional area and therefore release more gamma rays. Hence, the higher the salinity of the formation water, the greater the ability to capture thermal neutrons, which would imply high water saturation (Morris et al., 2005a, b; Conner et al., 2017; Ali et al., 2017). PNC logs have been proven to be highly effective for identifying hydrocarbon saturations behind the casing (Gournay and Maute, 1982; Madhavan et al., 2015; Ali et al., 2017). Time-lapse runs of the PNC log can detect saturation changes over the life of the well (Djuraev et al., 2017). The main limitation of PNC logs with regard to detecting saturation changes is the shallow depth of investigation, which is only several centimetres into the formation (Morris et al. 2005a, b).

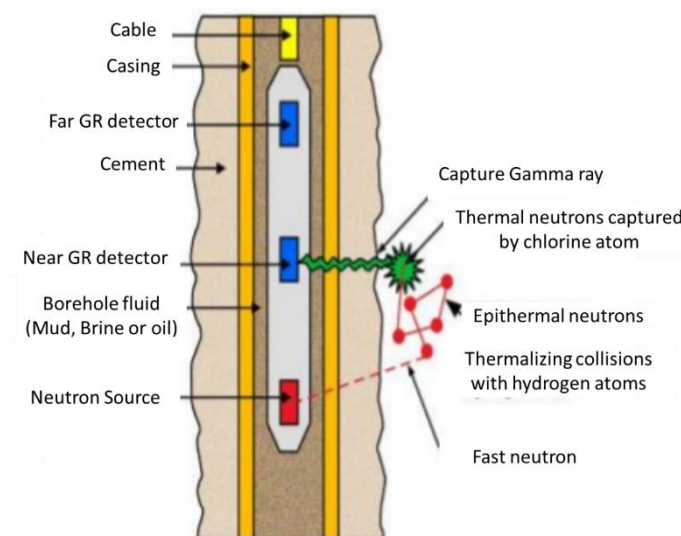


Figure 2.4: Schematic of PNC log (Kamboh, 2013).

2.1.5 Resistivity measurements

Resistivity measurement through open-hole logs is one of the oldest methods for differentiating between oil- and water-bearing zones (Archie, 1942). The working principle of resistivity logging is to simply induce an electrical current into the formation and measure the voltage. The resistivity is then computed

(Scholes and Johnston, 1993) and converted to saturation via Archie's equation. Oil-saturated rocks have high resistivity, whereas water-saturated rock have low resistivity (Darling, 2005; Figure 2.5). Open-hole resistivity logs are conducted once in the life of the well, directly after drilling; therefore, it can provide information regarding the saturation only at that time. However, in developed fields with dense drilling activities, open-hole resistivity logs can be applied in new wells, which aid in understanding the saturation distribution in the reservoir. Further development of this log has enabled the application in cased holes (Starcher et al., 2002; Dutta and Badr, 2008). This development allows for time-lapse measurements to compare the change in the resistivity profile with time and, therefore, to identify saturation changes. The depth of investigation of this log is limited to a maximum of three metres (Bond et al., 2010; Mazaheri et al., 2015; Mondol, 2015).

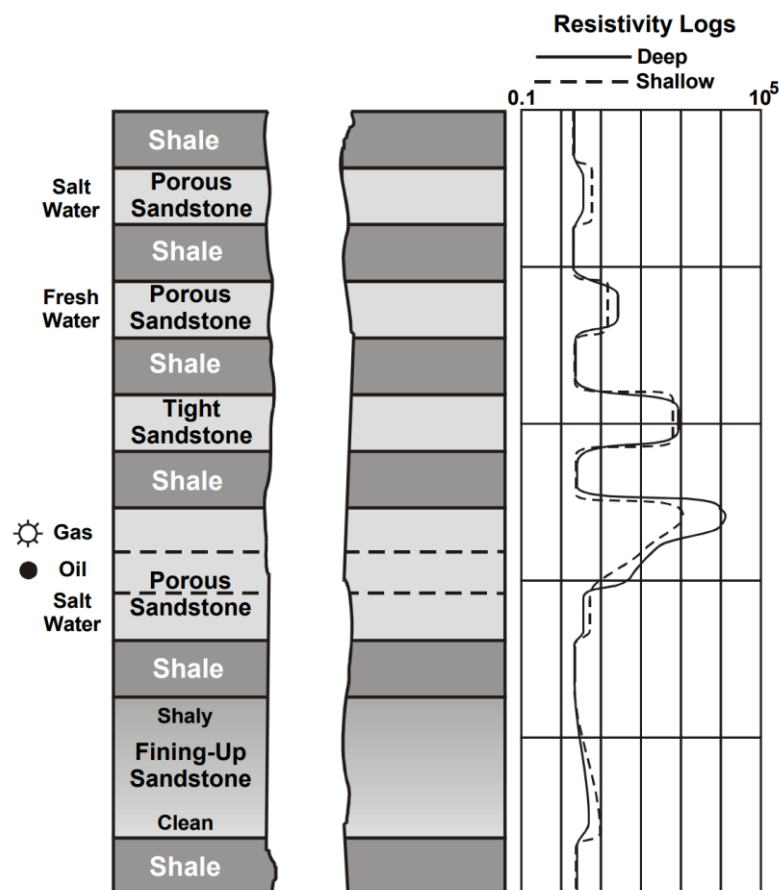


Figure 2.5: Example of a resistivity log (Glover, 2014).

Another technology that considers resistivity measurement is a downhole permanent electrode array that is installed at monitoring or production wells. The principle of this technology is based on injecting

a current in one downhole electrode and monitoring the voltage of the other downhole electrodes with respect to a reference electrode at the surface (Figure 2.6, Kleef et al., 2001; Charara et al., 2002; Bryant et al., 2004). Several researchers have conducted field trials and demonstrated a successful implementation of the electrode arrays (Bryant et al., 2001; Kleef et al., 2001; Charara et al., 2002; Bryant et al., 2004). However, there is uncertainty regarding the depth of investigation of this technology. Bryant et al. (2004) claimed a depth of investigation of 40 metres, whereas Charara et al. (2002) and Kleef et al. (2001) suggested several metres.

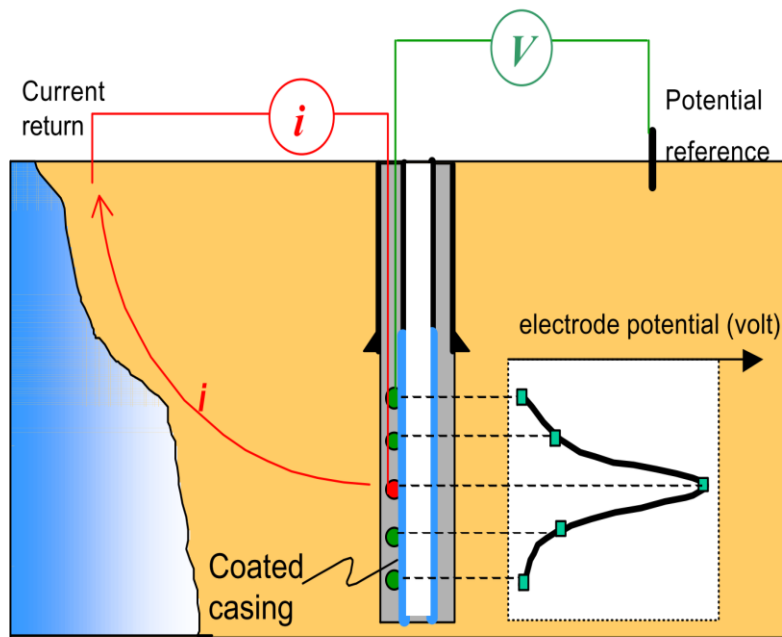


Figure 2.6: Principle of permanent resistivity array (Kleef et al., 2001).

2.1.6 Electromagnetic methods

Electromagnetic methods are based on the principle of using a transmitter to generate a primary electromagnetic field. This primary field penetrates through the formation and induces alternating (eddy) currents to flow within the conducting bodies. These currents generate a secondary electromagnetic field that interferes with the primary field (Figure 2.7). These fields (primary + secondary) are captured by a receiver that records the resultant of arriving primary and secondary fields. Therefore, the response of the resultant field (primary + secondary) differs from the response of the primary field. This difference between the transmitted and received electromagnetic fields reveals the

presence of a conducting body, such as a formation water, and provides information on its geometry and electrical properties (resistivity and, in turn, saturation; Halдар, 2016).

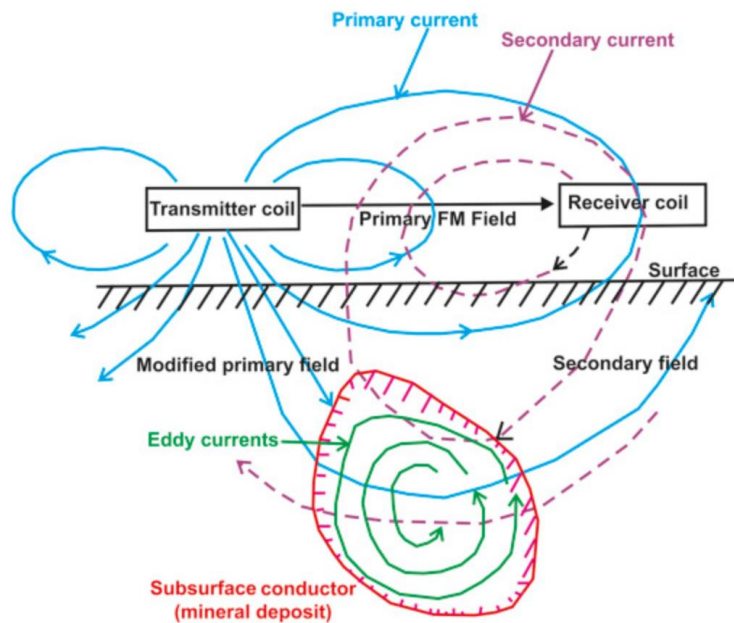


Figure 2.7: The principle of electromagnetic methods (Halдар, 2013).

The basic applications of the electromagnetic methods are the induction log and borehole radar, which are simple logs run using a tool that includes a transmitter and a receiver (Chen and Oristaglio, 2002; Wilt and Alumbaugh, 2003; Kaufman and Itskovich, 2017). The depth of investigation of these logs is limited to several metres into the formation (Chen and Oristaglio, 2002; Liu and Sato, 2002; Bond et al., 2010; Miorali et al., 2011; Mazaheri et al., 2015; Mondol, 2015). More advanced applications of electromagnetic methods include cross-well (Marsala et al., 2007; Wilt and Alumbaugh, 2003), borehole-to-surface (Aziz et al., 2011; Colombo et al., 2018) and surface-to-borehole (Marsala et al., 2011; Marsala et al., 2013) electromagnetic surveys. The differences between the surveys are due to the locations of the transmitters and receivers. In cross-well surveys, the transmitters and receivers are installed in two or more wells to investigate the area between them (Figure 2.8a). On the other hand, borehole-to-surface surveys require a transmitter to be installed in one well and arrays of receivers to be installed on the surface (Figure 2.8b). For surface-to-borehole surveys, transmitters are installed on the surface, while the receivers are installed in the well (Figure 2.8c). The depth of investigation of

these surveys is in the range of hundreds of metres (up to 1 km); however, the resolution is relatively low because of the low frequency used, up to 1000 Hz (Servin et al., 2019). Electromagnetic methods depend on time-lapse technique, which requires multiple runs over time to identify the saturation changes (Aziz et al., 2011), which is not always operationally preferable.

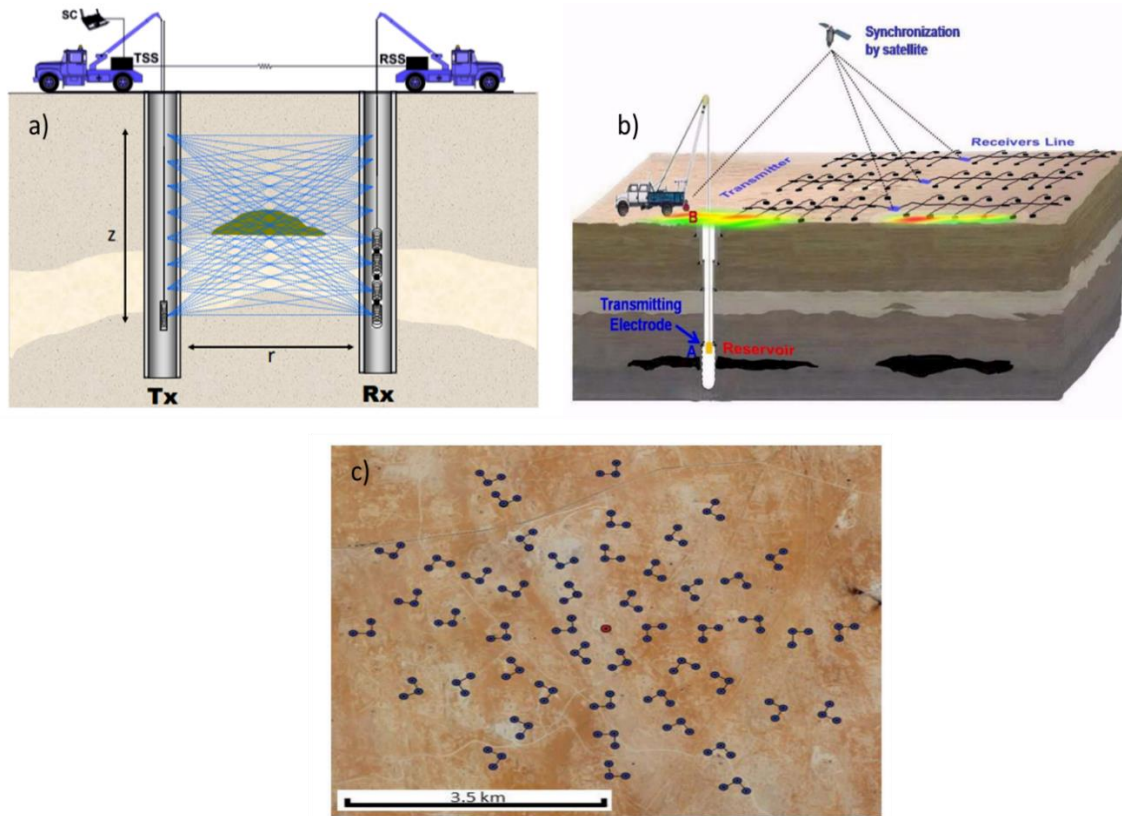


Figure 2.8: a) Cross-well (Biterge et al., 2014), b) borehole-to-surface (Marsala et al., 2011) and c) surface-to-borehole electromagnetic surveys (the red dot indicates the borehole surface location, and the blue dots represent the location of the surface transmitters; Colombo et al., 2018).

2.1.7 The self-potential method

Unlike the methods described in the previous sections, which are well developed monitoring techniques supported by several field implementation cases, the SP method has not been utilised in the oil industry heretofore. Nevertheless, on the basis of extensive modelling, several researchers have suggested this method as a promising technique for the early detection of water encroachment (Saunders et al., 2008; Gulamali et al., 2011; Jackson et al., 2012b; Ijioma, 2016). They asserted that it can detect water front movement from tens to hundreds of metres away from monitoring wells. They suggested that SP signals

could be recorded using electrically insulated electrodes installed downhole permanently at a monitoring well. These electrodes are the only component required to be deployed as this method does not require a current from a voltage source. The source of the signals for this method is the charge separation (current) that occurs naturally due to the difference in pressure, chemical composition and temperature between the formation water and encroaching water (Jackson, 2015). SP monitoring is the main focus of this research; therefore, the theory, origin, and applications of the method are describe in the following sections.

2.2 Overview of the Self-Potential Method

2.2.1 Origin of the self-potential

SPs are electrical potential differences that occur naturally as a response to charge separation caused by gradients in pressure (above hydrostatic; also termed water potential or head), chemical composition (salt concentration) or temperature (Jackson et al., 2012b). Charge separation occurs at the mineral-fluid interface in porous media. The mineral surface is electrically charged, which causes the formation of a boundary layer containing an excess of counter charge in the adjacent brine. This layer is known as the ‘electrical double layer’ (EDL) (Hunter, 1986; Jackson et al., 2012b). The EDL is composed of two sublayers, namely the Stern layer and the diffuse layer. The Stern layer holds non-mobile counter-ions, while the diffuse layer holds the mobile counter-ions. When a reservoir is subjected to a pressure gradient, the movable ions in the diffuse layer move with fluid, causing a charge separation. Furthermore, gradients in temperature and ionic concentrations in the brine lead to ion migration. However, ions do not migrate at the same rate because of the differing mobilities, which results in charge separation. For instance, the mobility of sodium ions is about 70% that of chloride ions (Braun and Weingärtner, 1985). Separation of charge due to the above mentioned factors creates an electrical current which is balanced naturally by a conduction current to maintain the overall electroneutrality. The electrical potential required to establish the conduction current is referred to as SP (Revil et al., 1999a). The overall SP is comprised of three components: the electrokinetic potential (EK), the

electrochemical (EC) or exclusion-diffusion potential (ED) and the thermoelectrical potential (TE) which are related to the gradients in pressure, concentration and temperature, respectively.

2.2.1.1 Electrokinetic potential

Gradients in water potential cause water and other fluids to flow through the rock. Water drags with it an excess of electrical charge in the EDL adjacent to the mineral surfaces, establishing a current termed the ‘streaming current’ (Hunter, 1986; Jackson et al., 2012b; Figure 2.9a). A conduction current is naturally established to globally balance the streaming current to ensure overall electroneutrality. The streaming current might not follow the same pathways as the conduction current, so they might not balance locally. From Ohm’s Law, it is well known that a conduction current must be driven by an electrical potential difference; this potential difference is termed the ‘electrokinetic’ (EK) or ‘streaming’ potential and is the part of the SP that arises from gradients in water potential (Ishido and Mizutani, 1981; Revil et al., 1999a).

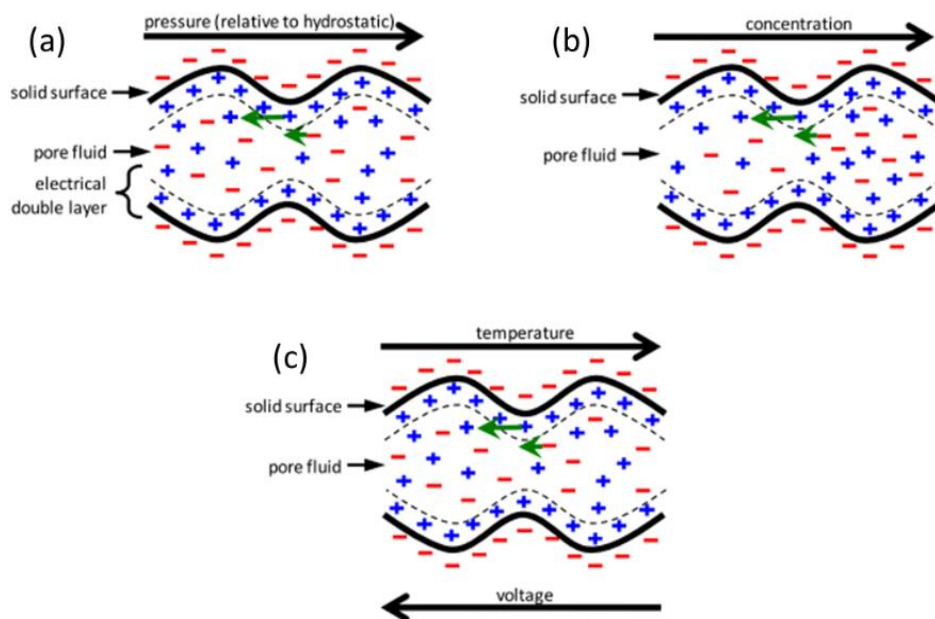


Figure 2.9: Representation of charge separation due to (a) pressure, (b) concentration and (c) temperature gradients. Herein, the EDL is denoted simply by the dashed line and contains an excess of positive charge that balances the negative charge on the mineral surfaces (Jackson et al., 2012b). Ion transport is denoted by arrows.

A major factor in controlling the generated EK potential is the EK coupling coefficient, which can be defined as the ratio of the fluid potential gradient (∇P) to the EK potential gradient (∇V) when the total current density (j) is zero (Sill, 1983).

$$C_{EK} = \frac{\Delta V}{\Delta P} \quad (2.1)$$

A number of experimental and theoretical studies have characterised the EK coupling coefficients for sandstones (e.g. Revil and Cerepi, 2004; Jaafar et al., 2009; Vinogradov et al., 2010; Glover et al., 2012; Walker et al., 2014; Vinogradov and Jackson, 2015; Esmaeili et al., 2016; Vinogradov et al., 2018; Walker and Glover, 2018; Glover, 2018; Li et al., 2018) and carbonates (e.g. Jackson and Vinogradov, 2012; Chen et al., 2014; Alroudhani et al., 2016; Jackson et al., 2016; Al Mahrouqi et al., 2017; Ghommam et al., 2018; Collini et al., 2020). Herein, we focus on sandstones because this focus is relevant to the Greater Burgan reservoir investigated in this study. Most of the published EK coupling coefficient data for sandstones were obtained for fully-saturated ($S_w = 1$) conditions with low salinity (< 0.5 M/L) simple monovalent NaCl brines at laboratory temperature. These published data suggested that the EK coupling coefficient decreases with increasing brine salinity. Jaafar et al. (2009), Vinogradov et al. (2010), Walker et al. (2014) and Walker and Glover (2018) measured the EK coupling coefficients at higher salinities (up to 5.5 M/L) for sandstone samples saturated with NaCl brines. Their results at low salinity (less than 0.4 M/L) were consistent with previous results. At high salinity, they noted that the magnitude of the EK coupling coefficient also decreased with increasing the salinity and was still measurable up to the saturated brine salinity in laboratory conditions (Figure 2.10a).

The EK coupling coefficient is related to the zeta potential, which is the measure of the electrical potential at the mineral surface, through the modified Helmholtz-Smoluchowski equation as follows (Jouniaux and Pozzi, 1995; Glover, 2015)

$$C_{ek} = \frac{\Delta V}{\Delta P} = \frac{\varepsilon_w \zeta}{\mu_w \sigma_r F} \quad (2.2)$$

where ζ is the zeta potential, ε_w is the permittivity, μ_w is the brine dynamic viscosity, σ_r is the saturated rock electrical conductivity and F is the formation factor, which is the ratio of the brine electrical

conductivity to the saturated rock electrical conductivity. The magnitude and polarity of the zeta potential control the electrostatic forces between the mineral surface and polar species in the adjacent fluids (Hunter, 1986). Experimental measurements of the zeta potential on intact sandstone samples involve: first, measurements of the EK coupling coefficient and second, using equation (2.2) to obtain the zeta potential. The zeta potential of water-saturated sandstones has been studied by several researchers and it is widely accepted that the polarity of the sandstone zeta potential is negative (the EK coupling coefficient as well) and decreases in magnitude with increasing salinity when saturated with NaCl brines (Figure 2.10b; Pride and Morgan, 1991; Revil et al., 1999a; Kirby and Hasselbrink Jr, 2004; Glover et al., 2006; Boleve et al., 2007; Alkafef and Alajmi, 2006; Jaafar et al., 2009; Vinogradov et al., 2010; Walker et al., 2014; Walker and Glover, 2018). This trend is consistent with the predictions of the EDL models based on the Poisson-Boltzmann equation (Hunter, 1986; Revil et al., 1999a). However, at high salinities ($> \sim 0.4$ M/L), it has been observed that the zeta potential is constant and independent of salinity (Jaafar et al., 2009; Vinogradov et al., 2010; Walker and Glover, 2018). At high salinity, the Poisson-Boltzmann equation predicts that the thickness of the diffuse layer reaches zero and consequently, the zeta potential falls to zero. Jaafar et al. (2009) hypothesised that the thickness reduction of the diffuse layer at high salinity is less than that predicted by the Poisson-Boltzmann equation. Additionally, the counter ions required to balance the charge in the rock surface are not entirely located in the Stern layer, which implies that the diffuse layer does not fall to zero. The thickness of the diffuse layer is limited by the size of the hydrated counter ions at maximum charge density and some of the counter ions within it remain mobile, which gives rise to an EK current.

The limited available data suggest that the EK coupling coefficient and zeta potential for complex natural brines are smaller in magnitude for a given ionic strength compared to the values in monovalent brines as shown in Figures 2.10c, d, e and f (Vinogradov et al., 2018; Li et al., 2018). The temperature dependence of the EK coupling coefficient and zeta potential was also studied, and it was found that they were approximately independent of temperature over the range of 20°C–120°C in brines of moderate to high ionic strength (Reppert and Morgan, 2003a, 2003b; Vinogradov and Jackson, 2015;

Vinogradov et al., 2018). However, at low salinity (< 0.45 M/L), the zeta potential was found to decrease in magnitude with increasing temperature.

All the studies discussed earlier were conducted on fully saturated conditions ($S_w = 1$). However, in many subsurface settings, such as oil and gas reservoirs and unconfined aquifers, the reservoir rocks are partially saturated with water. It is thus vital to understand the relation between the EK coupling coefficient and water saturation. A number of researchers have measured the relationship between coupling coefficient and water saturation in sandstone and carbonate rocks (Guichet et al., 2003; Revil and Cerepi, 2004; Linde et al., 2007; Revil et al., 2007; Vinogradov and Jackson, 2011). Guichet et al. (2003), Revil and Cerepi (2004) and Revil et al. (2007) measured the EK coupling coefficient during drainage experiments in which a non-wetting gas (argon or nitrogen) invaded initially brine-saturated sandpacks and carbonate samples. They reported a decrease in the EK coupling coefficient with decreasing water saturation reaching a value of zero at irreducible water saturation ($S_w = S_{wirr}$). Likewise, Moore et al. (2004) and Vinogradov and Jackson (2011) reported a decreasing trend of the EK coupling coefficient with saturation during drainage in which the invading non-wetting phase was liquid CO₂ and undecane. However, they measured a non-zero coupling coefficient at irreducible water saturation. Vinogradov and Jackson (2011) explained that it was because of the water flow within the wetting layers, caused by the hydraulic coupling between the wetting and the non-wetting phases. Although the volume of the moving water was small, it was rich in charge, giving rise to a streaming current and hence, a non-zero coupling coefficient. On the other hand, they explained that the zero EK coupling coefficient at irreducible water saturation for gas/water experiments was because of the small hydraulic coupling between the water and gas under the used pressure differences.

Vinogradov and Jackson (2011) also measured the EK coupling coefficient during imbibition experiments. They noted that the coupling coefficient measured at residual oil saturation ($S_w = 1 - S_{or}$) in water/undecane displacements exceeded the value measured in fully saturated conditions, while it remained below that value for gas/water displacements. They hypothesised that this difference in the trend was because of the excess charge in the EDL at the undecane-water interface.

In addition to these experimental efforts, a number of theoretical models concerned with the saturation dependence of the EK coupling coefficient have been published and compared with the available experimental data (Figure 2.10j; Wurmstich and Morgan, 1994; Perrier and Morat, 2000; Linde et al., 2007; Jackson, 2010; Gulamali et al., 2012; Allègre et al., 2012; Jougnot et al., 2012; Jackson et al., 2012a; Zhang et al., 2017; Soldi et al., 2019; Vinogradov et al., 2021).

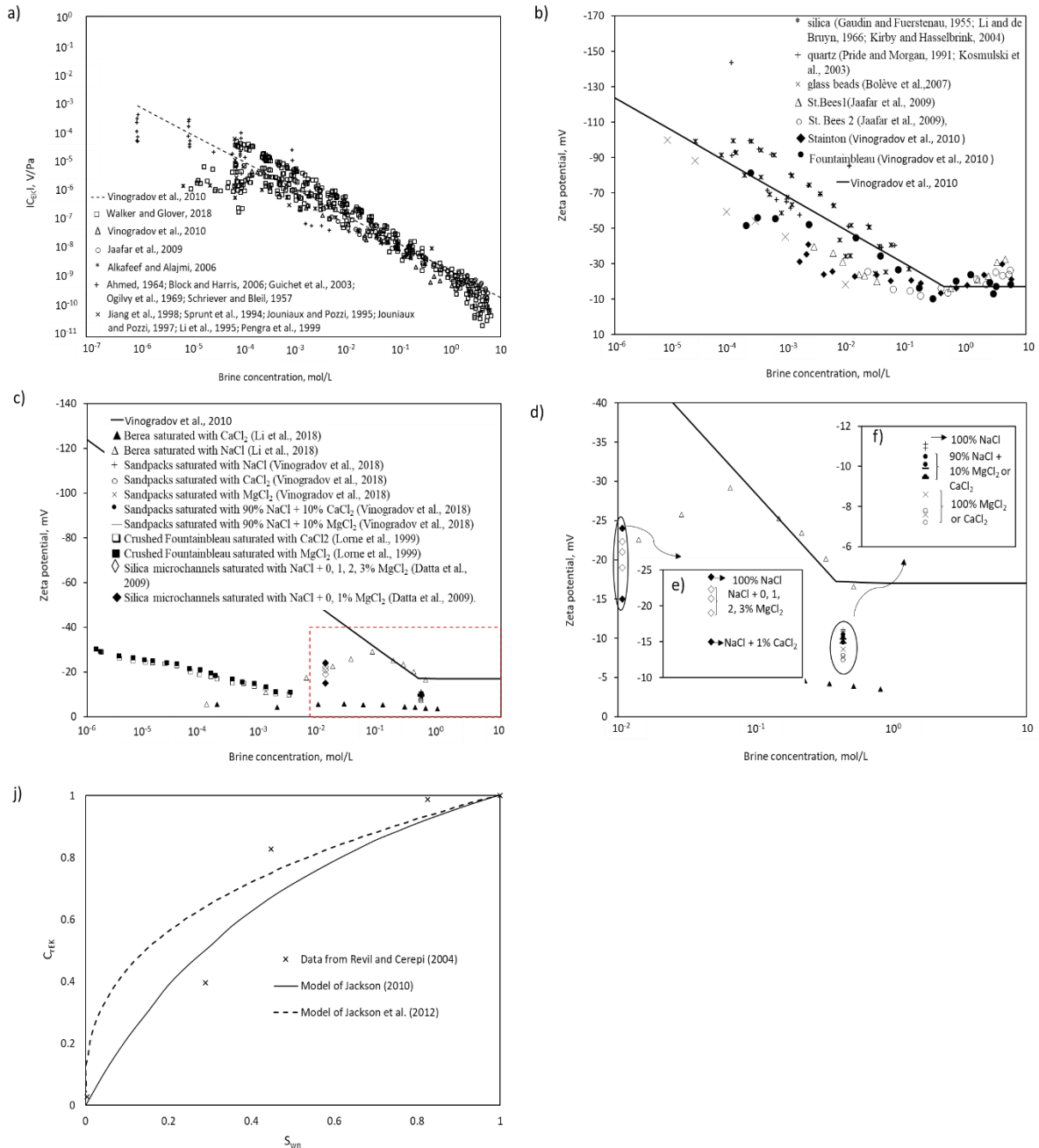


Figure 2.10: a) EK coupling coefficient versus brine concentration from published data. The solid line represents a regression fitted by Vinogradov et al. (2010). b) Zeta potential versus brine concentration from published data that used simple NaCl brines. The solid line represents a regression fitted by

Vinogradov et al. (2010). c) Zeta potential versus brine concentration from published data that used brines containing divalent ions. The solid line represents a regression fitted by Vinogradov et al. (2010). d) The same data as (c), but focused on the high salinity region of interest [(red box in (c))]. e) and f) The same data as (c) but focused on two specific datasets of interest. j) Relative EK coupling coefficient versus normalised water saturation.

In summary, most of the EK coupling coefficient measurements on sandstones were conducted with pure or close-to-pure quartz outcrop samples fully saturated with simple monovalent NaCl brines. However, natural sandstones found in the subsurface usually have a more complex mineralogy that could include different types of clays, carbonates and other mineral species, in contact with complex brines containing multiple ionic species. The impact of complex mineral properties and divalent cations has been shown to change the electrostatic behaviour from these widely accepted trends due to mineral-fluid interactions such as ion exchange, dissolution and precipitation (Li et al., 2018). Therefore, it is very important to perform the measurements using representative reservoir rock samples and brines, which was not considered in most of the previous studies concerned with the topic in question. Moreover, the limited experimental measurements of the EK coupling coefficient at partial saturation imply that the behaviour is still uncertain and requires further investigation.

2.2.1.2 Exclusion-diffusion potential

The water (brine) found in subsurface reservoirs contains dissolved, dissociated salt species. Gradients in salt species concentration cause ion transport by diffusion. However, the salt ions do not migrate at the same rate, which causes an electrical charge separation that is countered by an electrical potential termed the ‘diffusion potential’. If there is a concentration gradient across a rock with a very small pore size, then the electrical charge on the mineral surfaces could prevent ions of the same polarity from entering the pores; only ions with an opposing polarity can migrate down the concentration gradient, which would give rise to an electrical potential termed the ‘exclusion potential’. Together, these two sources of SP are termed the ‘exclusion-diffusion’ (ED) or ‘electrochemical’ (EC) potential; this is the part of the SP that arises from concentration gradients (Revil, 1999; Jackson et al., 2012b; Figure 2.9b). Accordingly, two end member cases can be defined when either the pure diffusion or pure exclusion potential dominates. The relative contribution of the exclusion and diffusion components of the ED can

be defined by a dimensionless number termed the ‘exclusion efficiency’ (ε_{ED}). An exclusion efficiency of unity corresponds to an exclusion-dominated ED potential, while an efficiency of zero corresponds to a diffusion-dominated ED potential (Leinov and Jackson, 2014).

Studies targeting measurements of the ED coupling coefficient are not as widely available in the literature as those reporting measurements of the EK coupling coefficient. Early efforts to measure ED coupling coefficients were limited with respect to the concentration ranges considered and the reporting of the methodology deployed (Hill and Milburn, 1956; Nourbehect, 1963; Smits, 1968; Ortiz et al., 1973; Thomas, 1976). More recently, a number of researchers reported an improved experimental methodology (Revil et al., 2005; Jougnot and Linde, 2013; Leinov and Jackson, 2014; MacAllister et al., 2019). Leinov and Jackson (2014) reported ED coupling coefficients in sandstone core samples saturated with NaCl brine over a range of temperatures and concentrations. They found that diffusion potential dominated when the pore radius was more than 4000 times larger than the diffuse layer thickness (equivalent to very fine-grained sandstone saturated with relatively high salinity brine). Leinov and Jackson (2014) observed that the potential was diffusion dominated ($\varepsilon_{ED} = 0$) at a low concentration ratio (less than 100), while the observed ED potential diverged from the diffusion-dominated limit towards the exclusion-dominated limit ($0 < \varepsilon_{ED} < 0.2$; Figure 2.11a) at a high concentration ratio. Leinov and Jackson (2014) suggested that the relative contribution of diffusion and exclusion potentials (exclusion efficiency) to the overall ED potential was related to the ratio of the pore throat radius (r) to the thickness of the EDL (L), consistent with the modelling work done by Westermann-Clark and Christoforou (1986). If r/L is small, the EDL occupies a significant portion of the pore space and the electrostatic repulsive forces exclude ions of the same charge as the mineral surface, usually considered to be negative for most sandstones and shales (Vinogradov et al. 2010; Walker and Glover, 2018). Conversely, when r/L is large, the EDL is small relative to the pore radius, so the surface charge is confined to the mineral surface and there is little or no charge exclusion and the diffusion potential therefore dominates. MacAllister et al. (2019) measured values of $\varepsilon_{ED} = 0 - 0.1$ and $\varepsilon_{ED} = 0.3 - 0.4$ for carbonates and shales, respectively under fully saturated conditions with natural groundwater and seawater (Figure 2.11a).

In partially-saturated conditions, only one study (Ortiz et al., 1973) was concerned with the ED potential with hydrocarbon saturation (paraffin) during drainage (Figure 2.11b). Ortiz et al. (1973) suggested that, at low water saturation, the excess charge is confined to thin water films and small, water-occupied pores from which co-charge is efficiently excluded. Thus, the ED potential is dominated by exclusion ($\epsilon_{ED} = 1$). Conversely, at high water saturation, the water occupies most of the pores and the ED potential is dominated by diffusion. On the basis of these findings, Jackson et al. (2012) and Gulamali et al. (2011) developed two models to predict the saturation dependence of the ED coupling coefficient.

In summary, there is a dearth of meaningful experimental data or numerical models investigating and quantifying the ED potentials in fully and partially saturated conditions.

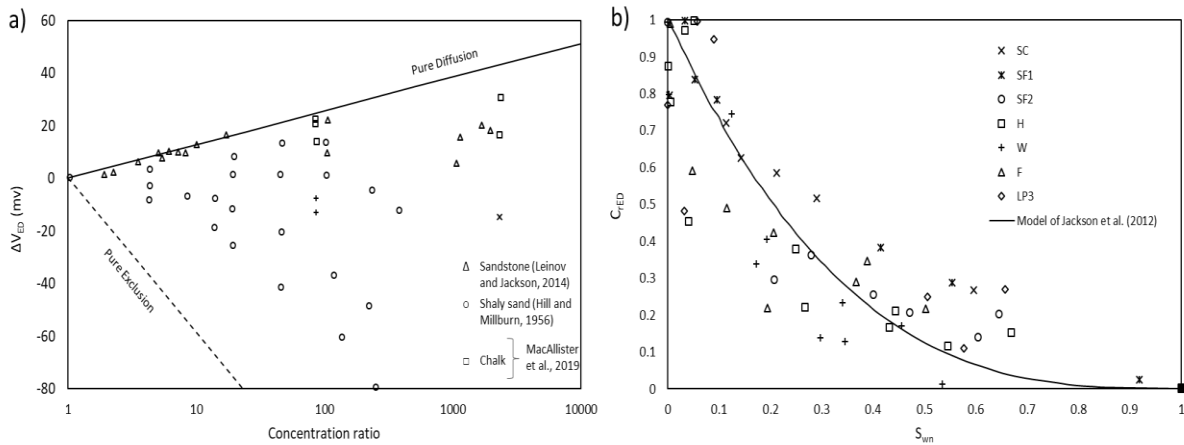


Figure 2.11: a) ED potential versus concentration ratio. The solid line represents the diffusion-dominated ED potential and the dashed line represents the exclusion-dominated ED potential. b) Relative ED coupling coefficient versus normalised water saturation. The symbol labels refer to the sample descriptions reported by Ortiz et al. (1973).

2.2.1.3 Thermoelectrical potential

Gradients in temperature also cause ion transport by diffusion, and the resulting electrical charge separation is countered by an electrical potential termed the ‘thermoelectric’ (TE) potential; this is the part of the SP that arises from temperature gradients (Jackson et al., 2012b). TE potential has a similar origin to the ED potential, except that the ion diffusion is due to temperature gradient; therefore, it is also limited by the two end members: pure diffusion and pure exclusion. The relative contribution of the diffusion and exclusion potentials can be described by a dimensionless number termed ‘exclusion

efficiency' (ϵ_{TE}), which is limited between zero (diffusion-dominated) and one (exclusion-dominated) (Leinov and Jackson, 2014). Early studies (Marshall and Madden, 1959; Nourbehect, 1963; Dorfman et al., 1977; Fitterman and Corwin, 1982; Zlotnicki and Nishida, 2003; Revil et al., 2013) on the measurement of TE coupling coefficients provided a limited description of the experimental conditions and methodology, while recent ones (Rosanne et al., 2006; Leinov et al., 2010; Leinov and Jackson, 2014; Ikard and Revil, 2014; Revil et al., 2016) are more informative in terms of the description of experimental setups, samples, conditions and results.

In fully saturated conditions ($S_w = 1$), experimental measurements on sandstone samples, exhibit diffusion-dominated behaviour when the core is saturated with higher salinities (> 0.01 M/L), and it becomes more exclusive with lower salinities (Figure 2.12; Leinov and Jackson, 2014). At present, there is no published experimental data on the relation between TE potential and saturation. However, there are some models presented by Jackson et al. (2012b) and Gulamali et al. (2011) based on the conclusions proposed by Ortiz et al. (1973) regarding the saturation dependence of ED potential.

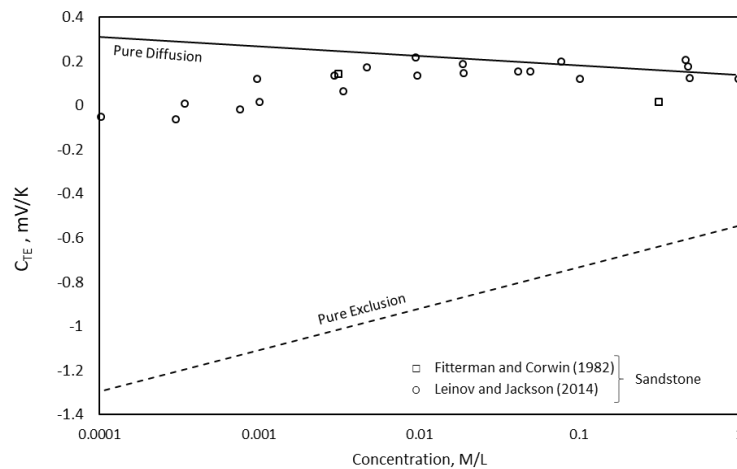


Figure 2.12: a) TE coupling coefficient versus brine concentration. The solid line represents the diffusion-dominated TE potential and the dashed line represents the exclusion-dominated TE potential.

2.2.2 Self-potential monitoring in oil reservoirs

Measurement of the SP is one of the oldest geophysical surveying methods with numerous applications (Jackson, 2015). A plethora of researchers have investigated the SP associated with water flow in

geothermal reservoirs (e.g., Corwin and Hoover, 1979; Revil and Pezard, 1998; Darnet et al., 2004) and during volcanic unrest (e.g., Zlotnicki and Nishida, 2003; Ishido, 2004; Finizola et al., 2004; Mauri et al., 2010; Grobbe and Brade-Cabusson, 2019); groundwater flow in aquifers (e.g., Fagerlund and Heinson, 2003; Titov et al., 2005; Linde et al., 2011; Jackson et al., 2012a; Hu et al., 2020); contaminant transport in aquifers (e.g., Naudet et al., 2003, 2004; Minsley et al., 2007; Linde and Revil, 2007; Jougnot et al., 2015); saltwater intrusion in coastal aquifers (MacAllister et al., 2018; Graham et al., 2018) and water flow during hydrocarbon production (Saunders et al., 2008; Gulamali et al., 2011; Jackson et al., 2012b; Ijioma, 2016). However, the prediction and interpretation of the SP in these environments are challenging because there could be several source mechanisms. Moreover, the flow and transport paths might be complicated by geological heterogeneity.

In the oil industry, SP logging using wireline tools in open-hole wells is a common method for characterising reservoirs in terms of identifying permeable beds and formation water resistivity. The signals measured during logging are dominated by the ED potential, which originates from the difference in composition between the formation and drilling fluids and the exclusion of negative ions from the pores of shales and mudstones (Mounce and Rust Jr, 1944; Doll, 1949; Hallenborg, 1971). However, SP signals are also generated during production with the availability of an active aquifer or water flooding due to gradients in pressure, temperature and composition. Continuous recording of these signals could be interpreted to track saturation changes within the reservoir. The first study to suggest the utilisation of SP for monitoring hydrocarbon reservoirs was conducted by Wurmstich and Morgan (1994). They considered a single-phase problem and a low production rate of 500 bbl/d for their modelling. Their conclusions were not promising because the predicted EK potential signals were too small to resolve. Moreover, they did not consider monitoring at the production well because they assumed that the conductive casing string would affect the readings. Assuming that monitoring would occur at a production well, Worthington et al. (2002) presented more promising results.

More recently, numerical modelling work considering sandstone reservoirs showed that the EK potential is maximised at the waterfront and at geological boundaries where water saturation changes, and decays with distance. As water approaches a production well, the generated EK potential is expected

to encompass the well when the front is up to 100 metres away; at that point, the SP at the well starts to respond significantly (Figure 2.13a and b; Saunders et al., 2006, 2008; Gulamali et al., 2011; Jackson et al., 2012b). Sensitivity-based studies that were conducted by varying the temperature, water salinity, water to oil viscosity ratio, production and geological scenarios and well geometries have provided a solid understanding of the behaviour of the EK potential during oil production (Saunders et al., 2008, 2012; Jackson et al., 2012b, Ijioma, 2016).

ED and TE potentials were modelled by Gulamali et al. (2011) and Jackson et al. (2012b) in sandstone reservoirs. The resulted ED potential peaked at the trailing edge of the salinity front and decreased to zero ahead of the leading edge (Figure 2.13a). A similar behaviour was observed for the TE potential (Figure 2.13a). At a monitoring well, the EK and ED signals were observed to dominate the measured SP, while the TE signal was negligible. The small TE signal was due to the lag of the temperature front behind the saturation and salinity fronts (Figure 2.13a). Typical results of the three SP components obtained by Jackson et al. (2012b) are shown in Figure 2.13. The SP signal measured along the vertical profile at the well increased as the waterfront got closer to the well and the shape of the vertical profile across the well reflected the shape of the encroaching waterfront (Figure 2.14). Given these encouraging results, Ijioma (2016) suggested implementing downhole SP measurements for proactive feedback control strategies in smart wells. For example, water production could be delayed or prevented by closing production from the offending layer using inflow control valves.

The SP in the above-mentioned studies was assumed to be measured between an installed downhole electrode array and a reference electrode at infinity. In reality, the reference electrode can be placed downhole but away from the reservoir (for example, above the seal lithology). Practically, only Chen et al. (2006) presented continuous measurements of SP during production of an oil field. Stable electrode signals above 0.01 mV were observed, with some noise spikes on the order of 0.1 mV due to the connection quality from surface to downhole. Based on that, they suggested that signal magnitude of the order of 0.1 mV could be reliably measured. Cumella et al. (2017) suggested that the SP, obtained during open-hole logging in a low permeability gas field during production, was dominated by the electrokinetic component of the SP, which they interpreted to arise from the flow of brine in response

to gas production. However, the approach of Cumella et al. (2017) was based on open-hole SP logs in new and observation wells, while the approach presented by Chen et al. (2006) can be used for continuous in-well SP monitoring.

One of the crucial uncertainties in these studies is the value of the SP coupling coefficients. Recent experimental work discussed in the previous sections contributed considerably to the overall understanding of the nature of these coefficients. However, additional experimental work is essential for a more in-depth understanding, especially experiments that account for different rock types and mimicking real field conditions. Moreover, all the modelling and experimental studies discussed earlier were conducted for sandstone reservoirs and sandstone core samples. Less experimental work has been conducted for carbonate samples (see Al-Mahrouqi (2016)), while no numerical modelling work has yet been done on carbonate reservoirs.

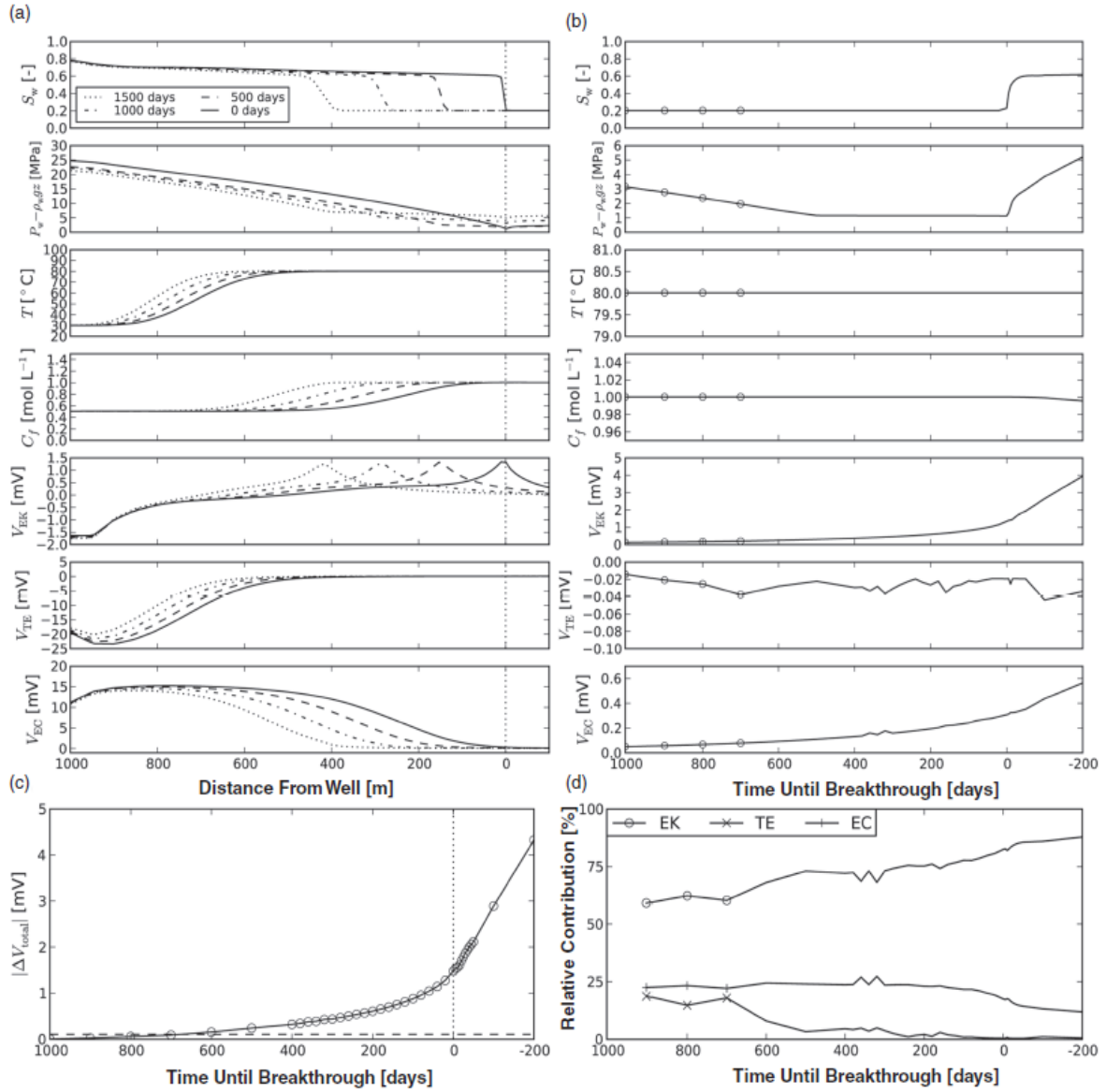


Figure 2.13: Numerical modelling results presented by Jackson et al. (2012). a) Panels (from top to bottom) display water saturation, water potential, temperature, salinity, EK, ED and TE potentials as a function of distance from the production well (marked with a dashed line). b) Panels (from top to bottom) show water saturation, water potential, temperature, salinity, EK potential, ED potential and TE potential as a function of time until water breakthrough, recorded at the centre of borehole. c) Magnitude of the change in the overall SP relative to the SP 1000 days before the breakthrough as a function of time until water breakthrough, recorded at the centre of the borehole. The horizontal dash line represents a likely downhole noise of 0.1 mV. d) Relative contribution of EK, ED and TE potentials to the overall SP signal as a function of time until water breakthrough, recorded at the centre of the well (Jackson et al., 2012b).

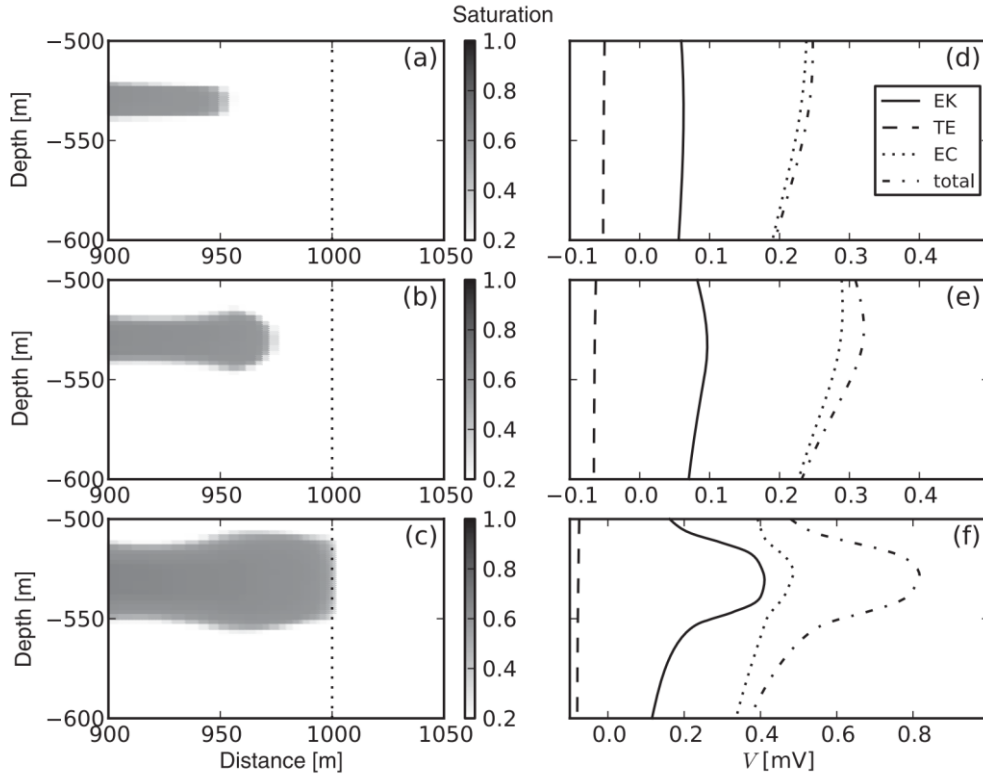


Figure 2.14: Vertical cross-sections showing water saturation when waterfront is (a) 50 m away from a production well, (b) 25 m away from a well and (c) at breakthrough. The vertical dashed line represents well location. Plots (d) to (f) show the corresponding EK, TE and ED components of the SP signal measured at a production well (Jackson et al., 2012b).

2.3 Summary

This chapter comprised an overview of the current available geophysical monitoring techniques for hydrocarbon reservoirs, with their advantages and limitations. With reference to this review, SP monitoring has been proposed as a new encouraging monitoring technique to detect water movement. In hydrocarbon reservoirs, the SP is generated to maintain overall electrical neutrality when separation of charges occurs because of gradients in water potential, temperature and chemical composition during waterflooding or aquifer influx.

A great deal of work has been done to model the predicted SP signals in synthetic hydrocarbon reservoirs, which resulted in the development of a solid understanding of the behaviour of SP during hydrocarbon production. The magnitude and the behaviour of SP were found to be dependent on a combination of reservoir and production parameters, including production rate, permeability,

heterogeneity, geology, fluid properties and coupling coefficients (Jackson et al., 2012b). This modelling work was supported by experimental work measuring the SP coupling coefficients. However, most of the experimental work was conducted with pure or close-to-pure quartz samples collected from outcrops and saturated with simple NaCl brines. In hydrocarbon reservoirs, this is not the case; the reservoir rocks have a more complex mineralogy, and the brine is composed of multiple ionic species. Therefore, there are major uncertainties related to the applicability of this technology when it comes to actual hydrocarbon reservoirs. Thus, the main motivation for this work is to assess the feasibility of this promising technology in a real case reservoir and to identify the potential benefits and limitations associated with it. This feasibility assessment can help to address the uncertainties with regard to the behaviour of SP in complex environments and the magnitude and polarity of the coupling coefficients of natural rocks at full or partial saturation.

Chapter 3

Numerical Modelling of Self-Potential

3.1 Introduction

Measurement of the SP is one of the oldest geophysical surveying methods with numerous applications (Jackson, 2015). Herein, we focus on the use of SP to characterise and monitor water flow and the associated transport of salt species and/or heat in subsurface reservoirs. As discussed in Section 2.2.2, SP monitoring has tremendous potential as a useful monitoring technique for a number of applications (e.g., geothermal reservoirs, volcanic activities, groundwater and contaminant flow in aquifers, saltwater intrusion in coastal aquifers and water flow in hydrocarbon reservoirs). However, prediction or interpretation of the SP in these reservoirs is challenging as there may be several source mechanisms; moreover, flow and transport paths may be complicated by geological heterogeneity.

This chapter reports a new, open-source, MATLAB-based 3D code for numerically simulating the SP in subsurface reservoirs. Although this research is focused on SP in hydrocarbon reservoir, the said code was developed as a general tool to simulate SP in other geophysical applications. This code works as a post-processor, taking outputs from existing reservoir flow and transport simulators at a selected timestep, and calculating the SP throughout the reservoir model using the simulated values of water saturation, pressure, concentration and temperature. The additional material parameters required to calculate the SP are defined by the user and may be constant or variable for each cell. Earlier versions of this code have been used in previous studies concerning saline intrusion into freshwater aquifers (MacAllister et al., 2018; Graham et al., 2018), and oil production from hydrocarbon reservoirs (Ijioma, 2016). Additional functionality included in the new version of the code allows local grid refinement, simulation of SP in models of faulted reservoirs and modelling heterogeneity in the coupling coefficients.

The code solves the equations governing flow and transport of electrical charge and global charge conservation using a control-volume-finite-difference scheme. Electrical currents associated with the

SP may spread beyond the reservoir model domain, and the code allows for the domain to be extended vertically and laterally to account for this. The code can be used for predicting the SP in a given reservoir, which is useful for (i) designing and implementing SP monitoring programmes, (ii) interpreting SP measurements from existing monitoring programmes, and (iii) understanding SP source mechanisms and the link between source mechanisms and flow and transport processes in the reservoir. The code can be used in a broad range of subsurface reservoir types including aquifers, geothermal reservoirs, targets for CO₂ storage and hydrocarbon reservoirs. We present the governing equations and the numerical methods used to solve these and show that the code returns the correct solution for some simple test cases. We demonstrate application of the code using an example in which we predict the SP signals associated with oil production from a subsurface reservoir supported by water injection.

3.2 Governing Equations

As discussed in Section 2.2, this study is focused on three main components of SP arising in partially or entirely water-saturated rocks in response to gradients in pressure (above hydrostatic, also termed water potential or head), water composition (salt concentration) and temperature. Therefore, assuming that water is the only charge-carrying fluid in the rock pore space, the general form of the constitutive equations used to describe the coupled problem can be written as (De Groot and Mazur, 1962)

$$\begin{pmatrix} j \\ q_w \\ h \\ v \end{pmatrix} = - \begin{bmatrix} \sigma_{fs}(S_w) & L_{EK} & L_{TE} & L_{ED} \\ L_{EK} & \frac{kk_{rw}(S_w)}{\mu_w} & A_1 & A_2 \\ L_{TE} & A_1 & K(S_w) & A_3 \\ L_{ED} & A_2 & A_3 & D(S_w) \end{bmatrix} \begin{bmatrix} \nabla U \\ \nabla \Phi \\ \nabla T \\ \nabla C_f \end{bmatrix} \quad (3.1)$$

where j is the current density ($A \cdot m^{-2}$), σ_{fs} is the saturated rock electrical conductivity ($S \cdot m^{-1}$), S_w is the water saturation, ∇U is the electrical potential gradient ($V \cdot m^{-1}$), q_w is the water Darcy velocity ($m \cdot s^{-1}$), k is the rock absolute permeability (m^2), k_{rw} is the relative permeability of water (fraction), μ_w is the dynamic viscosity of water ($Pa \cdot s$), $\nabla \Phi$ is the pressure gradient above hydrostatic (or water potential in $Pa \cdot m^{-1}$), where $\Phi = P_w - \rho_w g z$, h is the heat flux ($W \cdot m^{-2}$), K is thermal conductivity ($W \cdot m^{-1} \cdot K^{-1}$), ∇T

is the temperature gradient ($\text{K}\cdot\text{m}^{-1}$), v is the concentration flux ($\text{M}\cdot\text{s}^{-1}\cdot\text{m}^{-2}$), D is the diffusion coefficient ($\text{m}^2\cdot\text{s}^{-1}$) and ∇C_f is the concentration gradient ($\text{M}\cdot\text{m}^{-1}$).

The on-diagonal terms in equation (3.1) appear in the well-known constitutive equations of Ohm's law, Darcy's law, Fourier's law and Fick's law, respectively. The matrix is symmetric in linear thermodynamic systems in which fluxes are linear functions of thermodynamic forces ($\nabla U, \nabla \Phi, \nabla T$ and ∇C_f) (De Groot and Mazur, 1962). The off-diagonal terms L_{EK} , L_{ED} and L_{TE} are the EK, ED and TE cross-coupling terms, respectively. These terms describe the cross-coupling between electrical current and gradients in water potential, concentration, and temperature. The off-diagonal terms A_1 through A_3 represent cross-coupling terms governing the interactions between fluxes and gradients in electrical potential, water potential, temperature and concentration that are not considered here.

The water flux, heat flux and ion species flux can be calculated using existing commercial and academic reservoir flow and transport simulators such as ECLIPSE (Schlumberger, 2010), TOUGH2 (Pruess et al., 1999), IC-FERST (e.g. Gomes et al., 2016), the MATLAB Reservoir Simulation Toolkit (MRST; Lie, 2019), SUTRA3D (Voss and Provost, 2002) and many others. These simulators neglect the cross-coupling terms L because their impact on the calculated fluxes is negligible in the reservoirs of interest (Ishido and Mizutani, 1981; Wurmstich and Morgan, 1994; Revil et al., 1999b; Saunders et al., 2008). Given this, we can solve for the electrical current independently from the flux calculations in a 'post-processing' step, given the water potential, temperature and concentration fields obtained from reservoir simulation.

3.3 Numerical Solution

3.3.1 Electrodynamic problem

The equation governing transport of charge solved here, which includes the cross-coupling of current flow j with gradients in water potential, concentration and temperature, can be extracted from equation (3.1)

$$j = -\sigma_{fs}(S_w)\nabla U - L_{EK}(S_w)\nabla\Phi - L_{ED}(S_w)\nabla C_f - L_{TE}(S_w)\nabla T \quad (3.2)$$

The coupling terms L_x are functions of the electrical conductivity of the fluid saturated rock σ_{fs} and the so-called coupling coefficients c_x (Jackson et al., 2010)

$$L_x = \sigma_{fs}c_x \quad (3.3)$$

where subscript x represents EK, ED or TE. The coupling coefficients (c_x) are petrophysical properties that relate electrical potential to gradients in water potential, concentration and temperature, and have units of $V\cdot Pa^{-1}$, $V\cdot M^{-1}$ and $V\cdot K^{-1}$, respectively.

Given that charge is conserved and assuming no net current flow across the boundaries of the model domain, then

$$\nabla \cdot j = 0 \quad (3.4)$$

Combining equations (3.2) and (3.4) results in

$$\nabla \cdot (\sigma_{fs}(S_w)\nabla U) = -\nabla \cdot (L_{EK}(S_w)\nabla\Phi) - \nabla \cdot (L_{ED}(S_w)\nabla C_f) - \nabla \cdot (L_{TE}(S_w)\nabla T) \quad (3.5)$$

In order to solve for the SP (U), equation (3.5) is discretised and solved for given values of saturation (S_w), water potential (Φ), salt concentration (C_f) and temperature (T) and appropriate values of σ_{fs} , L_{EK} , L_{ED} and L_{TE} . The S_w , Φ , C and T data can be obtained using any commercial or academic reservoir simulator. The resulting values usually represent discrete properties defined at the centre of each grid cell of the model. To be consistent with this, we use a control-volume-finite-difference method to discretise and solve equation (3.5). We assume that the simulator uses either a regular Cartesian grid or a corner-point grid. Many commercial and academic reservoir simulation codes are compatible with these schemes for discretising space (e.g. Schlumberger, 2010; Voss and Provost, 2002).

3.3.2 Discretisation for numerical solution

A one-dimensional system is used to explain the discretisation (Figure 3.1) and the final equations in the 3D form are shown in Appendix A. The domain is divided into grid cells with properties of interest defined at the centre of each cell.

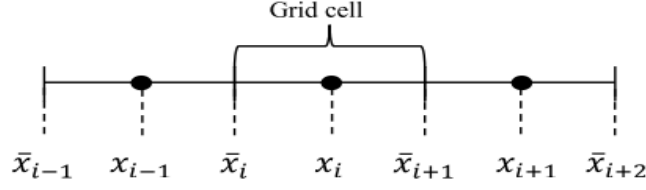


Figure 3.1: An example of a 1D grid system.

For simplicity, the numerical solution will be demonstrated considering only the EK potential; the procedure is the same to obtain the ED and TE potentials, replacing water potential Φ by concentration C or temperature T , and L_{EK} by L_{ED} or L_{TE} , respectively.

For a non-boundary cell such as cell i in Figure 3.1, equation 3.5 can be written as

$$\frac{d}{dx} \left(\sigma_{fs} \frac{dU}{dx} + L_{EK} \frac{d\Phi}{dx} \right) = 0 \quad (3.6)$$

Integrating equation 3.6 over cell i results in

$$\begin{aligned} \int_{\bar{x}_i}^{\bar{x}_{i+1}} \frac{d}{dx} \left(\sigma_{fs} \frac{dU}{dx} + L_{EK} \frac{d\Phi}{dx} \right) dx \\ = \left[\left(\sigma_{fs_{\bar{x}_{i+1}}} \frac{dU}{dx} \right)_{\bar{x}_{i+1}} - \left(\sigma_{fs_{\bar{x}_i}} \frac{dU}{dx} \right)_{\bar{x}_i} \right] + \left[\left(L_{EK_{\bar{x}_{i+1}}} \frac{d\Phi}{dx} \right)_{\bar{x}_{i+1}} - \left(L_{EK_{\bar{x}_i}} \frac{d\Phi}{dx} \right)_{\bar{x}_i} \right] = 0 \end{aligned} \quad (3.7)$$

Substituting $\frac{dU}{dx}$ and $\frac{d\Phi}{dx}$ with their central difference approximation leads to

$$\left[\left(\sigma_{fs_{\bar{x}_{i+1}}} \frac{U_{x_{i+1}} - U_{x_i}}{x_{i+1} - x_i} \right) - \left(\sigma_{fs_{\bar{x}_i}} \frac{U_{x_i} - U_{x_{i-1}}}{x_i - x_{i-1}} \right) \right] + \left[\left(L_{EK_{\bar{x}_{i+1}}} \frac{\Phi_{x_{i+1}} - \Phi_{x_i}}{x_{i+1} - x_i} \right) - \left(L_{EK_{\bar{x}_i}} \frac{\Phi_{x_i} - \Phi_{x_{i-1}}}{x_i - x_{i-1}} \right) \right] = 0 \quad (3.8)$$

where variables U_{x_i} and Φ_{x_i} are identified at cell centres and $\sigma_{fs_{\bar{x}_i}}$ and $L_{EK_{\bar{x}_i}}$ are identified at cell faces.

To further simplify equation 3.8, it can be written as

$$a_{\bar{x}_{i+1}} U_{x_{i+1}} + a_p U_{x_i} + a_{\bar{x}_{i-1}} U_{x_{i-1}} = b_{\bar{x}_{i+1}} \Phi_{x_{i+1}} + b_p \Phi_{x_i} + b_{\bar{x}_{i-1}} \Phi_{x_{i-1}} \quad (3.9)$$

Where

$$a_{\bar{x}_{i+1}} = \frac{\sigma_{fs_{\bar{x}_{i+1}}}}{x_{i+1} - x_i} \quad (3.10a),$$

$$a_{\bar{x}_{i-1}} = \frac{\sigma_{fs_{\bar{x}_i}}}{x_i - x_{i-1}} \quad (3.10b)$$

$$a_p = -\frac{\sigma_{fs_{\bar{x}_{i+1}}}}{x_{i+1} - x_i} - \frac{\sigma_{fs_{\bar{x}_i}}}{x_i - x_{i-1}} = -(a_{\bar{x}_{i+1}} + a_{\bar{x}_{i-1}}) \quad (3.10c)$$

$$b_{\bar{x}_{i+1}} = -\frac{L_{EK_{\bar{x}_{i+1}}}}{x_{i+1} - x_i} \quad (3.11a), \quad b_{\bar{x}_{i-1}} = -\frac{L_{EK_{\bar{x}_i}}}{x_i - x_{i-1}} \quad (3.11b)$$

$$b_p = \frac{L_{EK_{\bar{x}_{i+1}}}}{x_{i+1} - x_i} + \frac{L_{EK_{\bar{x}_i}}}{x_i - x_{i-1}} = -(b_{\bar{x}_{i+1}} + b_{\bar{x}_{i-1}}) \quad (3.11c)$$

Equation 3.9 can be applied to all non-boundary cells. In boundary cells, we choose to set $\nabla U = 0$, consistent with equation (3.4) which assumes that no current enters or leaves the domain, by assigning virtual cells outside the model boundary with the same electrical potential as the boundary cells.

3.3.3 Interface properties

Solution of equations 3.9–3.11 requires values for the properties at the interface between connected grid cells ($\sigma_{fs_{\bar{x}_{i+1}}}$ and $L_{EK_{\bar{x}_i}}$). Earlier approaches (Ijioma, 2016; Graham et al., 2018) used a harmonic average of the cell-centre values, which is a reasonable assumption when the polarity of the coupling terms L for the two connected grid cells are the same. However, coupling terms can have variable polarity, depending on the rock mineralogy, brine composition and mineral surface wettability (e.g. Leinov and Jackson 2014; Jackson et al., 2016). Thus, there is no guarantee that the coupling terms in each connected cell have the same polarity. When they have opposing polarity, the harmonic mean is not the appropriate averaging scheme to calculate the coupling term at the interface.

The new averaging scheme proposed in this work uses conservation of charge to recognise that the total current (sum of the conduction and streaming currents) must be continuous at the interface to give

$$I_{\bar{x}_{i+1}} = -\sigma_{fs_{\bar{x}_{i+1}}} \nabla U_{\bar{x}_{i+1}} - L_{EK_{\bar{x}_{i+1}}} \nabla \Phi_{\bar{x}_{i+1}} \quad (3.12a)$$

$$I_{x_i} = -\sigma_{fs_{x_i}} \nabla U_{x_i} - L_{EK_{x_i}} \nabla \Phi_{x_i} \quad (3.12b)$$

$$I_{x_{i+1}} = -\sigma_{fs_{x_{i+1}}} \nabla U_{x_{i+1}} - L_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}} \quad (3.12c)$$

where x_i and x_{i+1} are the location of the centres of grid cells i and $i + 1$, while $\bar{x}_{i+1}$ represents the location of the interface between the two grid cells (Figure 3.2). The subscripts in equation (3.12) reflect the location at which each property (I , σ_{fs} , ∇U or L_{EK}) is calculated. The first term on the right-hand side of equation (3.12) describes the conduction current, while the second term represents the streaming

current. The interface properties are calculated by assuming continuous total current ($I_{\bar{x}_{i+1}} = I_{x_i} = I_{x_{i+1}}$). The final equations for calculating the interface properties are as follows (detailed derivation is shown in Appendix A)

$$\sigma_{fs\bar{x}_{i+1}} = \frac{\sigma_{fsx_i} \sigma_{fsx_{i+1}} (x_{i+1} - x_i)}{(x_{i+1} - \bar{x}_{i+1}) \sigma_{fsx_i} + (\bar{x}_{i+1} - x_i) \sigma_{fsx_{i+1}}} \quad (3.13)$$

$$L_{EK\bar{x}_{i+1}} = \frac{\sigma_{fsx_{i+1}} L_{EKx_i} (\bar{x}_{i+1} - x_i) + \sigma_{fsx_i} L_{EKx_{i+1}} (x_{i+1} - \bar{x}_{i+1})}{(x_{i+1} - \bar{x}_{i+1}) \sigma_{fsx_i} + (\bar{x}_{i+1} - x_i) \sigma_{fsx_{i+1}}} \quad (3.14)$$

The same formulations are used for the ED and TE potentials, replacing L_{EK} and $\nabla\Phi$ by L_{ED} and ∇C or L_{TE} and ∇T , respectively.

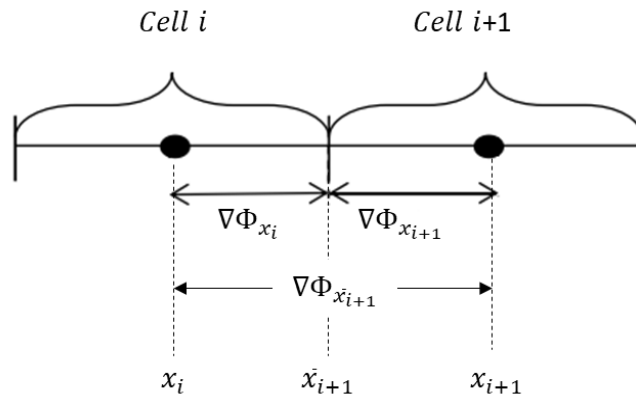


Figure 3.2: Variation in grid properties at the interface between two connected grid cells i and $i + 1$.

3.3.4 Fault modelling

Faults represent planar discontinuities in the rock mass across which rock units are offset. These discontinuities may modify fluid flow and component and heat transport, depending on the properties of the fault (Cherubini et al., 2013; Knipe et al., 1998; Nurafiqah et al., 2019). Thus, they may modify charge transport in response to gradients in water potential, concentration and temperature. Faults may also modify the conduction currents that maintain overall electroneutrality. Hence, it is important to include them in reservoir models.

In many numerical models, the (corner-point) grid follows the geometry of the rock layers and the grid-cells are offset across fault planes in a manner similar to the way in which the rocks are offset (e.g. Qu et al., 2015; Figure 3.3). Thus, cells juxtaposed across the fault are not logically neighbours and must be connected using so-called ‘non-neighbour’ connections or NNCs (e.g. Schlumberger, 2010).

In our example faulted grid (Figure 3.3b), grid cells $(i + 1, j + 2)$ and $(i + 2, j)$ are juxtaposed across the fault and NNCs must be defined between these cells to model charge transport across the fault. We also need to identify new boundary cells resulting from the offset of the grid across the fault. In our example faulted grid (Figure 3.3b), grid cell $(i + 1, j + 1)$ is a boundary cell. The SP solver is equipped with built-in functions to specify NNCs and boundary cells in order to correctly model charge transport. Modelling the charge flux into/out of each grid cell requires knowledge of all the grid cells connected to that cell. In our 2D example faulted grid (Figure 3b), grid cell $(i + 1, j + 2)$ has three neighbouring connections with cells $(i + 1, j + 1)$, $(i, j + 2)$ and $(i + 1, j + 3)$ and one NNC with cell $(i + 2, j)$.

Reservoir simulators that use this approach to represent faults typically generate a list of NNCs across fault surfaces. However, this list may be modified based on a cut-off transmissibility value (default or user-defined) below which a NNC is deleted (Schlumberger, 2010). It is assumed that no fluid flow occurs across the deleted NNCs. However, there may be charge transport across these connections depending on the coupling terms and rock conductivity in the cells on each side. Hence, the NNC list calculated for fluid flow in a reservoir simulator may not be suitable for charge transport in the SP solver presented here. Hence, we developed a bespoke function to generate the NNC list for the SP solver. The NNC list is generated based on the coordinates of the corner points of each cell, identifying any deviation in the grid geometry from the non-faulted case and generating NNC’s across the boundaries of all juxtaposed cells (Figure 3.3). For the non-faulted case, the depths of the corner points at the interface between each two neighbouring cells are the same, while in the presence of fault, layers offset across the fault interface, and hence, the depths of the corner points are not the same. The NNC list is generated by comparing the vertical offset in the depths of the corner points between all the cells across the fault interface. The layers offset may not be uniform resulting in multiple NNCs for one cell (Figure 3.3b, grid cell $(i + 1, j + 3)$). In this case, the interface properties calculated according to

equations (3.13) and (3.14) need to be corrected by multiplying by the ratio of the cross-sectional area in contact with each non-logical neighbour to the total cross-section area.

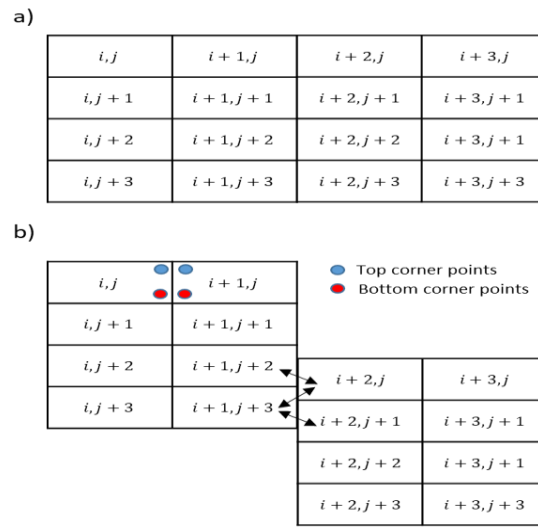


Figure 3.3: a) Example of an unfaulted 2D mesh. b) Example of a 2D mesh offset across a simple vertical fault. Arrows represent the non-neighbouring connections that allow flow and transport between cells on opposite sides of the fault.

3.3.5 Local grid refinement

We have found that in many models used to simulate SP monitoring scenarios, the grid resolution that provides a reasonable approximation of fluid flow and heat and mass transport is too coarse for accurate prediction of the SP, especially in the vicinity of SP monitoring locations where it may be necessary to capture changes in the hydrodynamic properties (e.g. water saturation, potential, concentration and temperature) at higher resolution. However, refining the grid across the entire model domain may be excessively computationally expensive. Instead, it may be sufficient to locally refine the grid (termed here ‘local grid refinement’ [LGR] or ‘child’ model) around SP monitoring locations within the coarse (‘parent’) model (Ijioma, 2016; Figure 3.4). Many commercial and academic reservoir simulation codes allow LGR and we include functionality to allow these LGRs to be included in the SP solver.

A ‘ghost-node’ model-linking method (James et al. 2006) is used to couple the parent model with the LGR with appropriate LGR boundary conditions. The SP is simulated on the parent model, and the electrical (SP, rock conductivity, coupling terms) and dynamic (water saturation, potential, concentration and temperature) properties in each parent grid cell bordering the LGR are used to

determine boundary conditions for simulating SP within the LGR. At the boundaries of the LGR, ghost cells similar in dimension to the LGR cells are placed in the parent cells (e.g. cells: $i_c - 1, j_c$ in Figure 3.4). Properties for these ghost cells are calculated by linearly interpolating values between the parent cells. For example, pressure and SP for ghost cell $i_c - 1, j_c$ (Figure 3.4) are interpolated between the parent cell hosting that ghost cell ($i, j + 1$ in Figure 3.4) and the parent cell hosting the LGR ($i + 1, j + 1$ in Figure 3.4). The electrodynamic model is then solved within the LGR subjected to the boundary conditions identified in the ghost cells.

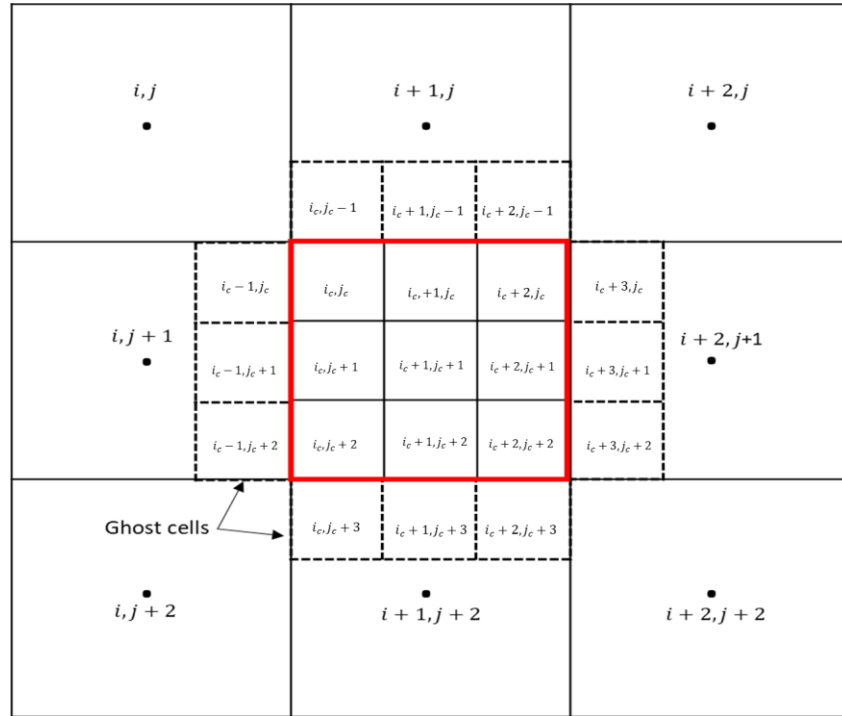


Figure 3.4: Example LGR within the parent grid (denoted by the red boundary). Cells outlined by dashed lines are the ghost cells introduced at the boundaries of the LGR. Subscript c (e.g., i_c, j_c) denotes cells within the LGR or ghost cells at the LGR boundaries.

3.3.6 Electrical properties

In order to solve equation (3.2), the concentration- and temperature-dependent material properties (rock conductivity (σ_{fs}) and coupling terms [L_{EK}, L_{ED}, L_{TE}]) must be specified. The operation of the SP solver is independent of the models used to describe these material properties, and the user can modify the code to implement their own preferred descriptions. However, here we describe the approach used in the code at present, and that was used to obtain the results presented in this work.

The saturated rock conductivity is calculated using the well-known Archie's equation (Glover et al., 2000)

$$\sigma_{fs} = \phi^m \sigma_w S_w^n \quad (3.15)$$

where ϕ is the porosity, m is the cementation exponent, S_w is the water saturation, n is the saturation exponent, and σ_w is the water conductivity (S/m). The water conductivity is calculated as a function of the salt concentration (C , M/L) and temperature (T , °C) using (Sen and Goode, 1992; Figure 3.5a)

$$\sigma_w = (5.6 + 0.27T - 1.5 \times 10^{-4}T^2)C_f - \frac{2.36 + 0.099T}{1 + 0.214C_f^{0.5}} C_f^{1.5} \quad (3.16)$$

The coupling terms (L_{EK}, L_{ED}, L_{TE}) are functions of the rock conductivity and the associated coupling coefficients (C_{EK}, C_{ED}, C_{TE}). First, we will consider the EK coupling coefficient (C_{EK}). A number of experimental and theoretical studies have characterised the EK coupling coefficients for sandstones (e.g. Revil and Cerepi, 2004; Jaafar et al., 2009; Vinogradov et al., 2010; Glover et al., 2012; Walker et al., 2014; Vinogradov and Jackson, 2015; Esmaili et al., 2016; Vinogradov et al., 2018; Walker and Glover, 2018; Glover, 2018; Li et al., 2018) and carbonates (e.g. Jackson and Vinogradov, 2012; Chen et al., 2014; Alroudhan et al., 2016; Jackson et al., 2016; Al Mahrouqi et al., 2017; Ghommam et al., 2018; Collini et al., 2020). Here, we focus on sandstones, although, as mentioned above, the C_{EK} model used here can easily be modified or changed for other rock types.

Most of the published EK coupling coefficient data for sandstones were obtained for fully saturated ($S_w = 1$) conditions at laboratory temperature. We describe the observed trend with brine concentration (ionic strength) using (Vinogradov et al., 2010)

$$C_{EK}(S_w = 1) = -1.36 C_f^{-0.9123} \times 10^{-9} \quad (3.17)$$

Equation (3.17) fits data measured in sandstone samples saturated with simple monovalent NaCl brines (Figure 3.5b). Alternative expressions can easily be implemented in the code. The limited available data suggest that the EK coupling coefficient for complex natural brines is smaller in magnitude for a given ionic strength compared to the values in monovalent brines shown in Figure 3.5b (Vinogradov et al., 2018; Li et al., 2018). We neglect any temperature dependence of the EK coupling coefficient, which

is consistent with the findings of previous studies that showed it is approximately independent of temperature over the range of 20 °C–120°C in brines of moderate to high ionic strength (Reppert and Morgan, 2003a, 2003b; Vinogradov and Jackson, 2015; Vinogradov et al., 2018).

In reservoirs that are partially saturated with water, such as oil and gas reservoirs and unconfined aquifers, the EK coupling coefficient is a function of water saturation. A number of studies have measured and/or modelled the relationship between coupling coefficient and water saturation in sandstone and carbonate rocks (Wurmstich and Morgan, 1994; Perrier and Morat, 2000; Guichet et al., 2003; Revil and Cerepi, 2004; Linde et al., 2007; Revil et al., 2007; Jackson, 2010; Vinogradov and Jackson, 2011; Gulamali, et al., 2012; Allègre et al., 2012; Jougnot et al., 2012; Jackson et al., 2012b; Zhang et al., 2017; Soldi et al., 2019; Vinogradov et al., 2021). Here, we follow the approach presented by Jackson et al. (2012b) to describe the saturation dependence of the coupling coefficient, noting that it is trivial to replace this model in the code with other published or new models. We assume that the coupling coefficient at the residual non-wetting phase saturation is the same as that at fully water saturated conditions, and define a saturation-dependent relative coupling coefficient (C_{rEK})

$$C_{rEK} = S_{wn}^{0.6} \quad (3.18)$$

$$S_{wn} = \frac{S_w - S_{wirr}}{1 - S_{wirr} - S_{nwr}} \quad (3.19)$$

$$C_{EK}(S_w) = C_{EK}|_{S_w=1} C_{rEK}(S_w) \quad (3.20)$$

where S_{wn} is the normalised normalised water saturation, S_{wirr} is the irreducible water saturation and S_{nwr} is the residual non-wetting phase saturation. Equation (3.18) was chosen to match the results of a bundle capillary tube model presented by Jackson (2010) and experimental data obtained by Revil and Cerepi (2004).

Next, we consider the ED and TE coupling coefficients. As remarked earlier, ED and TE potentials have two end-member cases: pure exclusion and pure diffusion (Sections 2.2.1.2 and 2.2.1.3; Figure 3.5c, d). The salinity and temperature dependence of the ED and TE coupling coefficients for these two cases are given by (Revil, 1999; Jackson et al., 2012b; Leinov and Jackson, 2014; Jackson, 2015)

$$C_{ED}|_{ed} = -8.61 \times 10^{-2} \frac{(2t_{Na} - 1)T}{C_f} \text{ mV} \cdot \text{M}^{-1} \quad (3.21)$$

$$C_{ED}|_{ee} = -8.61 \times 10^{-2} \frac{T}{C_f} \text{ mV} \cdot \text{M}^{-1} \quad (3.22)$$

$$C_{TE}|_{ed} = -1.984 \times 10^{-1} (2t_{Na} - 1) (\log C_f) + 1.059 t_{Na} - 5.673 \times 10^{-1} \text{ mV} \cdot \text{K}^{-1} \quad (3.23)$$

$$C_{TE}|_{ee} = -1.984 \times 10^{-1} (\log C_f) + 5.953 \times 10^{-1} \text{ mV} \cdot \text{K}^{-1} \quad (3.24)$$

$$t_{Na} = \begin{cases} 0.39 & C < 0.09 \text{ M} \\ 3.66 \times 10^{-1} - 2.12 \times 10^{-2} (\log_{10} C_f) & C > 0.09 \text{ M} \end{cases} \quad (3.25)$$

where subscripts *ed* and *ee* refer to pure diffusion and pure exclusion cases, respectively. t_{Na} is the macroscopic Hittorf transport number for the Na ions, noting that this approach assumes charge transport is dominated by Na^+ and Cl^- ions arising from the dissociation of NaCl, which is a reasonable assumption for subsurface reservoirs (Numbere et al., 1977; Angelis, 2005). Experimentally measured data on shales, sandstones and carbonate rock samples lie between the pure exclusion and diffusion limits for both the ED and TE potentials (Figure 3.5c,d). Note that the effect of temperature on the TE coupling coefficient is neglected in equations (3.23) and (3.24) because of the small variation in the TE coefficient ($< 8\%$) over the temperature range 20°C – 120°C (Jackson et al., 2012b).

The relative contribution of the exclusion and diffusion components of the EC and TE potentials can be defined by a dimensionless number termed the ‘exclusion efficiency’ (ε). An exclusion efficiency of unity corresponds to an exclusion-dominated ED or TE potential, while an efficiency of zero corresponds to a diffusion-dominated ED or TE potential (Leinov and Jackson, 2014). The ED and TE coupling coefficients are modelled as a function of exclusion efficiency as (Graham et al., 2018)

$$C_x = \varepsilon_x \cdot (C_x|_{ee} - C_x|_{ed}) + C_x|_{ed} \quad (3.26)$$

where subscript x refers to either ED or TC. Unlike EK potential, ED and TE potentials can be generated across impermeable layers if there is a concentration or temperature gradient, even in the absence of any water flow. The exclusion efficiency in fully saturated rocks varies with the rock pore size (Leinov and Jackson, 2014), so an appropriate value of exclusion efficiency value must be assigned to each rock type; for example, MacAllister et al. (2019) measured values of $\varepsilon=0$ – 0.1 and $\varepsilon=0.3$ – 0.4 for carbonates and shales, respectively.

In reservoirs partially saturated with water, the exclusion efficiency also varies with water saturation (Ortiz et al., 1973). We use here the approach described by Ortiz et al. (1973) to model the behaviour of the exclusion efficiency at the saturation endpoints ($S_w = S_{wirr}$ and $S_w = 1 - S_{nwr}$). At low water saturation, Ortiz et al. (1973) suggested that the excess charge is confined to thin water films and small, water-occupied pores from which co-charge is efficiently excluded. Thus, the ED and TE potentials are dominated by exclusion ($\varepsilon = 1$ and $C_x(S_{wirr}) = C_x|_{ee}$). Conversely, at high water saturation, the water occupies most of the pores and the EC and TE potentials are dominated by diffusion (ε is the minimum for the rock type of interest). At intermediate saturations, we model the saturation-dependence of the exclusion efficiency as (Jackson et al., 2012b)

$$\varepsilon_x = (1 - S_{wn})^3 \quad (3.27)$$

where ε_x is the ED or TE exclusion efficiency at intermediate saturation. Equation (3.27) was fitted to match the data presented in Ortiz et al. (1973) for the ED coupling coefficient, and we assume the same behaviour for the TE relative coupling coefficient.

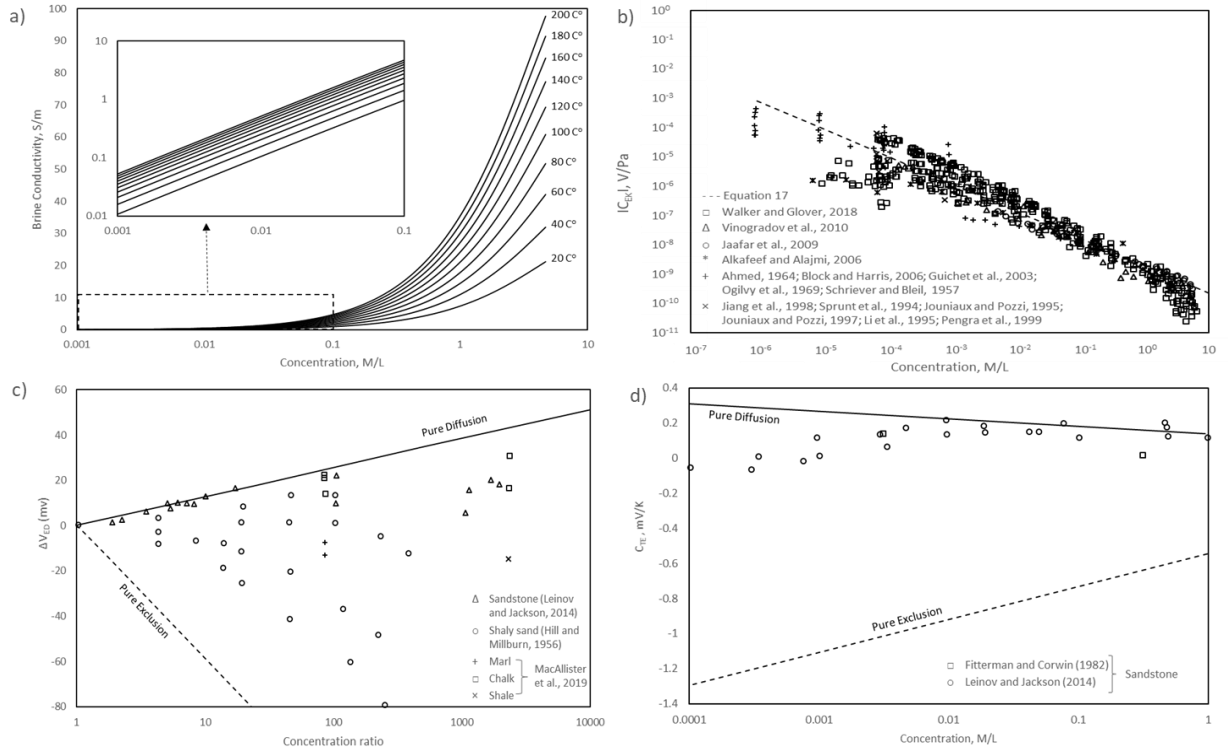


Figure 3.5: a) Water conductivity versus brine concentration (ionic strength) at different temperatures. b) EK coupling coefficient versus brine concentration. c) ED coupling coefficient versus brine concentration ratio. d) TE coupling coefficient versus brine concentration.

3.3.7 Numerical solution of the linear system of discretised equations

Equations (3.9–3.11) were used to write the formulation in matrix form considering all the grid cells in the system

$$Ax = By \quad (3.28)$$

where A and B are $n \times n$ sparse matrices (n is the total number of grid cells) comprising the a and b terms in equation (3.9), respectively. x and y are $n \times 1$ vectors representing the unknown EK, ED or TE potential and the known water potential, concentration or temperature from the reservoir simulation, respectively.

MacAllister et al. (2018) and Graham et al. (2018) found that the solution obtained for x using an iterative solver was unstable and highly sensitive to changes in the iterative solver tolerance, and the latter recommended using a direct solver to obtain a stable solution. Therefore, we typically use the ‘mldivide’ function in MATLAB as a direct solver to solve for x in equation (3.28). Although this approach is slower than the various iterative methods implemented in MATLAB, speed is not essential as we do not need to solve for the SP at numerous timesteps. The strength of the ‘mldivide’ function in solving linear systems is its ability to dispatch an appropriate solver for each matrix depending on matrix density and fill pattern. This approach aims to minimize computation time. We solve equation (3.28) for each of the EK, ED and TE potentials using the appropriate material properties and water potential, concentration or temperature as required. The total SP is obtained by summing over the EK, ED and TE potentials thus obtained.

As the SP signal is a potential difference between two points, the modelled SP is the difference in potential between a given location and that of a reference location, which is usually chosen at some distance above the reservoir layer.

3.4 Results

3.4.1 Model validation

A simple 1D case was used to confirm that the code works correctly. The test case involved a sandstone reservoir measuring 200 x 100 x 50 m with one oil/water production well and one water injection well. The ECLIPSE reservoir simulator was used to model two scenarios: first, water displacing water to represent single-phase flow and second, water displacing oil to represent two-phase flow.

First, we tested the EK potential solver. Salinity and temperature were assumed to be constant across the reservoir (0.5 M/L and 80°C), so that EK potential is the only contributor to the overall SP. We used a constant value of the EK coupling coefficient for the flow of water at fully water saturated conditions and at the residual non-wetting (oil) phase saturation ($C_{ek}(S_w = 1) = C_{ek}(S_w = 1 - S_{nwr}) = 2.5 \times 10^{-9} \text{ VPa}^{-1}$). For the two-phase scenarios, we used fluid viscosities and relative permeability curves that yield a piston-like displacement such that oil is flowing at the irreducible water saturation ahead of the displacement front ($S_w = S_{wirr}$) and water is flowing at residual oil saturation behind the front ($S_w = 1 - S_{nwr}$). These material properties were used in the SP solver along with the outputs of the ECLIPSE reservoir simulator (S_w, Φ_w) to predict the EK potential.

Results are shown in Figure 3.6 for both single- and multi-phase flow scenarios. For the single-phase scenario, we know that the correct solution should yield a linear variation in EK potential from the inlet to the outlet boundary, with the most positive value adjacent to the inlet boundary where the water potential has the largest positive value. Moreover, a cross-plot of EK potential against water potential should yield a linear relationship, with the gradient giving the EK coupling coefficient. We find that the SP solver predictions confirm the expected behaviour irrespective of the grid resolution tested (Figure 3.6b), and the coupling coefficient obtained from the numerical solution is identical to the input value to high precision (Figure 3.6c).

For the multi-phase scenario, we know that the correct solution should yield constant EK potential ahead of the displacement front where there is no water flow, and a linear variation in EK potential from the inlet to the location of the displacement front (see, for example, Figure 14 in Jackson, 2015).

Moreover, a cross-plot of EK potential against water potential in the region behind the displacement front should yield a linear relationship, with the gradient giving the EK coupling coefficient. As is well known (e.g. Aziz and Settari, 1979), numerical solutions of the multi-phase displacement problem are highly dependent on grid resolution. However, as the grid is refined, the ECLIPSE simulator results converge to capture the correct sharp displacement front across which the water saturation changes sharply and the water phase potential changes gradient (Figure 3.6d, e). The SP solver results also converge to give the correct solution for the EK potential (Figure 3.6f); note that the rate of convergence is dominated by convergence of the ECLIPSE simulation results, not the SP solver itself. Behind the displacement front, the coupling coefficient obtained from the numerical solution approaches the input value as the grid is refined and is the same as the input value to high precision for the most refined case tested (Figure 3.6g). Thus, we have confidence that the SP solver returns correct solutions for the EK potential for both single- and multi-phase flow scenarios.

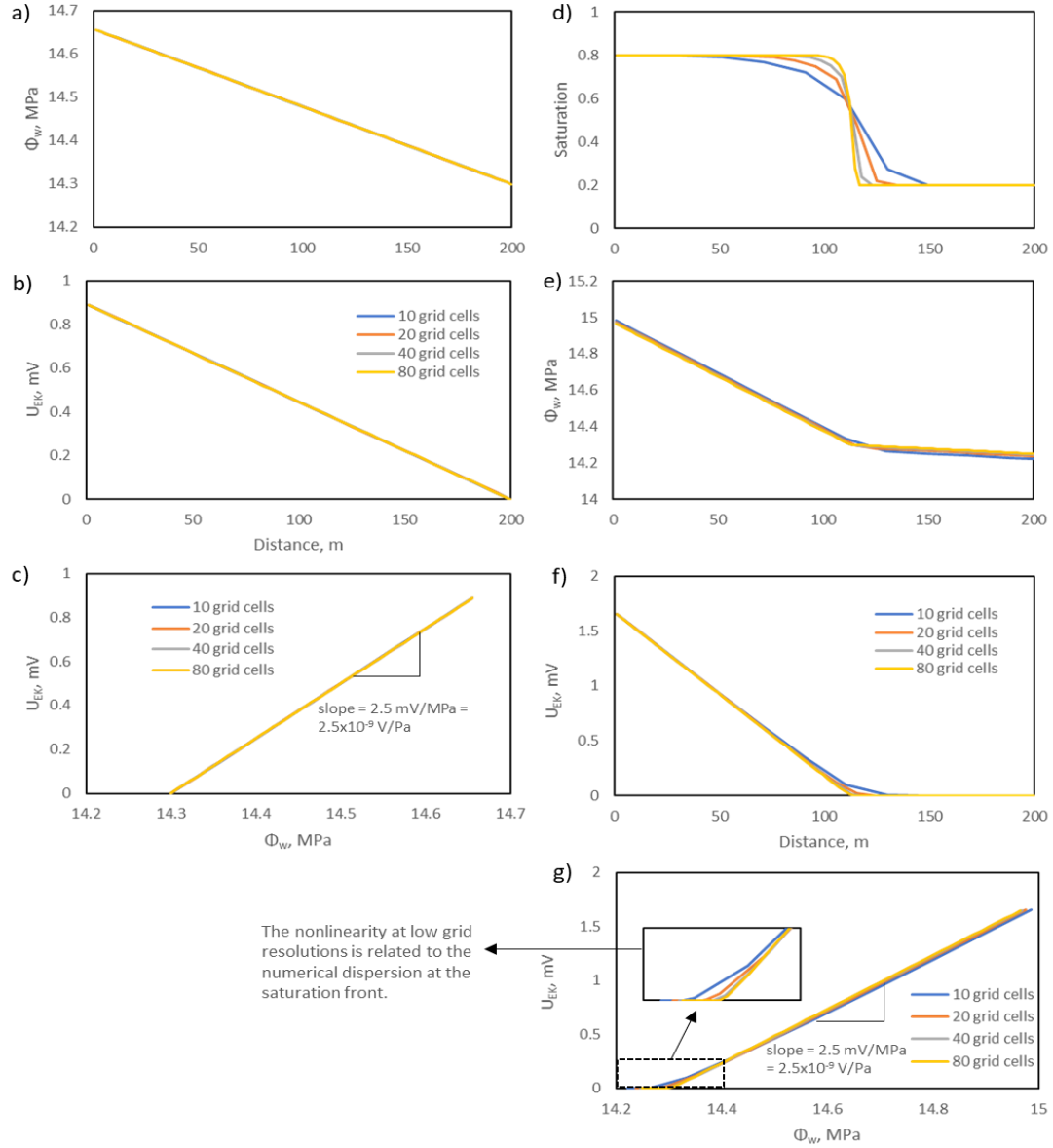


Figure 3.6: Numerical solutions from a single timestep of the EK validation model as a function of distance from the inlet to the outlet boundary. A) Water potential for the single-phase problem. b) EK potential for the single-phase problem. c) Cross-plots of EK potential against water potential for the single-phase problem. d) Water saturation for the multi-phase problem. e) Water potential for the multi-phase problem. f) EK potential for the multi-phase problem. g) Cross-plots of EK potential against water potential for the multi-phase problem. Lines in each plot correspond to different grid resolutions used in the model between the inlet and outlet boundaries.

To validate the ED potential solver, we modelled injection of lower salinity (ionic strength) brine ($C_{inj} = 0.5\text{M/L}$) into a reservoir containing higher salinity brine ($C_{res} = 1\text{M/L}$) using the ECLIPSE reservoir simulator. We assumed constant reservoir temperature of 80°C . For the single-phase scenario, we assumed an exclusion efficiency of zero for the reservoir rock (similar to sandstone) and described

the saturation dependence using equation (3.27) in the multi-phase scenario. These material properties together with the outputs of the ECLIPSE reservoir simulator (S_w, C) were used in the SP solver to predict the ED potential.

Results are shown in Figure 3.7 for both single- and multi-phase flow scenarios. We know that the correct solution should yield constant ED potential behind the trailing edge of the salinity front and ahead of the leading edge of the salinity front (representing maximum and minimum values, respectively). Across the salinity front, the ED potential varies between these two values. We find that the SP solver predictions confirm the expected behaviour. However, the grid resolution used significantly affects the modelled variation of the ED potential across salinity front, especially for the multi-phase scenario (Figures 3.7b, f). This is primarily due to the grid-resolution-dependence of the solutions for salinity (and water saturation for the multi-phase case) in the ECLIPSE simulator (Fig. 3.7a, d, e), rather than the solution for ED in our SP solver. As the grid is refined, the solutions converge as expected, although high resolution is required for the multi-phase case.

We confirm the validity of the SP solver solution by plotting the ED coupling coefficient values used as input to the SP code together with the simulated coefficients, determined using the ED potential determined by the solver and associated salinity (recalling $C_{ED} = \Delta U_{ED} / \Delta C_f$) for each neighbouring cells as a function of distance from the inlet to the outlet boundary (Figure 3.7c,g). The coupling coefficient obtained from the numerical solution is the same as the input value to high precision. Therefore, we have confidence that the SP solver returns correct solutions for the ED potential for both single and multi-phase flow scenarios.

Finally, to validate the TE potential solver, we modelled injection of cooler water ($T_{inj} = 20^\circ\text{C}$) into a hotter reservoir ($T_{res} = 80^\circ\text{C}$) using the ECLIPSE reservoir simulator. Salinity was assumed to be constant ($C_{res} = C_{inj} = 0.5 \text{ M}$). We again assumed an exclusion efficiency of zero for the reservoir rock for the single-phase scenario and described the saturation dependence of the exclusion efficiency using equation (3.27) in the multi-phase scenario. These material properties together with the outputs of the ECLIPSE reservoir simulator (S_w, T) were used in the SP solver to predict the TE potential.

Results are shown in Figure 3.8 for both single- and multi-phase flow scenarios. We know that the correct solution should yield constant TE potential behind the trailing edge of the temperature front and ahead of the leading edge of the temperature front (representing maximum and minimum values, respectively). The TE potential varies between these two values across the temperature front. The SP solver predictions are consistent with the expected behaviour. However, the variation of the TE potential across the temperature front is highly affected by the grid resolution, especially for the multi-phase scenario (Figures 3.8b, f). This is primarily because of the grid-resolution-dependence of the solutions for temperature (and water saturation for the multi-phase case) in the ECLIPSE simulator (Figure 3.8a,d and e), rather than the solution for TE in our SP solver. As expected, the TE solutions converge as the grid is refined.

For the single-phase scenario, a cross-plot of TE potential against temperature should yield a linear relationship, with the gradient giving the TE coupling coefficient. We find that the coupling coefficient obtained from the numerical solution (0.188 mV/K; gradient from Figure 3.8c) is identical to the input value (0.188 mV/K, according to equation 3.23) regardless of the grid resolution. This confirms the validity of the SP solver for TE solutions in the single-phase scenario. For the multi-phase scenario, the validity of the TE solution is confirmed by plotting the TE coupling coefficient values used as input to the SP code, together with the simulated coefficients determined using the TE potential determined by the solver and associated temperature (recalling $C_{TE} = \Delta U_{TE} / \Delta T$) for each pair of neighbouring cells, as a function of distance from the inlet to the outlet boundary (Figure 3.8g). The coupling coefficient obtained from the numerical solution is the same as the input value to high precision. Thus, we also have confidence that the SP solver returns correct solutions for the TE potential in multiphase flow.

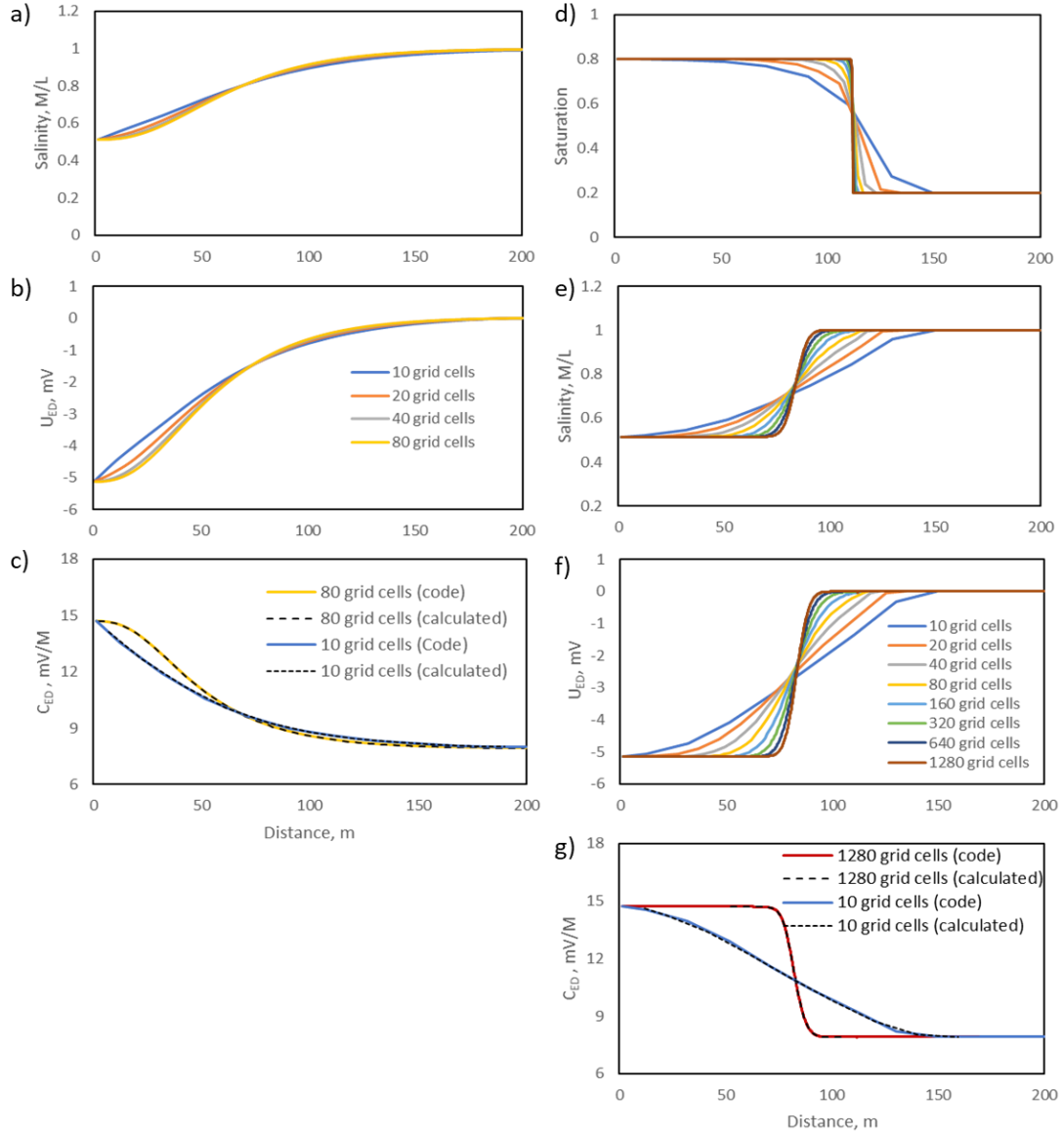


Figure 3.7: Numerical solutions from a single timestep of the ED validation model as a function of distance from the inlet to the outlet boundary. A) Water salinity for the single-phase problem. b) ED potential for the single-phase problem. c) ED coupling coefficient for the single-phase problem. d) Water saturation for the multi-phase problem. e) Water salinity for the multi-phase problem. f) ED potential for the multi-phase problem. g) ED coupling coefficient for the multi-phase problem. Lines in each plot correspond to different grid resolutions used in the model between the inlet and outlet boundaries.

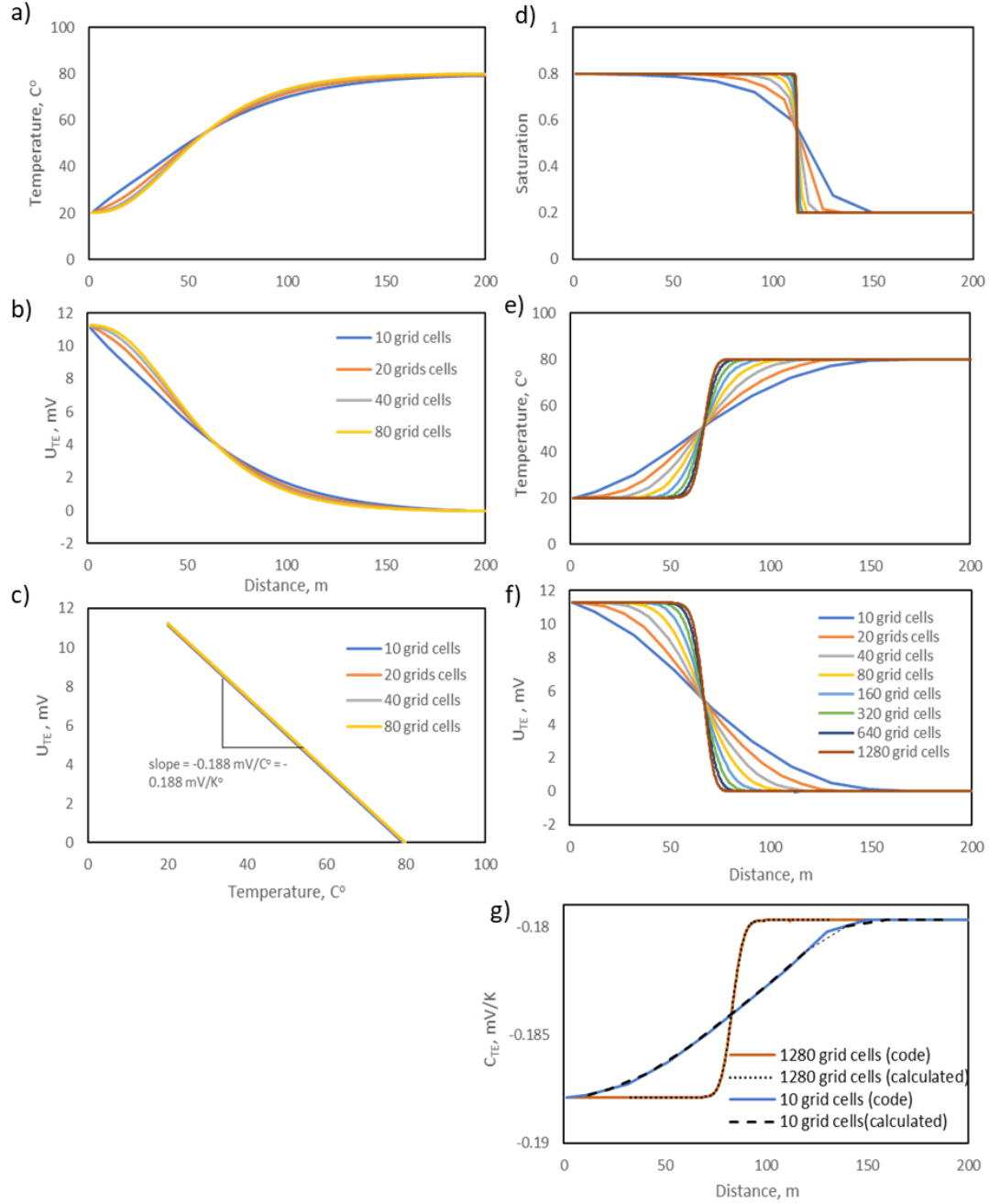


Figure 3.8: Numerical solutions from a single timestep of the TE validation model as a function of distance from the inlet to the outlet boundary. A) Temperature for the single-phase problem. b) TE potential for the single-phase problem. c) Cross-plots of TE potential against temperature for the single-phase problem. d) Water saturation for the multi-phase problem. e) Temperature for the multi-phase problem. f) TE potential for the multi-phase problem. g) Cross-plots of TE potential against temperature for the multi-phase problem. Lines in each plot correspond to different grid resolutions used in the model between the inlet and outlet boundaries.

3.4.2 Self-potential in a hydrocarbon reservoir: Brugge field model

The Brugge field case is a synthetic model that was developed to evaluate a range of history matching and production optimisation algorithms as part of an SPE Advanced Technology Workshop (Peters et al., 2010). The geological structure of the Brugge field model comprises a half dome offset across a vertical fault located at the northern edge (Figure 3.9). The area of the reservoir is approximately $10 \times 3 \text{ km}^2$ with an average thickness of 60 m. The reservoir has four stratigraphic layers: Schelde, Maas, Waal and Schie, from top to bottom. Average petrophysical properties for the reservoir layers are shown in Table 3.1, and the fluid and rock properties used are summarised in Table 3.2. The reservoir is initially saturated with oil and formation brine and overlies a water saturated aquifer (Figure 3.9); there is no gas present.

Peters et al. (2010) created an ensemble of 104 upscaled reservoir model realisations (60048 grid cells: $139 \times 48 \times 9$) varying in porosity, permeability and net to gross ratio (NTG). We randomly selected one realisation to simulate oil production supported by water injection for the purpose of this work. The production scenario considered comprises 20 oil producers and 10 water injectors. The production wells are completed in the top three stratigraphic layers, while the injection wells are completed in all four layers. A target production rate of 10000 STB/d ($1.84 \times 10^{-2} \text{ m}^3/\text{s}$) per well was modelled with a minimum flowing bottom hole pressure of 725 psi (equal to the bubble point pressure of the oil, so that no gas is evolved in the reservoir). The water injection rate was chosen to balance the total fluid production rate. The initial reservoir temperature and formation brine salinity were assumed to be 80°C and 1 M/L, respectively. The injected brine was assumed to have lower temperature (30°C) and salinity (0.5 M/L).

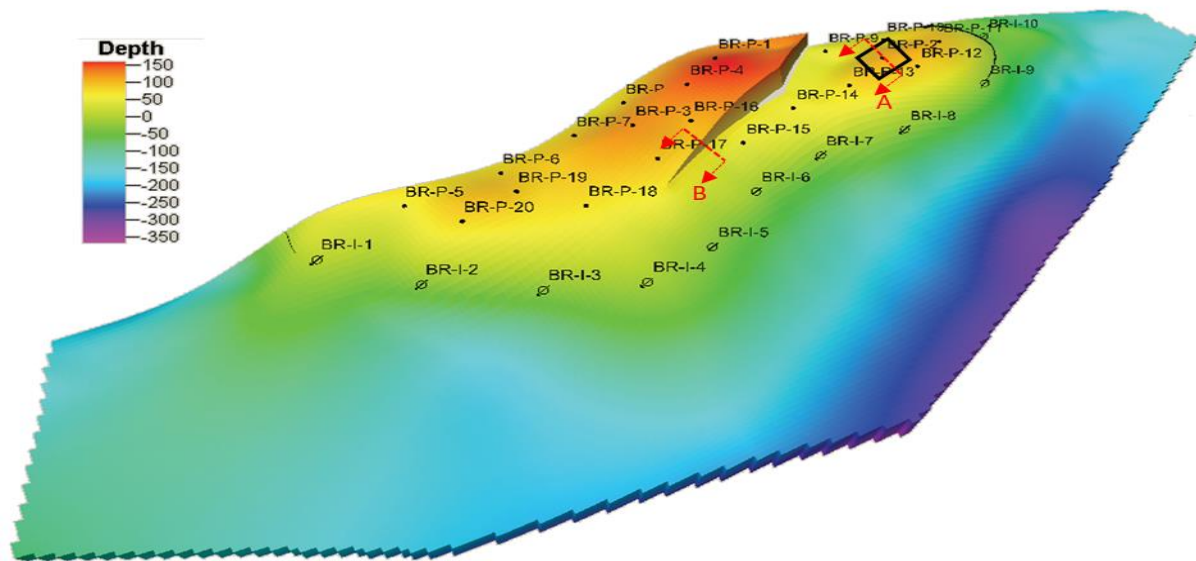


Figure 3.9: Structure of the Brugge field model showing the depth above and below the oil/water contact (in m) and the 30 wells (BR-P: production wells and BR-I: injection wells; Peters et al., 2010).

Table 3.1: Stratigraphy in the Brugge field model with main petrophysical properties (Peters et al., 2010).

Reservoir formation	Average thickness, m	Average porosity, %	Average permeability, md	Average NTG, fraction
Schelde	10	20.7	1105	0.6
Maas	20	19	90	0.88
Waal	26	24.1	814	0.97
Schie	5	19.4	36	0.77

Table 3.2: Rock and fluid used in the Brugge model.

Properties	Water	Oil	Rock
Density, kg/m ³	1000	900	-
Compressibility, 1/Pa	4.35×10^{-10}	1.34×10^{-9}	5.1×10^{-10}
Viscosity, Pa.s	0.001	0.0013	-
Irreducible water saturation	0.252	-	-
Critical water saturation	0.29	-	-
Residual oil saturation	0.15	-	-
Endpoint water relative permeability	0.3	-	-
Endpoint oil relative permeability	0.8	-	-

The average grid size in the model is $120 \times 120 \times 10$ m in the i, j and k directions, respectively, which is too coarse to accurately simulate the SP in the vicinity of a well (Jackson et al., 2012b). Therefore, we placed LGRs of resolution $4 \times 4 \times 0.5$ m around selected production wells to improve the predictions of the SP solver. Refining the grid to this level across the whole model would be computationally infeasible as the number of grid blocks required would be in excess of 1 billion. Hence, the LGR functionality in the SP solver is essential to obtain high resolution solutions around the wells of interest. A sensitivity study of the LGR resolution confirmed that the resolution used is sufficient to capture the SP solution. The SP solver was used here to predict the signals that might be recorded at a production well equipped with permanently installed downhole electrodes (Gulamali et al., 2011).

After running the dynamic simulation in ECLIPSE, the results were used as inputs for the SP solver. The model was modified in the solver to include electrically conductive, water saturated shale layers of thickness 70 m above and below the reservoir. These shale layers represent the under- and over-burden and are required for the SP modelling as electrical currents may spread beyond the reservoir. The EK coupling coefficients in the reservoir were calculated according to Section 3.3.6, but were zero in the shale layers as there is no flow. The ED and TE coupling coefficients were calculated following the approach described in Section 3.3.6. The exclusion efficiency in the reservoir was assumed to vary between 0 to 1 as a function of saturation, while a constant value of 0.4 was used in the shale layers. The SP solver was used to simulate the contributions of EK, ED, and TE to the overall SP.

The results presented here focus on the new functionality of our SP solver. We begin by considering the benefits of the LGR functionality. The effect of increased grid resolution on the solution obtained is clearly observed (Figure 3.10). The LGR solutions yields a sharper saturation front as there is less numerical diffusion (compare Figures 3.10a and 3.10c), which significantly affects the simulated SP (compare Figures 3.10b and 3.10d). The higher resolution solution delivered by the LGR shows that the SP signal extends to the production well, ahead of the moving waterfront. Consequently, monitoring of the SP recorded at the well would provide useful information about the location of the waterfront as it approached the well. In contrast, the coarse grid solution suggests that the SP would be featureless at

the well (Figure 3.11). These results demonstrate the utility of the LGR modelling capability in our SP solver.

We next consider the modelling of faults. Figure 3.12 shows an example of the behaviour of SP across fault (at cross-section B; Figure 3.9). The fault shown in figure 3.12a is a sealing fault, so there is no flow across the fault. In the simulation model grid, there are therefore no NNCs across the fault. However, the fault is electrically conductive, so electrical current can flow across the fault. Consequently, the SP generated by flow on one side of the fault penetrates into the reservoir and bounding shales on the other side of the fault. These current fluxes are modelled using the NNCs generated by our SP solver. The results demonstrate the utility of the fault modelling capability in our SP solver.

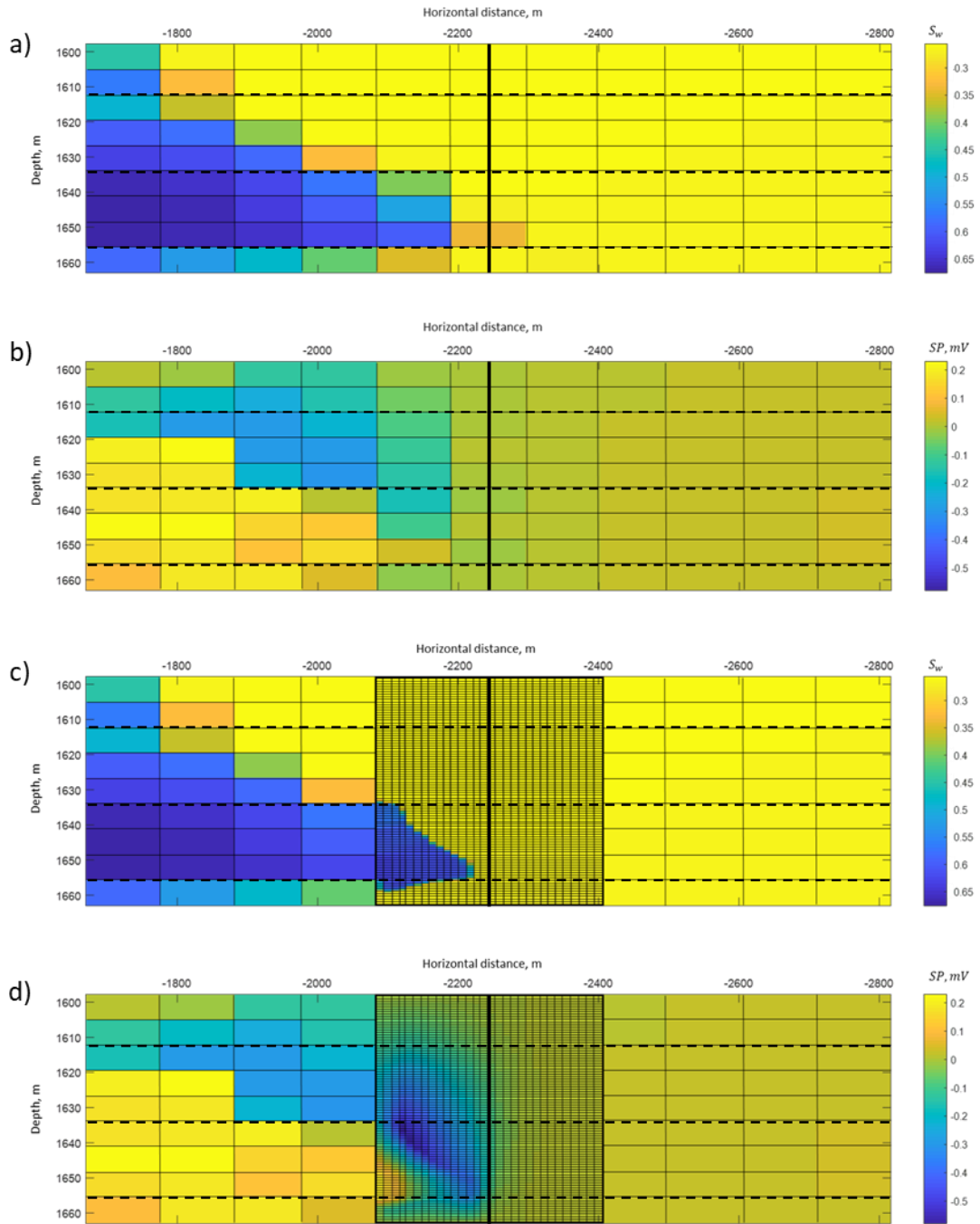


Figure 3.10: Vertical cross-sections along the plane A in Figure 3.9, showing a snapshot in time of (a) water saturation in the coarse model; (b) SP in the coarse model; (c) water saturation in the LGR model, and (d) SP in the LGR model. The dashed lines denote the four reservoir layers, and the solid line represents the production well BR-P-2.

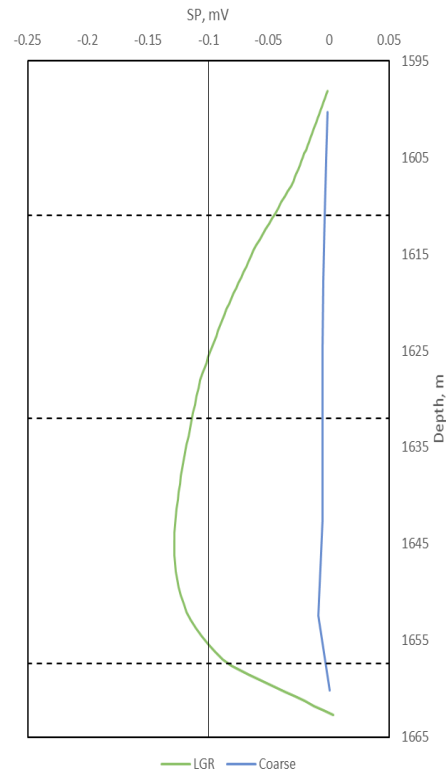


Figure 3.11: Predicted SP measured along the well from the coarse and LGR models. The dashed lines denote the four reservoir layers, and the solid line represents an assumed noise level of 0.1 mV.

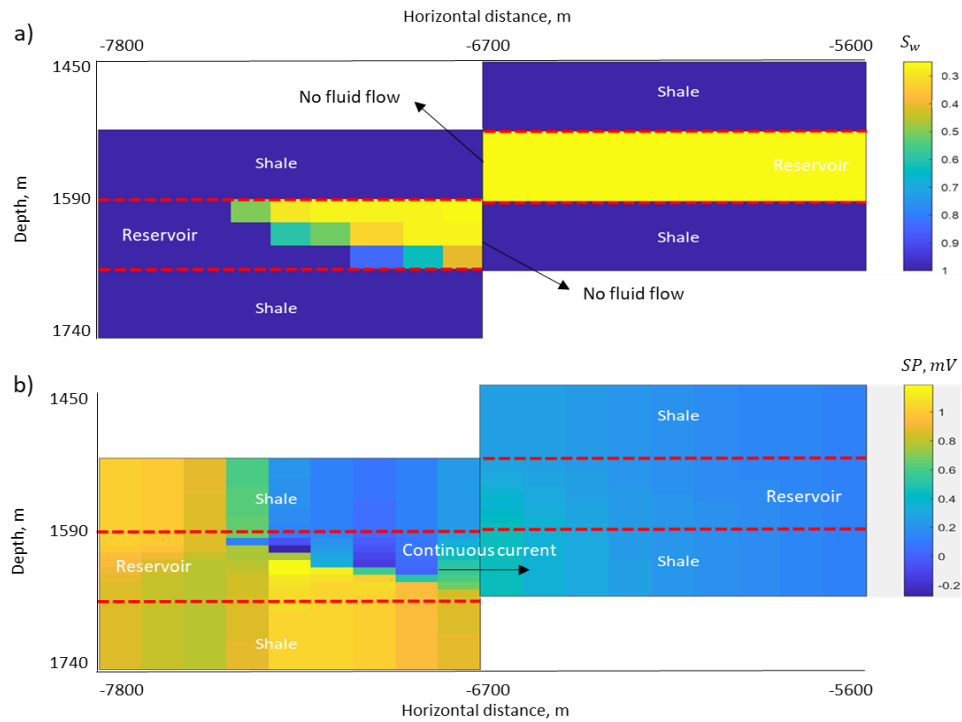


Figure 3.12: Vertical cross-sections along the plane B in Figure 3.9, showing a snapshot in time of (a) water saturation and (b) SP across the fault. The dashed lines denote the reservoir layers. There is no fluid flow across the fault, but there is current flow, so the SP generated by flow on one side of the fault penetrates into the reservoir and bounding shales on the other side of the fault.

It has been proposed previously that monitoring of SP at a production well can allow detection and tracking of moving waterfronts in an oil reservoir (Gulamali et al., 2011; Saunders et al., 2012). We finish by using the SP solver to test this proposal in the Brugge field model. We focus on the BR-P-2 production well (Figures 3.9–3.11). The well produces at a constant oil rate of 10000 STB/d, mainly from the bottom interval, for ca. 2160 days. After that, water breaks through at the well, so the well starts to produce water and the oil production rate starts to drop. The dynamic simulation indicates that the water approaches the well in the lowermost Waal stratigraphic interval. However, this is unlikely to be known in the reservoir.

Figures 3.13–3.15 show snapshots of simulated EK and ED components of the SP, and the total SP, in the vertical cross-section A (Figure 3.9) and at the production well. The TE component was also modelled but is not shown because its relative contribution to the SP is negligible, consistent with previous studies (Gulamali et al., 2011; Jackson et al., 2012b). Figure 3.13 shows results 45 days before

water breakthrough when the waterfront is ca. 40 m away from the well and salinity front is more than 200 m away. The resulted SP signal at the production well is less than the assumed noise level (Chen et al., 2006; Jackson et al., 2012b). The SP is dominated by the EK component that arises in response to the flow of water towards the well.

Figure 3.14 shows results 15 days before water breakthrough, when the waterfront is ca. 20 m away from the well, but the salinity front is still distant. The SP signal at the production well is higher than the assumed noise level and the SP maximum is skewed toward the lowermost Waal interval, within which the water is flowing. The SP is still dominated by the EK component. At water breakthrough (Figure 3.15), the maximum SP signal at the well is clearly aligned with the location of water breakthrough into the well and is still dominated by the EK component.

These results support earlier work that has suggested moving waterfronts in oil reservoirs can be detected and monitored by measuring SP in production wells using permanently installed downhole electrodes that are in electrical contact with the reservoir and are electrically isolated from any metallic well components (e.g. Saunders et al., 2008; 2012; Gulamali et al., 2011; Jackson et al., 2012b). In the example model tested here, the SP signal at the production well of interest exceeds the assumed noise level of 0.1 mV around 25 days before water breakthrough (Figure 3.16), and the maximum SP signal is located in the stratigraphic interval through which the water is flowing towards the well (Figure 3.14). Thus, the SP signal indicates an encroaching waterfront and identifies its location. These data can be used in reservoir management: for example, water production could be delayed or prevented by closing off production from the offending layer using inflow control valves (e.g. Dilib and Jackson, 2013; Dilib et al., 2015).

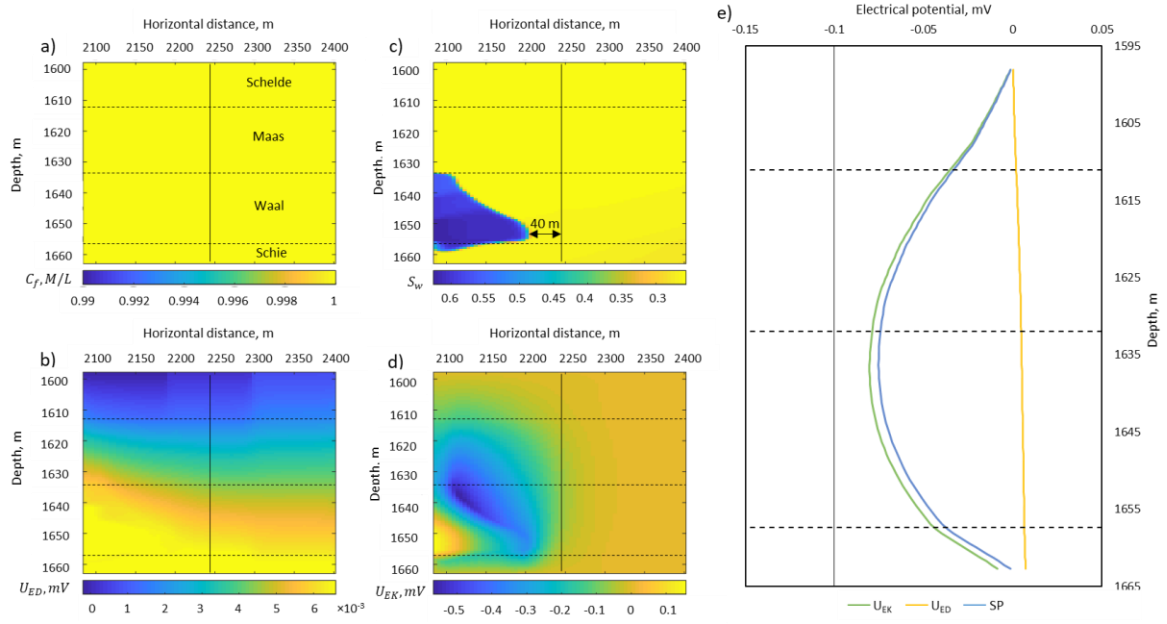


Figure 3.13: Vertical cross-sections along the plane A in Figure 3.9, showing a snapshot in time 45 days before water breakthrough at the production well, of (a) salt concentration; (b) ED potential; (c) water saturation, and (d) EK potential. The dashed lines denote the four reservoir layers, and the solid line represents the production well BR-P-2. Plot (e) shows the predicted EK, ED and SP along the well. The dashed lines denote the four reservoir layers, and the solid line represents an assumed noise level of 0.1 mV.

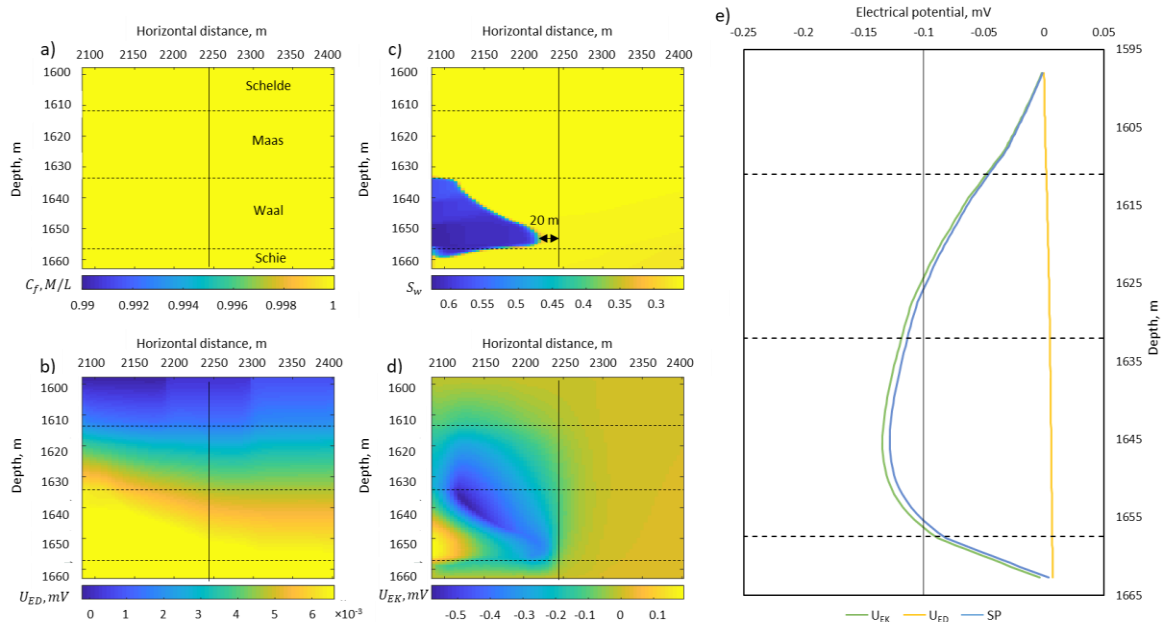


Figure 3.14: Vertical cross-sections along the plane A in Figure 3.9, showing a snapshot in time 15 days before water breakthrough at the production well, of (a) salt concentration; (b) ED potential; (c) water saturation, and (d) EK potential. The dashed lines denote the four reservoir layers, and the solid line represents the production well BR-P-2. Plot (e) shows the predicted EK, ED and SP along the

well. The dashed lines denote the four reservoir layers, and the solid line represents an assumed noise level of 0.1 mV.

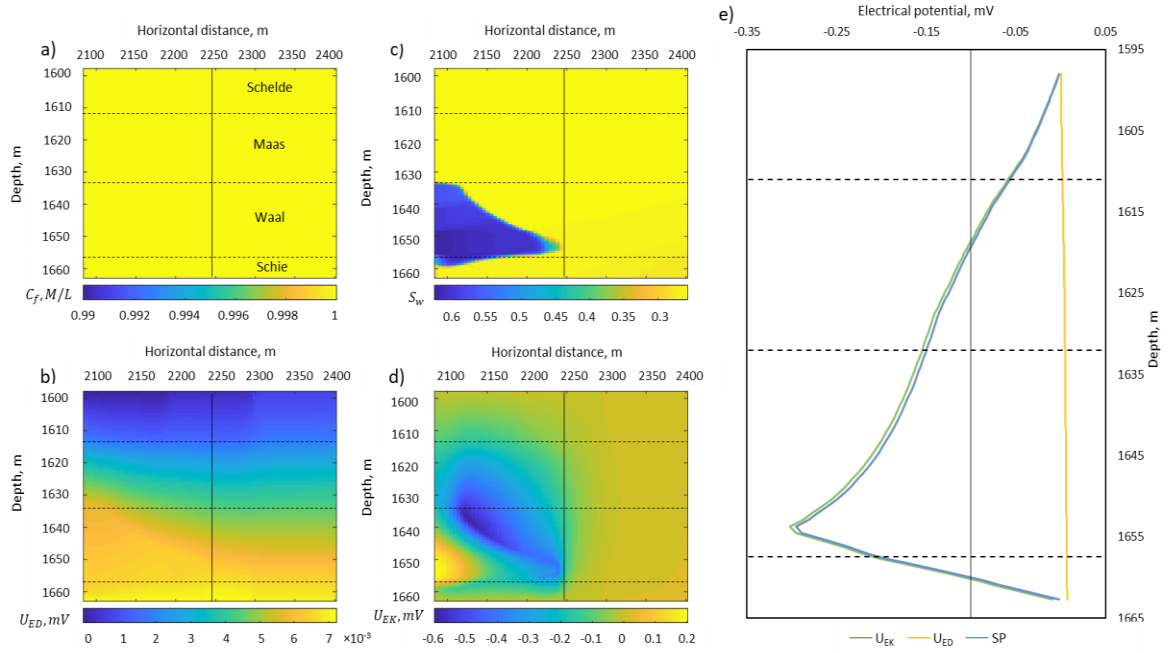


Figure 3.15: Vertical cross-sections along the plane A in Figure 3.9, showing a snapshot in time at water breakthrough, of (a) salt concentration; (b) ED potential; (c) water saturation, and (d) EK potential. The dashed lines denote the four reservoir layers, and the solid line represents the production well BR-P-2. Plot (e) shows the predicted EK, ED and SP along the well. The dashed lines denote the four reservoir layers, and the solid line represents an assumed noise level of 0.1 mV.

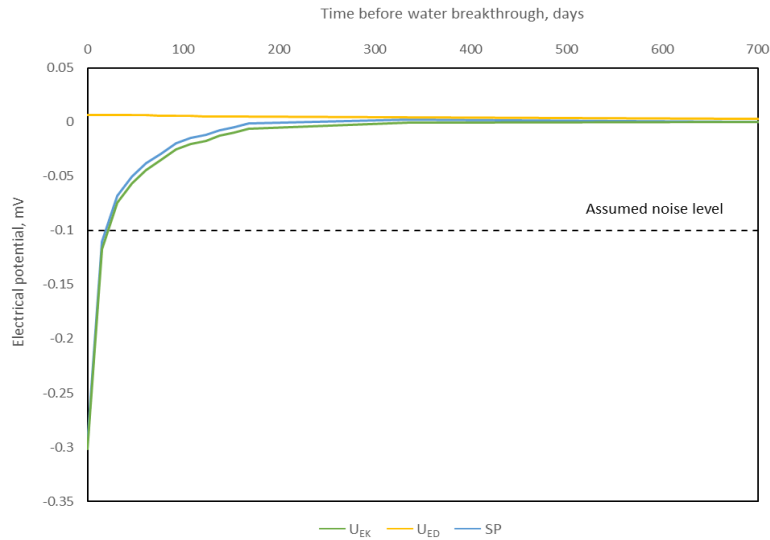


Figure 3.16: Maximum EK potential, ED potential and SP at the modelled production well BR-P-2 as a function of time before water breakthrough.

3.5 Conclusions

We report a new, open-source, MATLAB-based code for numerically simulating the SP in subsurface reservoirs. The code works as a post-processor, using outputs from existing reservoir flow and transport simulators at a selected timestep to calculate the SP throughout the reservoir model. The material properties required to calculate the SP are user-defined and may be constant or vary in each cell. The code solves the equations governing flow and transport of electrical charge and global charge conservation using a control-volume-finite-difference scheme.

We implement a new approach to calculate the current fluxes across grid-cell boundaries that can account for changes in polarity of the SP coupling coefficients. Electrical currents associated with the SP may spread beyond the reservoir model domain, and the code allows for the domain to be extended vertically and laterally to account for this. Accurate modelling of the SP may require locally fine grid resolution, and the code allows the use of local grid refinement in the reservoir flow or transport simulator and in the modelling of SP. Many subsurface reservoirs include faults, and the code allows the use of faulted grid, generating NNCs as necessary to model current flow across the fault. These NNCs may differ from those created in the reservoir flow or transport simulator, because the fault may act as a barrier to fluid flow or salt transport but not as a barrier to electrical current.

We demonstrate that the SP solver produces accurate SP solutions for both single- and multi-phase flow in a series of test cases and then demonstrate its utility in predicting the SP signal that would be measured at a production well during oil production from a faulted sandstone reservoir bounded above and below by shales. The results suggest that downhole SP monitoring could be useful to identify and locate moving waterfronts in the reservoir.

Chapter 4

Overview of Greater Burgan Reservoir

4.1 Introduction

The field considered for the feasibility assessment in this study is the Greater Burgan oil field located in Southeast Kuwait. This field is classified as the second largest field in the world, and it produces from the largest clastic reservoir in the world, encompassing a total surface area of 800 km² (Ma et al., 2014; Su et al., 2011). The geological structure of the reservoir consists of three main anticlines that divide the giant field into three chief producing areas: Burgan, Ahmadi and Magwa (Kirby et al., 1998; Figure 4.1). The field comprises two main reservoir units: Wara sand (top) and Burgan sand (bottom). A shale layer called Ahmadi is located on the top of the structure and acts as caprock. A water aquifer (Shu'aiba formation) underlies the Burgan sands and provides a bottom and edge water drive to the overlaying layers (Kirby et al., 1998; Table 4.1). Wara and Burgan sands are separated by a tight carbonate layer known as Mauddud.

The Burgan oil field was discovered in 1938 and has more than 70 years of production. Most of the field is still under primary production by depletion drive with the support from Shu'aiba aquifer. Burgan sand is divided into three sub layers, namely, Burgan sand upper (BGSU), Burgan sand middle (BGSM) and Burgan sand lower (BGSL). BGSL (bottom reservoir unit) is the thickest unit, and it directly lies over the Shu'aiba aquifer. This unit has been swept by the bottom water drive over the past years of production, and therefore, the remaining reserves in this layer are limited (Kirby et al., 1998). The second main reservoir unit is BGSM. The thickness of this unit is approximately 60 to 90 ft, and it is the main contributor to the overall production of Greater Burgan. BGSM has a good edge water drive at the flank area of the structure. BGSL and BGSM have excellent rock quality with permeability values up to 10000 md in the crustal area (Kirby et al., 1998). After that comes the BGSU, which is more heterogeneous and less continuous compared to bottom layers. This unit is also supported by an edge water drive, but the pressure support is weaker in comparison to BGSM because of the reservoir

heterogeneity. Mauddud Limestone overlies Burgan units and separates them from the next main reservoir unit, which is Wara sand. Likewise, Wara sands has three sub layers, namely lower, middle and upper, with the best rock quality found in the middle part. Wara reservoir unit has limited pressure support from the edge water drive at the flank area. At present, Wara sand is producing with the support of water injection at the flank area of the reservoir due to the faster depletion at the flank compared to the crustal area (Carr et al., 1998).

Greater Burgan is a super-giant field that comprises several prolific thick reservoir units. Therefore, the first major challenge was to select appropriate location and reservoir unit for conducting our SP feasibility study. BGSL was directly excluded because it is already swept by the bottom water drive. The other subunits are all suitable for the study; however, BGSU was selected because it is considered for water flooding in the near future and has the most updated geological model capturing the fine structural and petrophysical details (Muhammad et al., 2015a).

Next sections will furnish an overview of BGSU unit with regard to properties, rock typing, production performance and fluid properties. We will also prepare and discuss dynamic models representing different production scenarios, which will be used in Chapter 7 for SP modelling. Furthermore, we will discuss the selection and preparation process of the core plugs, which will be used for the experimental work in Chapters 5 and 6.

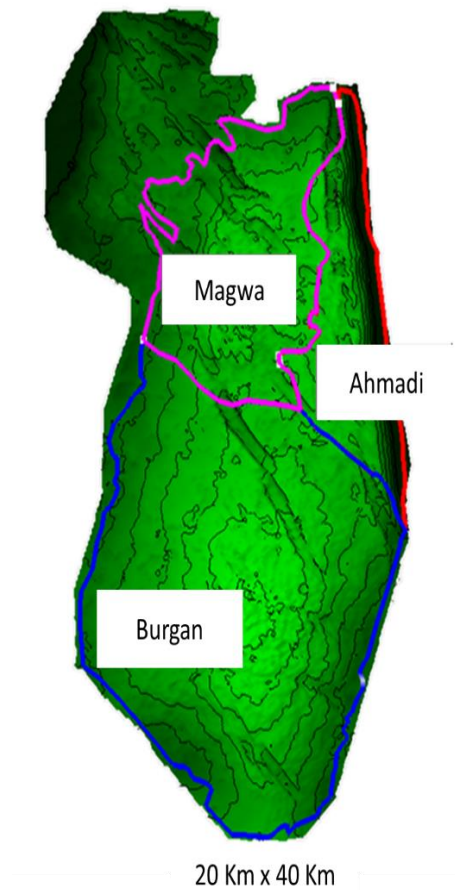


Figure 4.1: Greater Burgan field (Ma et al., 2014).

Table 4.1: Stratigraphic layers in Greater Burgan field.

Stratigraphic layer	Sub-layer	Description
Ahmadi		Shale, caprock
WARA	Upper (WASU)	High heterogeneity
	Middle (WASM)	Clean sand
	Lower (WASL)	Sand channels in shale
Mauddud		Tight limestone
Burgan	Upper (BGSU)	High heterogeneity
	Middle (BGSM)	Clean, thick sand
	Lower (BGSL)	Heavier oil
Shu'aiba		Aquifer

4.2 Burgan Upper Sand

BGSU reservoir is a clastic reservoir deposited after the massive BGSM reservoir. It belongs to Cretaceous age and is separated from the overlaying Wara reservoir by a carbonate layer Mauddud (Ortegon et al., 2015; Muhammad et al., 2015b; Table 4.1). The reservoir is composed of three subunits, namely BU1, BU2 and BU3, from top to bottom. The first two subunits are usually lumped together for most analysis and named BU1/2, while the lattermost is typically handled separately. This is because BU3 has better rock quality and holds the majority of hydrocarbons in BGSU (Ortegon et al., 2015; Muhammad et al., 2015b). BU1 and BU2 are more heterogenous, shaly and lower-quality layers. Porosity values are very good ranging from 10% to 35% in the best locations, whereas the permeability

ranges from few hundred millidarcies to few darcies in the crustal area (Ortegon et al., 2015; Muhammad et al., 2015b). Generally, the reservoir rock quality is the best Southwest of the field, and it decreases as we move towards the Northeast.

Most of the production from BGSU comes from the lower unit (BU3), which has been specifically targeted, especially in areas where there is good communication with the underlying BGSM. However, owing to its low rock quality and high heterogeneity in comparison to BGSM, it is being considered for water flooding to improve the recovery.

4.3 Type Area Approach

Given the size of the field and the level of complexity and heterogeneity in BGSU, it is impractical and time- and memory-consuming to execute the feasibility assessment on the full field scale. A better alternative is to conduct the study for small sectors that cover different parts of the reservoir and capture a high level of geological details. For this purpose, Muhammad et al. (2015a, b) developed high-resolution geological part field models, which they used to assess water flooding in BGSU. They developed three sector models or as they refer to as 'type areas', which represent different parts of the reservoir. The three areas were classified on the basis of i) the average reservoir rock quality of the BU3 and ii) the connectivity between the BU3 and the uppermost unit of BGSM. The average shale volume in the full BU3 package was used to account for the rock quality in BU3, while the average shale volume in the lowermost 20 ft of BU3 was used to account for the connectivity with BGSM. The three types of areas are referred to as high-connectivity area (HCA), moderate-connectivity area (MCA) and low-connectivity area (LCA) (Figure 4.2). Table 4.2 depicts the main difference between these areas.

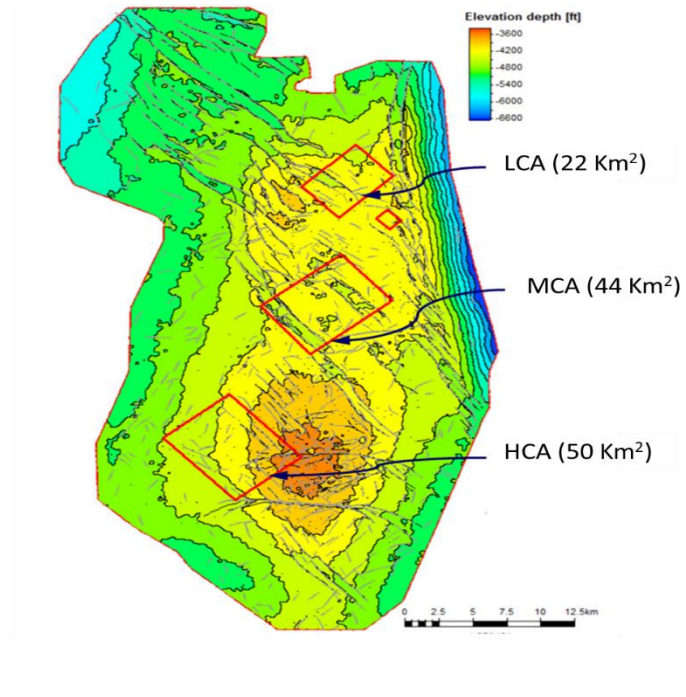


Figure 4.2: Greater Burgan field with highlighted locations of HCA, MCA and LCA sector models (Muhammad et al., 2015a).

Table 4.2: Characterisation of the three types of areas (Muhammad et al., 2015a).

Parameter	HCA	MCA	LCA
Shale volume	Low	Moderate	High
RFT $\Delta P/L$	Low	Variable	High
Spatial continuity	Good	Moderate	Poor
KH from pressure transient analysis	Consistently high	Variable	Consistently low

4.4 Production Performance of BGSU

We performed a quick assessment of the production performance of the wells currently completed across BGSU. This was accomplished by comparing the production rate and pressure drawdown for these wells. As expected, because of the high heterogeneity, we found noticeable diversity in the rates and pressure drawdowns and, therefore, in the productivity index. Production rates vary from few hundreds bbl/d to 3000 bbl/d (1 bbl = 0.159 m³), while pressure drawdown varies from 20 psi (137895 Pa) to 1000 psi (689475 pa). Productivity index reaches up to 70 bbl/d/psi (1 bbl/d/psi = 2.67×10^{-10} m³/s/Pa) in the sweet spots. Figure 4.3 illustrates the productivity index across the field. The decreasing

trend of the productivity index as we move from southwest to northeast is consistent with the fact the rock quality decreases in the same direction.

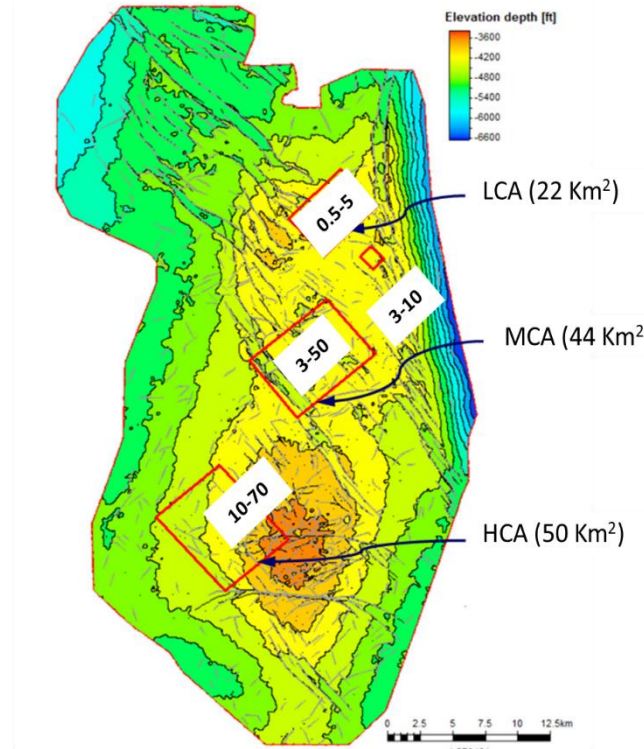


Figure 4.3: Productivity index (STB/d/psi) across the BGSU.

4.5 Rock Types

A comprehensive assessment of all the available special core analysis (SCAL) data was conducted by the operating company and resulted in characterising the reservoir rocks into six rock types (Table 4.3). The rock type classification is based on a calculated index referred to as rock quality index 'RQI', mathematically defined as follows:

$$RQI = 0.0314\sqrt{k/\phi} \quad (4.1)$$

where k and ϕ are the porosity and permeability.

Table 4.3: Rock types versus the RQI.

Rock type	RQI	Average porosity	Average permeability (md)
RT 1	0–0.25	0.1	1.5 (max = 20)
RT 2	0.25–0.60	0.16	20
RT 3	0.60–1.50	0.22	250
RT 4	1.50–2.40	0.27	1000
RT 5	2.40–3.60	0.30	2500
RT 6	3.60–10.00	0.31	6000

Physically, the RQI represents a measure of the average pore size in the rock. For example, a high RQI corresponds to a rock with a large pore size. The RQI can be associated with the dimensionless Leverett J-function, as the term $\sqrt{k/\phi}$ also appears in the J-function formula, defined as follows

$$J(S_w) = \sqrt{\frac{k}{\phi}} \frac{P_c}{\sigma} \quad (4.2)$$

where P_c is capillary pressure and σ is interfacial tension. The dimensionless J-function can be used to group capillary pressure curves as it is assumed to be largely constant for rocks of the same topology, and it accounts for changes in pore size. Therefore, the RQI can also be used to group the capillary pressure curves and identify different rock types. Figure 4.4 shows all normalised capillary pressure curves used for assessment. As expected from a giant field, there is a wide scatter in the data. Figure 4.5 shows how the capillary pressures are grouped when normalised and is shown for different ranges of RQI. Obviously, this approach reduces the scatter in the data as compared to Figure 4.4. Therefore, this rock typing will be used in the next sections to assign the multiphase flowing properties for the dynamic simulation (relative permeability and capillary pressure).

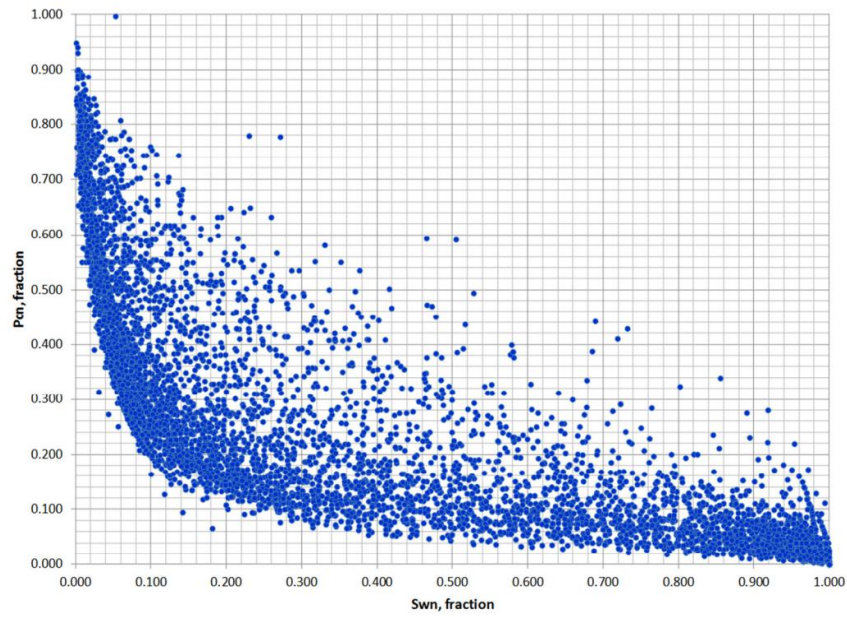


Figure 4.4: Normalised capillary pressure curves used for rock typing.

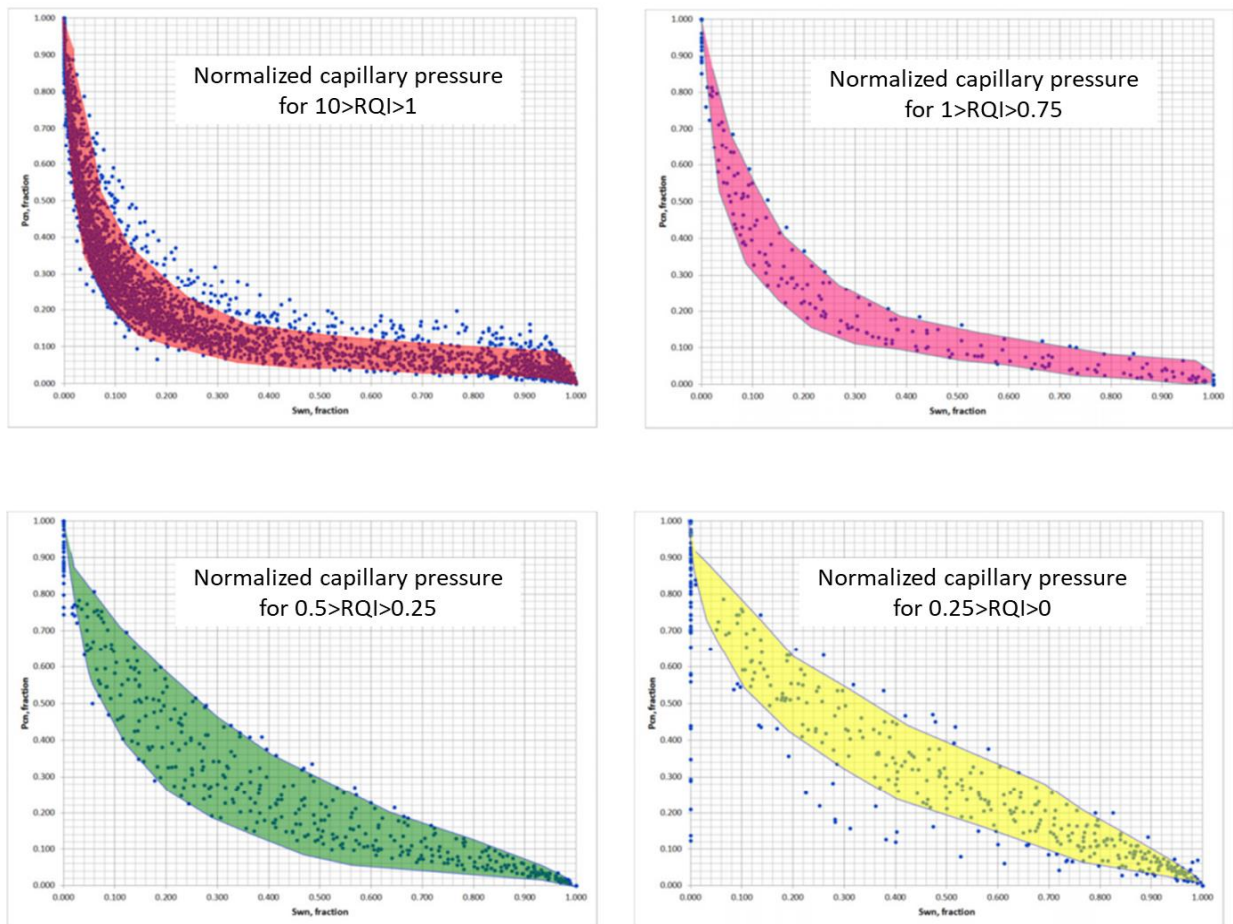


Figure 4.5: Grouped capillary pressure curves based on RQI. Coloured polygons mark a variability band around the main trends.

4.6 Relative Permeability and Pressure–Volume–Temperature Data

Experimental relative permeability data are widely scattered, and thus, they were split in accordance with the rock type in the same manner followed in Section 4.5, as shown in Figure 4.6. The experimental data were used to identify the end points (Table 4.4), which were used to generate relative permeability curves using Corey correlation. Experimental relative permeability data, with the generated relative permeability models are shown in Figures 4.6 and 4.7.

Summary of the pressure–volume–temperature (PVT) data is presented in Figure 4.8. The bubble point pressure is 1732 psi. The PVT data together with the relative permeability curves will be used as inputs for the dynamic simulations carried in subsequent sections.

Table 4.4: Relative permeability data.

Rock type	Critical water saturation	Residual oil saturation	Initial water saturation	End-point water relative permeability	End-point oil relative permeability	Corey exponent, water	Corey exponent, oil
1	0.45	0.19	0.45	0.25	0.35	2	2.5
2	0.37	0.19	0.37	0.25	0.35	2	2.5
3	0.29	0.19	0.27	0.25	0.85	2	2.5
4	0.17	0.19	0.17	0.25	0.85	2	2.5
5	0.11	0.19	0.09	0.25	0.85	2	2.5
6	0.09	0.19	0.08	0.25	0.85	2	2.5

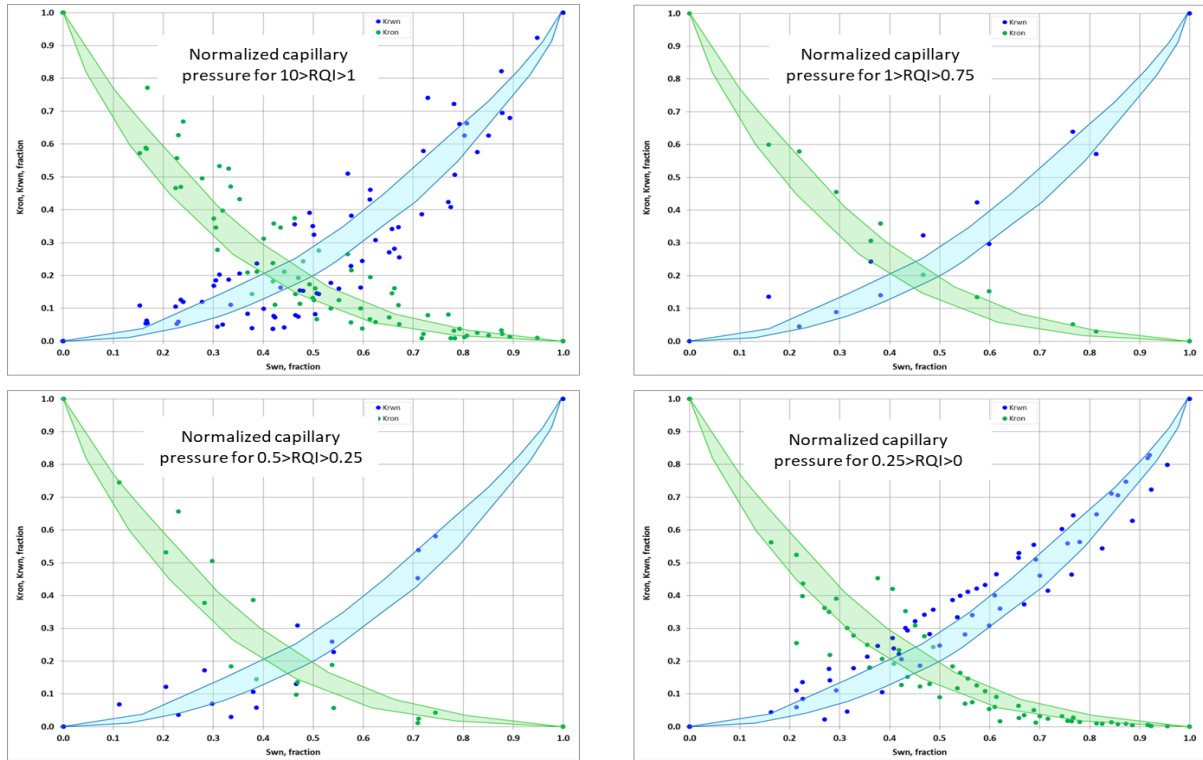


Figure 4.6: Normalised water-oil relative permeability data for different rock types. Shaded areas mark a variability band around the main trends.

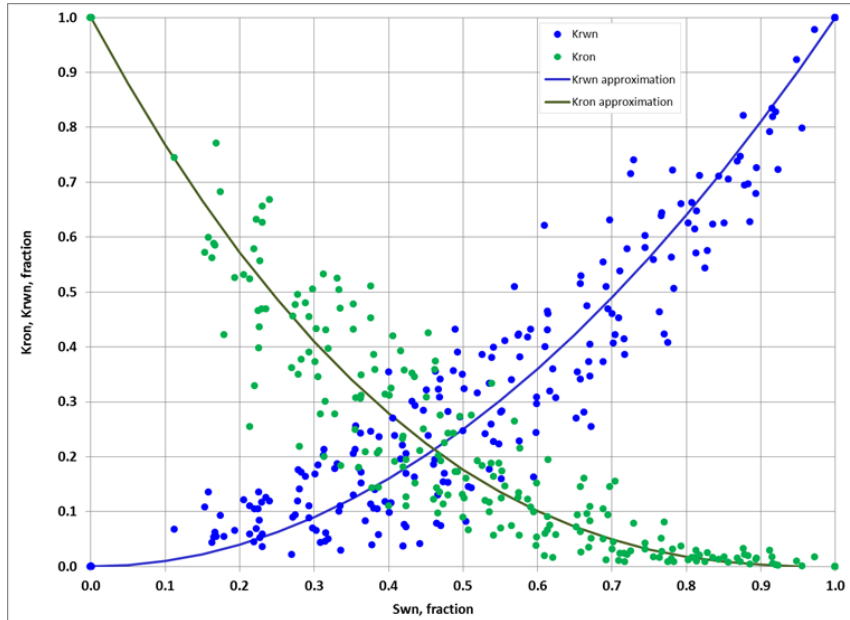


Figure 4.7: Normalised water-oil relative permeability curves from Corey correlation (solid lines) overlaid with core data points for all rock types.

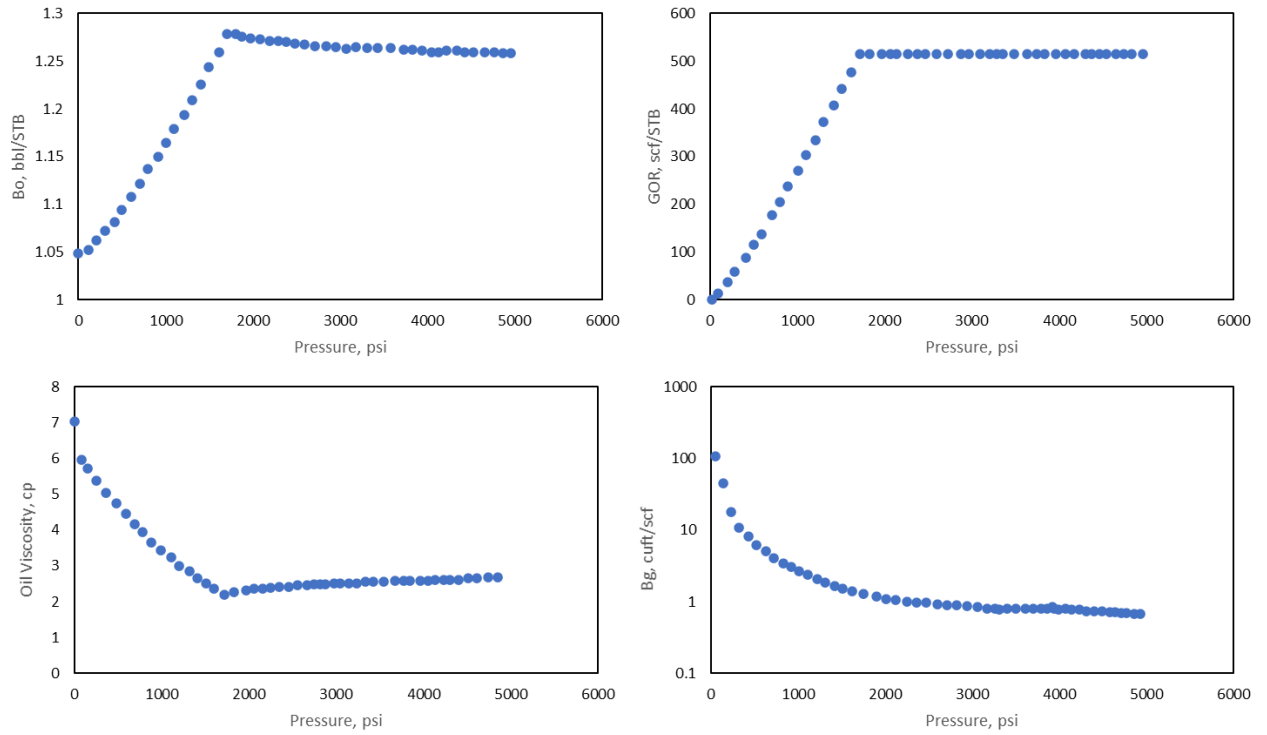


Figure 4.8: PVT data for BGSU oil.

4.7 Dynamic Simulation

Among the three sector models (LCA, MCA and HCA), we decided to perform analysis on the LCA model as it is almost hydraulically isolated from the underlying layer (BGSM) and can be produced without any interference with other reservoir sections in this specific area. We used the ECLIPSE 100 reservoir simulator to execute the dynamic simulation. Six saturation regions were defined using the ECLIPSE keyword SATNUM in accordance with the rock typing accomplished in Section 4.5. Next, PVT, relative permeability and capillary pressure data described in previous sections were incorporated into the model. Rock types 1 and 2 were considered as non-reservoirs because of their low permeability and high shale content in comparison with the other rock types, and therefore, they were deactivated. The production scenario that we considered involved adding 12 production wells and 20 injection wells following a five-spot pattern and 500 m spacing (Figure 4.9). Pressure and rate limitations considered for the modelling are shown in Table 4.5. The flowing bottom-hole pressure was limited to 1750 psi (bubble point pressure) to avoid having three phases in the reservoir. All the wells are vertical wells

with selected perforated intervals of the highest flow capacity (permeability (k) $\times$ thickness (h)). We considered running the model for six years until water breaks through in all productive zones in all wells. Figure 4.10 shows the field cumulative oil and water production with time.

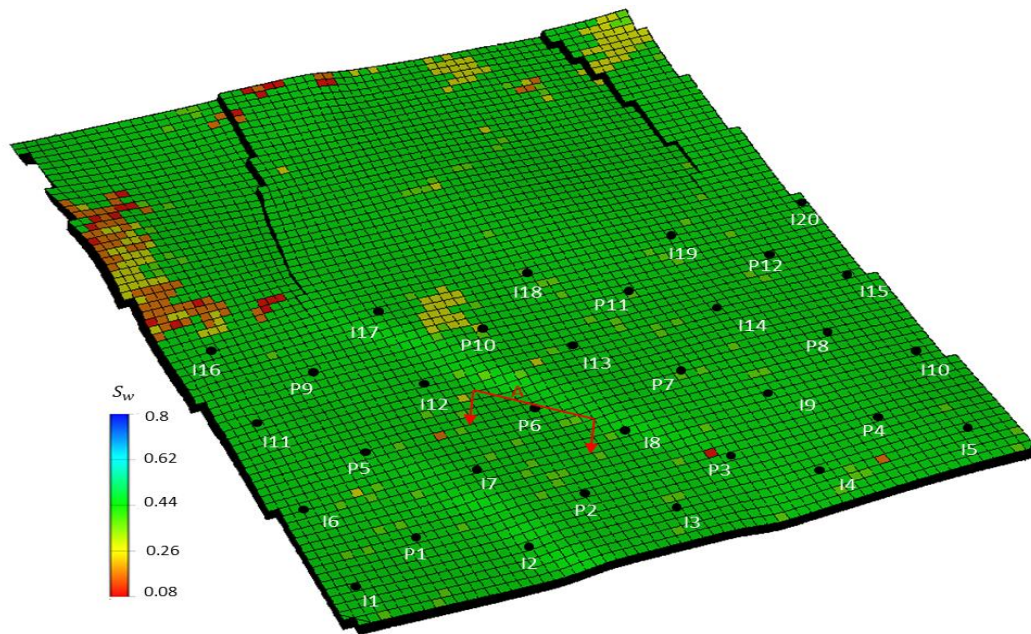


Figure 4.9: LCA sector model showing well distribution (P: production wells and I: injection wells). The model comprises 428130 grid blocks ($67 \times 71 \times 90$).

Table 4.5: Pressure and rate conditions for production and injection wells.

Production wells	
Liquid rate, STB/d	3000 (0.005 m ³ /s)
Minimum Flowing bottom hole pressure, psi	1750 (12 MPa)
Injection wells	
Injection rate, STB/D	1800 (0.003 m ³ /s)
Maximum Injection pressure, psi	2500 (17.2 MPa)

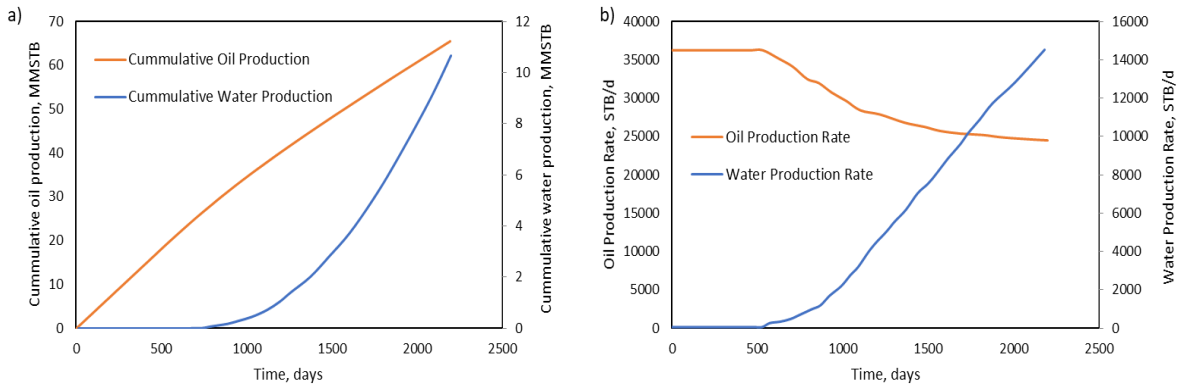


Figure 4.10: a) Field cumulative oil and water production versus time. b) Field oil and water rate versus time.

There was no attempt for quantitatively history matching the model, but it should behave in a reasonably consistent manner to the reservoir of interest. Herein, we used the productivity index as an indicator to compare well performance from the model with the actual data. Figure 4.11 shows the liquid and water production rates, reservoir pressure and flowing bottom-hole pressure for well P6 (Figure 4.9). This well has been completed across three intervals: A, B and C as shown in Figure 4.12. The well produced 3000 STB/d of oil with a pressure drawdown of 400 psi Figure (4.11b), which corresponds to a productivity index of 7.5 STB/d/psi. This productivity index value is consistent with what is observed in the field (Figure 4.3). The allocation of the production rates among the three intervals is shown in Figure 4.11c. The well continued producing 3000 STB/d of oil for 1150 days. Subsequent to that, it started to produce water from interval B, and within two months, intervals A and C started to produce water as well. These simulation results appear to be reasonable as they captured the key aspects required for SP modelling: i) water movement towards wells in multiple intervals and ii) near wellbore production performance. This model will be used in Chapter 7 for SP simulations. The results discussed in this section represent the base-case scenario, with a target rate of 3000 STB/d and five-spot water injection pattern (500 m well spacing) considering reinjecting formation water. More scenarios obtained by changing the production rates, well spacing, completion scheme and salinity of the injected water will be discussed in Chapter 7.

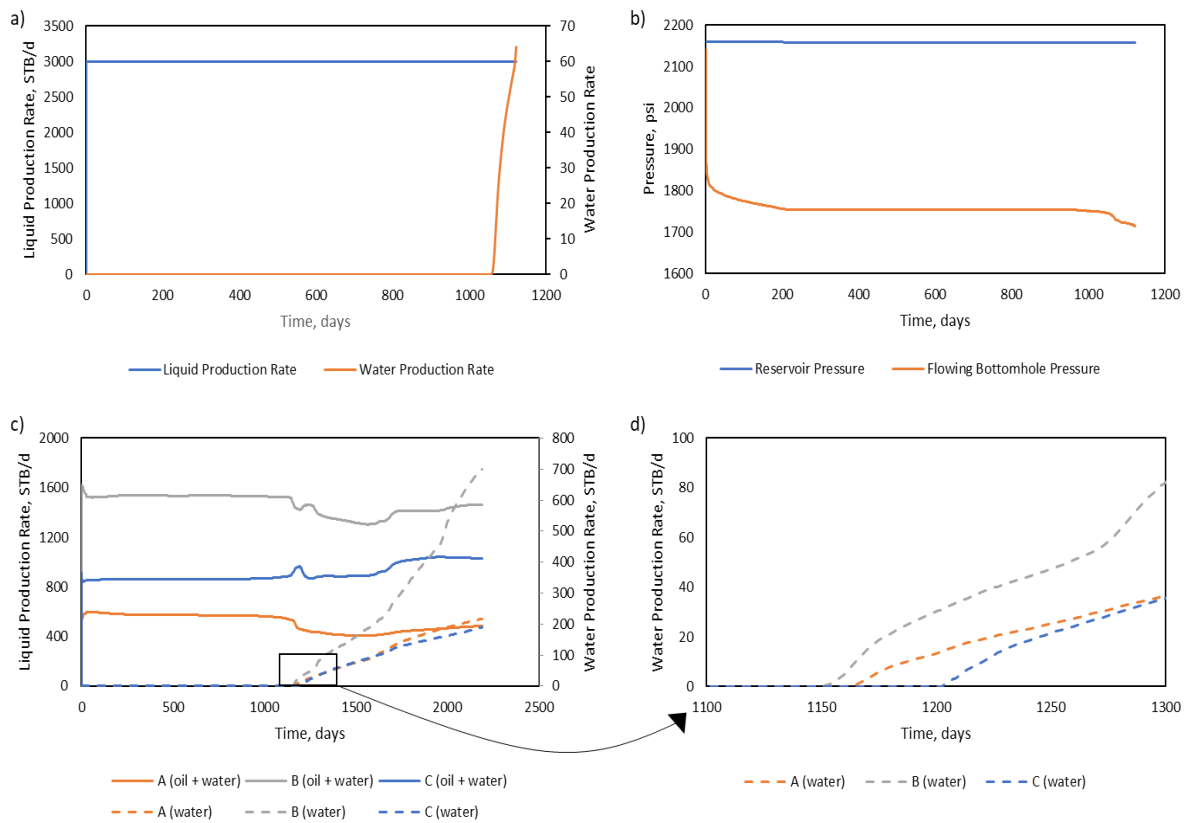


Figure 4.11: Production figures for well P6. a) Liquid and water production rates versus time. b) Reservoir pressure and flowing bottom-hole pressure versus time. c) Liquid and water production rates versus time for intervals A, B and C. d) Water production rates versus time for intervals A, B and C.

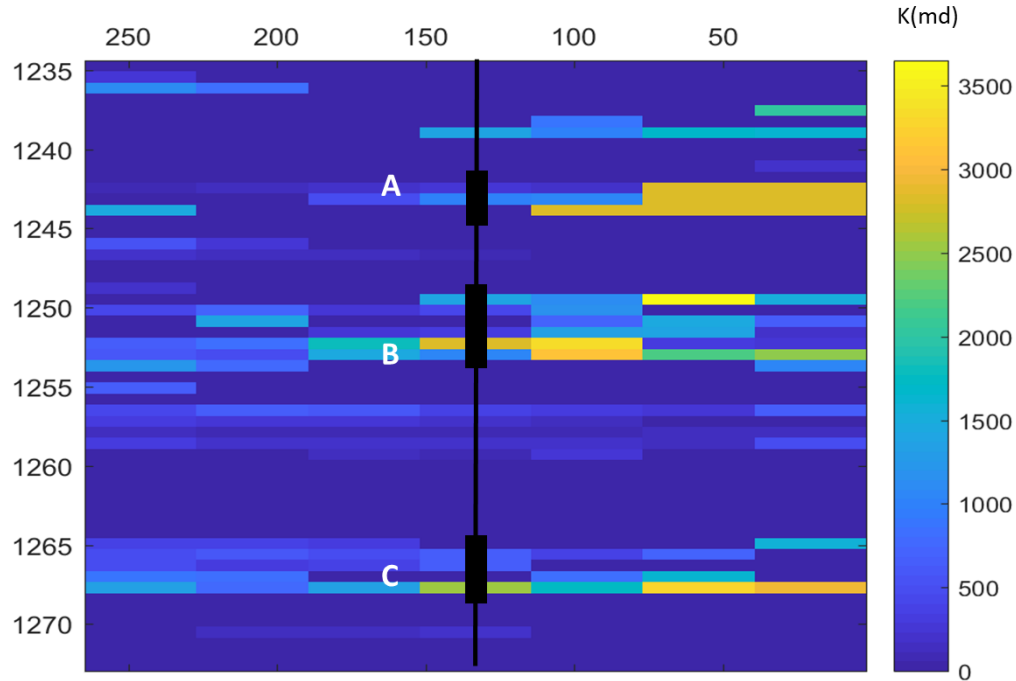


Figure 4.12: Vertical cross-section along with Plan A in Figure 4.9, showing permeability. The vertical solid line denotes the well. The three perforated intervals (A, B and C) are highlighted with black rectangular boxes.

4.8 Fluid Sampling and Core Plug Selection for the Experimental Work

4.8.1 Fluid samples

Wellhead oil samples (specific gravity = 0.92) were collected from a well producing from BGSU. Synthetic formation brine (FMB) was made using de-ionised water (resistivity of 16 M Ω .cm) and reagent grade salts based on a water composition report provided by the operating company (Table 4.6). We also prepared lower salinity brines (diluted FMBs, seawater and 40 times diluted seawater) to be used for low salinity water core flood (Table 4.6).

Table 4.6: Composition of the brines used in this study.

Salt	FMB ¹	FMB - Dilution 1	FMB - Dilution 2	FMB - Dilution 3	SW ²	DSW ³
Sodium Chloride (NaCl), M/L	1.850	1.260	0.840	0.280	0.420	0.0105
Potassium Chloride (KCl), M/L	0.037	0.025	0.016	0.0057	0.010	0.00025
Magnesium Chloride hexahydrate (MgCl ₂ .6H ₂ O), M/L	0.087	0.059	0.039	0.013	0.054	0.00135
Calcium Chloride (CaCl ₂), M/L	0.220	0.15	0.1	0.034	0.010	0.00025
Sodium Bromide (NaBr), M/L	0.0066	0.0045	0.003	0.001	-	-
Sodium Sulfate (Na ₂ SO ₄), M/L	-	-	-	-	0.028	0.0007
Sodium bicarbonate (NaHCO ₃), M/L	-	-	-	-	0.002	0.00005
Total, M/L	2.200	1.5	1	0.5	0.520	0.013

¹: Formation brine

²: Seawater

³: 40 times diluted seawater

4.8.2 Rock samples

The rock samples were meticulously selected to represent the different rock types of BGSU. Table 4.7 shows a summary of 23 collected core plugs. Note that we could not obtain plugs of rock type 6. The samples are cylindrical with a diameter of 3.7 cm.

The first screening criterion was the dimension of the core. Minimum core length required for running EK and ED experiments is 4.0 to 5.0 cm. Therefore, any core that is shorter than that was directly eliminated (examples are shown in Figures 4.13 and 4.14). The second screening criterion was the integrity of the core surface, which was accomplished by investigating the samples for any broken edges or very rough surfaces (examples are shown in Figures 4.15 and 4.16). The last step was to run dry

computerized tomography (CT) scans for the core plugs that passed the first and second screenings to check the internal integrity and fractures. We eliminated the samples that showed evidence of fractures under the CT scan (examples are shown in Figures 4.17 through 4.22). As a result of this screening process, 10 samples were eliminated, and 13 rock samples were selected to proceed with the experimental work. A concise summary of the core selection process is presented in Table 4.7.

Table 4.7: Summary of the core selection process.

Rock type	Sample number	Condition	Comment
RT 1	1	✓	
	2	X	Short length
	3	X	Fractures
	4	✓	
	5	✓	
	6	✓	
RT 2	7	✓	
	8	✓	
	9	X	Fractures
	10	✓	
RT 3	11	X	Broken edges
	12	X	Broken edges
	13	X	Fractures
	14	✓	
RT 4	15	X	Fractures
	16	X	Fractures
	17	✓	
	18	✓	
	19	✓	
RT 5	20	✓	
	21	✓	
	22	x	Fractures
	23	x	Short length



Figure 4.13: Rock sample 2.

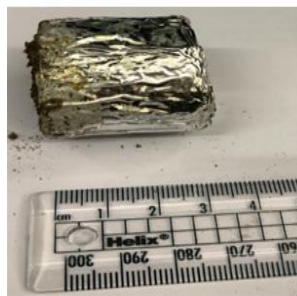


Figure 4.14: Rock sample 23.



Figure 4.15: Rock sample 11.

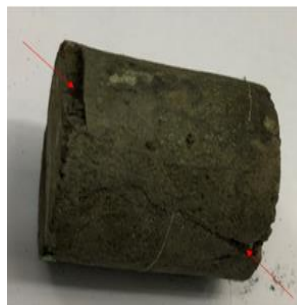


Figure 4.16: Rock sample 12.

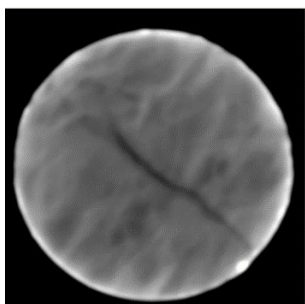


Figure 4.17: CT scan of rock sample 3.

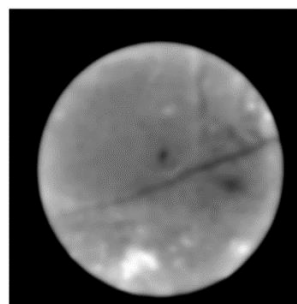


Figure 4.18: CT scan of rock sample 9.

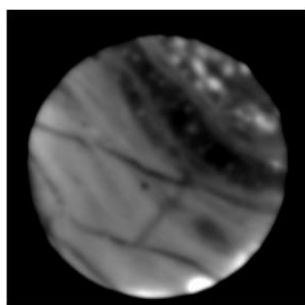


Figure 4.19: CT scan of rock sample 13.

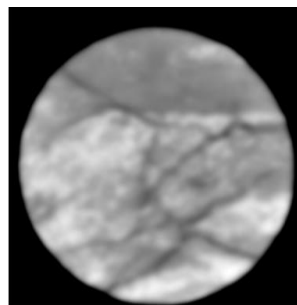


Figure 4.20: CT scan of rock sample 15.

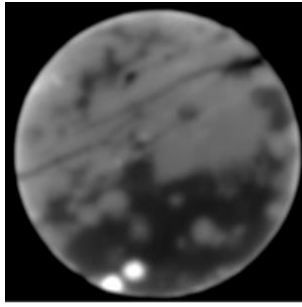


Figure 4.21: CT scan of rock sample 16.

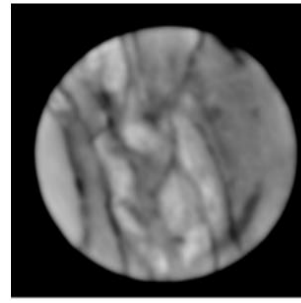


Figure 4.22: CT scan of rock sample 22.

4.8.2.1 *Rock samples' cleaning*

The 13 selected core plugs were then cleaned in a Soxhlet extractor using toluene and methanol, which were heated in the lower flask and allowed to evaporate (Figure 4.23). The rising vapour was directed into the condenser above the core sample chamber. The condensed solvent then ran into the core sample chamber until it reached an outlet at the top of the chamber, which allowed it to run back into the boiling flask. The process continued, considering regular replacement of the solvents in the lower flask, until we observed no colour change in the solvent (Collini et al., 2020). Four samples collapsed during the cleaning process, and therefore, the final core list shrunk to nine samples as shown in Table 4.8.

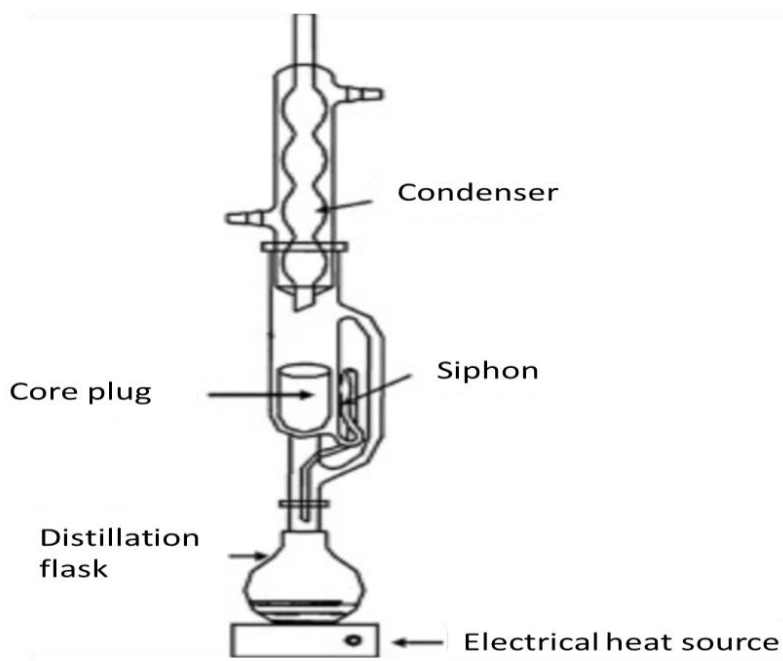


Figure 4.23: Soxhlet extraction unit (López-Bascón and de Castro, 2020).

Table 4.8: Final core plug list.

Rock type	Sample number	Sample reference ¹
RT 1	4	SH1
	5	SH2
RT 2	7	SH3
	8	SH4
	10	SH5
RT 3	14	SS1
RT 4	18	SS2
RT 5	20	SS3
	21	SS4

¹: In the remainder of this dissertation, we will refer to the sample according to this reference.

4.9 Summary

An overview of Greater Burgan oil field has been presented, outlining the factors that led to choosing BGSU as a target to conduct the SP feasibility study. We then presented a more detailed review of the BGSU layer with special emphasis on the production performance and rock types. It has been shown that BGSU is a highly heterogeneous layer comprising very clean sand channels imbedded in shale. Therefore, reservoir permeability is up to a few darcies in the clean sand.

A base-case dynamic model for BGSU was prepared in ECLIPSE simulator. This model comprised a production scenario with 12 production wells and 20 injection wells following a five-spot pattern, 500 m spacing and 3000 STB/d target production rate per well. The established model captured the key aspects of water movement towards production wells and behaved in a reasonably consistent manner to the reservoir of interest. This model will be used in Chapter 7 for modelling SP. More production scenarios will be considered in the study by changing the production rates, well spacing, completion scheme and salinity of the injected water.

The selection of rock and fluid samples and the preparation procedure for the experimental work (EK and ED experiments) were also discussed. Synthetic FMB, seawater, and diluted seawater were made in accordance with the water composition reports from the field itself, while the oil sample was collected from the wellhead of a well producing from BGSU. For the rock samples, 23 core cylindrical plugs were collected, out of which nine samples passed the screening and cleaning process. These nine samples will be used in Chapters 5 and 6 for the EK and ED experiments, respectively.

Chapter 5

Electrokinetic (EK) Potential Experiment

5.1 Introduction

The main objective of the EK experiment was to measure the EK coupling coefficients, which is one of the main inputs to the SP solver. In Chapter 3, we defined the EK coupling coefficient using an empirical correlation fitted through the published data of quartz-dominated sandstone samples saturated with NaCl brines. The published data discussed in Chapters 2 and 3 reported either the EK coupling coefficient or the zeta potential (function of EK coupling coefficient); there is an agreement that the coupling coefficient and the zeta potential of quartz-dominated sandstones are negative in the brine pH and compositions typically encountered in the subsurface and decrease in magnitude with increasing concentration. However, natural sandstones, like the Burgan sand, comprise quartz but also different types of clays, carbonates and other minerals and, in the subsurface, are often saturated with brines containing multiple, multi-valent ionic species at high concentration. The EK coupling coefficient in such systems has rarely been measured. Few studies have investigated the impact of divalent ions such as Ca^{+2} and Mg^{+2} , and these suggested that the coupling coefficient and zeta potential remain negative but become smaller in magnitude in the presence of divalent ions compared to pure NaCl (Mammen et al., 1997; Lorne et al., 1999; Coreño et al., 2001; Datta et al., 2009; Thanh and Sprik, 2016; Vinogradov et al., 2018; Li et al., 2018). Therefore, the EK coupling coefficient and zeta potential in complex natural rocks saturated with high concentration multi-ionic brines are still uncertain.

As the main target of this study is an oil reservoir, it is necessary to investigate the EK coupling coefficient at partial saturations. The current approach used in the SP solver to model the saturation dependence of EK coupling coefficient was described by Jackson et al. (2012b), and it assumed that the coupling coefficient is equal to zero at irreducible water saturation (minimum water saturation; $S_w = S_{wirr}$), equal to the coupling coefficient of a fully water-saturated rock at residual oil saturation (maximum water saturation; $S_w = 1 - S_{or}$) and vary between maximum and minimum saturations

according to equation 3.18. Jackson et al. (2012b) based their model on the limited number of two-phase experimental data, and therefore, the behaviour is still not fully understood, necessitating further characterisation.

This chapter aims to characterise the EK coupling coefficients for the sandstone samples (SS1, SS2, SS3 and SS4) of rock types 3, 4 and 5 as these are the rock types where water flow occurs, and hence, EK potential can be generated. First, we measured the EK coupling coefficients for the samples when fully saturated ($S_w = 1$) with FMB (containing multiple, multi-valent ionic species at high concentration as shown in Table 4.6) and compared the results with published data measured using pure NaCl brines and brines containing multi-valent ions. Second, we measured the EK coupling coefficient at residual oil saturation ($S_w = 1 - S_{or}$) and compared it against the values used in the SP solver. The characterisation of the EK coupling coefficient at $S_{wirr} \leq S_w < 1 - S_{or}$ is challenging (Vinogradov and Jackson, 2011), and there is no established experimental setup for that purpose. Therefore, we only reported the coupling coefficients at $S_w = 1 - S_{or}$. Besides the EK coupling coefficient, we measured the rock conductivity when fully and partially saturated with water. Rock conductivity is one of the key factors controlling the SP, and it is modelled in the SP solver using Archie's equation (equation 3.15). Thus, experimentally measured rock conductivity is also of great value for SP modelling.

5.2 Material and Methods

5.2.1 Core plug preparation

The four sandstone samples (SS1, SS2, SS3 and SS4) prepared and cleaned as described in Section 4.8.2 are used in this chapter to measure the EK coupling coefficients and rock conductivity. The basic rock properties are summarized in Table 5.1.

After cleaning, the samples were vacuum saturated with the brine of interest, prepared using de-ionised water (resistivity of 16 M Ω .cm) and reagent grade salts. The compositions of the brines used in this study are shown in Table 4.6. At that stage, the samples were ready to conduct the EK coupling coefficient measurements at $S_w = 1$ using the experimental procedures described in the next section.

To conduct the measurements at $S_w = 1 - S_{or}$, the cores were first saturated with FMB by displacing the last brine in each core (after the measurements at $S_w = 1$) using the core holder setup shown in Figure 5.1a (explained in the next section). Next, the cores were drained with crude oil (specific gravity = 0.92) to the irreducible water saturation ($S_w = S_{wirr}$) at a low rate (0.01 mL/min) and then aged, submerged in the same crude oil, for three weeks at 80°C. The samples were then flooded with the FMB until no oil flowed out of the core sample, and it was considered to have residual oil saturation ($S_w = 1 - S_{or}|_{FMB}$). The experimental procedures described in the next section were then used to measure the EK coupling coefficients. After that, the core samples were flooded with seawater (SW), and we kept reporting any additional oil recovery until no oil flowed out of the core sample, and it was considered to have new residual oil saturation ($S_w = 1 - S_{or}|_{SW}$). Then, we measured the EK coupling coefficients using the setup described in the next section. The final step was to flood the cores with 40 times diluted seawater (DSW) to recover any additional oil and bring the core to new residual oil saturation ($S_w = 1 - S_{or}|_{DSW}$) and then measure the coupling coefficients using the setup described in next section.

Table 5.1: Basic rock properties for the sandstone samples used in this study.

Sample	SS1	SS2	SS3	SS4
Porosity	0.17	0.22	0.25	0.23
Permeability, md	100	500	700	900
Dimension Length (cm) x Diameter (cm)	5.5 x 3.7	5.5 x 3.7	5.5 x 3.7	5.5 x 3.7

5.2.2 Experimental procedures

The EK coupling coefficient of each core sample was measured using the streaming potential method described by Vinogradov et al. (2010). The core plug, either at $S_w = 1$ or $S_w = 1 - S_{or}$, was placed inside a rubber sleeve then held in a PEEK core holder with PEEK end caps. At both ends of each core, there were fine and coarse nylon meshes used as a flow disperser. A confining pressure of 2 MPa was then applied by pumping gas through the purge opening in the core holder into the space between rubber sleeve and the inner surface of the core holder (Figure 5.1a). The confining pressure was kept several

hundred kPa higher than the pressure used in the experiments to avoid any fluid to flow between the rubber sleeve and the outer surface of the core plug. Figure 5.1a shows the core holder setup.

A Quizix QX-500 Stainless steel pump was used for inducing a fluid flow across the core plug from brine reservoirs (filled with the brine of interest) connected to either side of the core holder (Figure 5.1b). Synthetic non-polar oil (MULTIPAR-H) was used to translate the induced pressure from the pump to the brine in the reservoir. The use of synthetic oil allowed air bubbles in the brine to be captured at the top of the oil layer in each reservoir. It also prevented exposure of brines to atmosphere and reduced corrosion of the pump. The pump is capable of maintaining a constant rate to high accuracy, and the flow could be directed in either direction through the core plug by adjusting the flow valves (V_2 , V_3 and V_4 ; Figure 5.1b). Brine flow through the core plug was induced with the pump at a set flow rate, and the pressure drop (ΔP) and voltage drop (ΔV) were recorded once they reached a stable value. Pressure and voltage measurements were repeated at different flow rates to obtain a range of values for ΔP and ΔV . The direction of brine flow through the core was reversed, and the procedure was repeated to ensure no polarisation effects were present. The stabilised values of ΔV were then cross plotted against the corresponding stabilised ΔP values; the slope of the linear regression through the data gives the EK coupling coefficient (C_{EK} , e.g., Figure 5.2).

The pressure drop across the sample was measured using a pair of calibrated Druck PDCR 810 pressure transducers (accuracy 0.1% of the measured value, resolution 70 Pa; Figure 5.1b). The voltage drop (EK potential) across the sample was measured using two non-polarizing Ag/AgCl electrodes on either side of the core holder and a National Instruments NI9219 voltmeter (internal impedance $> 1 \text{ G}\Omega$, accuracy 0.18%, resolution 50 nV; Figure 5.1b). The electrodes were connected to the voltmeter using copper coaxial cables. The electrodes were placed out of the main flow path to avoid electrode flow effects (Figure 5.1b), and they were located in a brine reservoir (with internal NaCl concentration similar to the brine investigated), which was in electrical contact with the flowing brine via a low permeability ceramic disc (Figure 5.1c).

Another pair of electrodes was located at either end of the core sample and used to measure the saturated core conductivity. These electrodes consisted of a permeable AgCl membrane of the same diameter as

the core sample, connected via Ag rods through the PEEK end-caps (Figure 5.1a). The rock conductivity was measured using a QuadTech7600 precision LCR meter (over a frequency range of 10 Hz to 2 MHz) directly after measuring the EK potential for each brine. The setup facilitated fluid sampling through sampling points (V_6 and V_7 ; Figure 5.1b). The conductivity and pH of the used brine were measured on a regular basis using a Metrohm 712 conductivity meter and Mettler Toledo FiveGo pH meter, respectively.

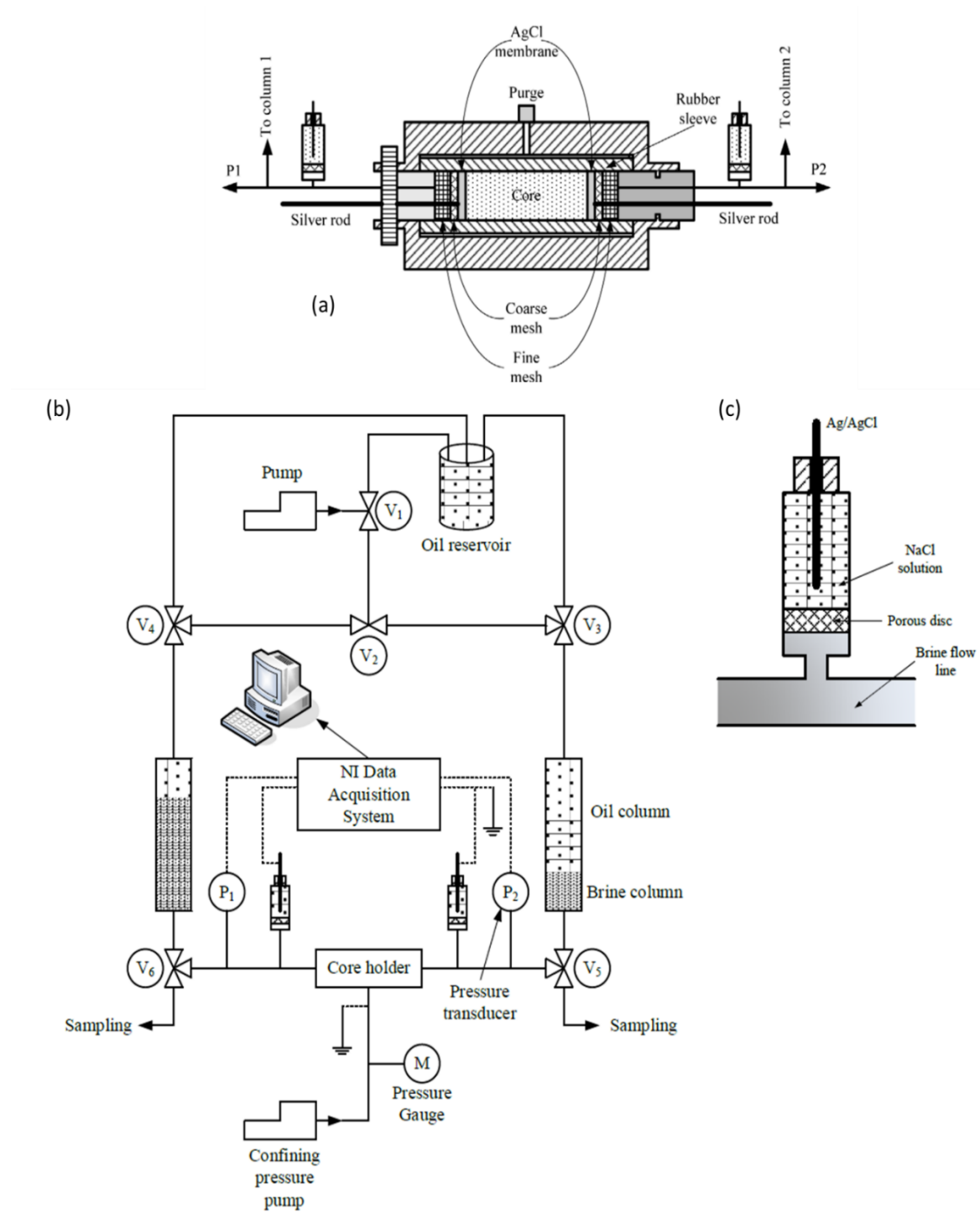


Figure 5.1: The experimental setup for the EK potential coupling coefficient measurements. (a) Cross-section through the core holder. (b) Pressure vessel, electrolyte reservoirs, pump, flow lines (solid lines) and electrical connections (dotted line). (c) Cross-section through the electrodes. Jaafar et al. (2009).

5.3 EK Coupling Coefficients at $S_w = 1$

5.3.1 Results

We begin by showing the results of the EK experiments at $S_w = 1$. Figure 5.2 (a through d) shows the measurements of voltage and pressure difference across each sample when saturated with FMB against time. Brine was flowed through the sample in one direction at different flow rates, until stable voltage and pressure differences were observed for each flow rate. Then, the brine was flowed through the sample in the opposite direction but at the same rates, causing the pressure and voltage to respond in the opposite sense but with the same magnitude. This ensured that electrode polarization effects were small. The flow rates used for each sample are shown in Table 5.2.

Table 5.2: Flow rates used in the EK experiments.

Sample	SS1	SS2	SS3	SS4
Flow rate, ml/min	10, 20 and 30	80, 100, 120, 140, 160 and 180	80, 120, 160, 200 and 240	80, 120, 160, 200 and 240

The linear regression between stabilised pressure and voltage drops for samples SS1 (Figure 5.2e) and SS2 (Figure 5.2f), when saturated with FMB, showed a clear positive gradient, which corresponded to a positive coupling coefficient. To the best of our knowledge, positive values of EK coupling coefficient have not been reported previously for intact sandstones saturated with natural brines. In contrast to samples SS1 and SS2, the EK coupling coefficient measured in samples SS3 and SS4 saturated with FMB was negative (indicated by the negative gradient in Figures 5.2j and h), consistent with published data for sandstones.

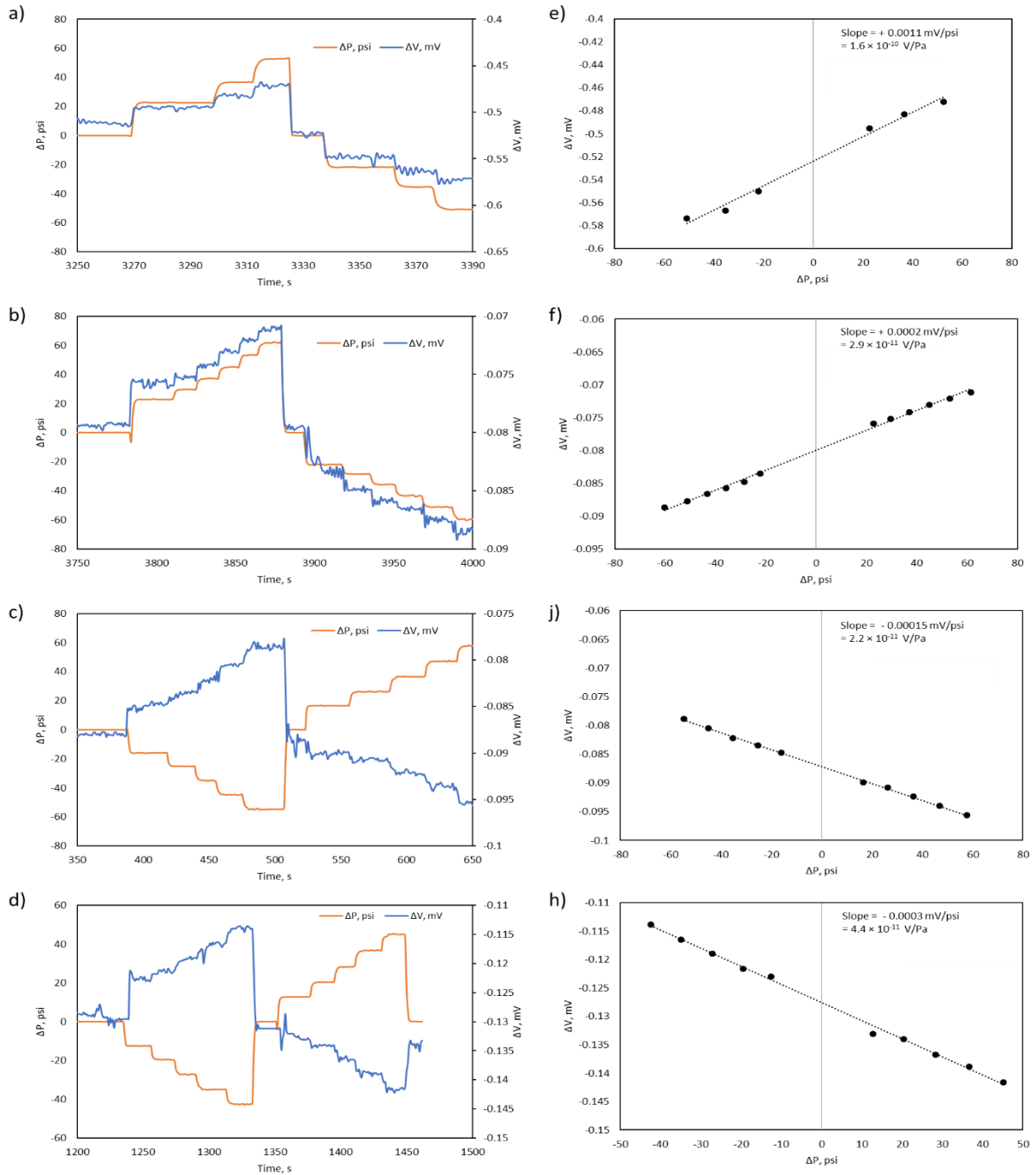


Figure 5.2: a), b), c) and d) Measured pressure drop (ΔP) and voltage drop (ΔV) against time obtained using the streaming potential method for samples SS1, SS2, SS3 and SS4, respectively, when saturated with FMB. e), f), j) and h) Stabilised voltage drop against stabilised pressure drop for samples SS1, SS2, SS3 and SS4, respectively, when saturated with FMB. The slope of a linear regression through the data yield the EK coupling coefficient.

Figure 5.3 shows the measured EK coupling coefficients for the four samples together with published experimental data for a range of silica, sandpacks and natural sandstones saturated with NaCl brine.

Also shown are the coupling coefficient values predicted using equation (3.17). The coupling coefficient measured in samples SS3 and SS4 saturated with FMB was negative and smaller in magnitude compared with published data for NaCl brine (Figure 5.3b). On the other hand, samples SS1 and SS2 saturated with FMB resulted in a positive coupling coefficient, as highlighted in Figure 5.3b. We also show, in Figure 5.3, the EK coupling coefficients for the samples when saturated with SW (0.5 M/L) and DSW (0.01 M/L). The measured coefficients were observed to be more negative and higher in magnitude compared to the measurements with FMB and were consistent with the published data at similar concentrations of NaCl brines.

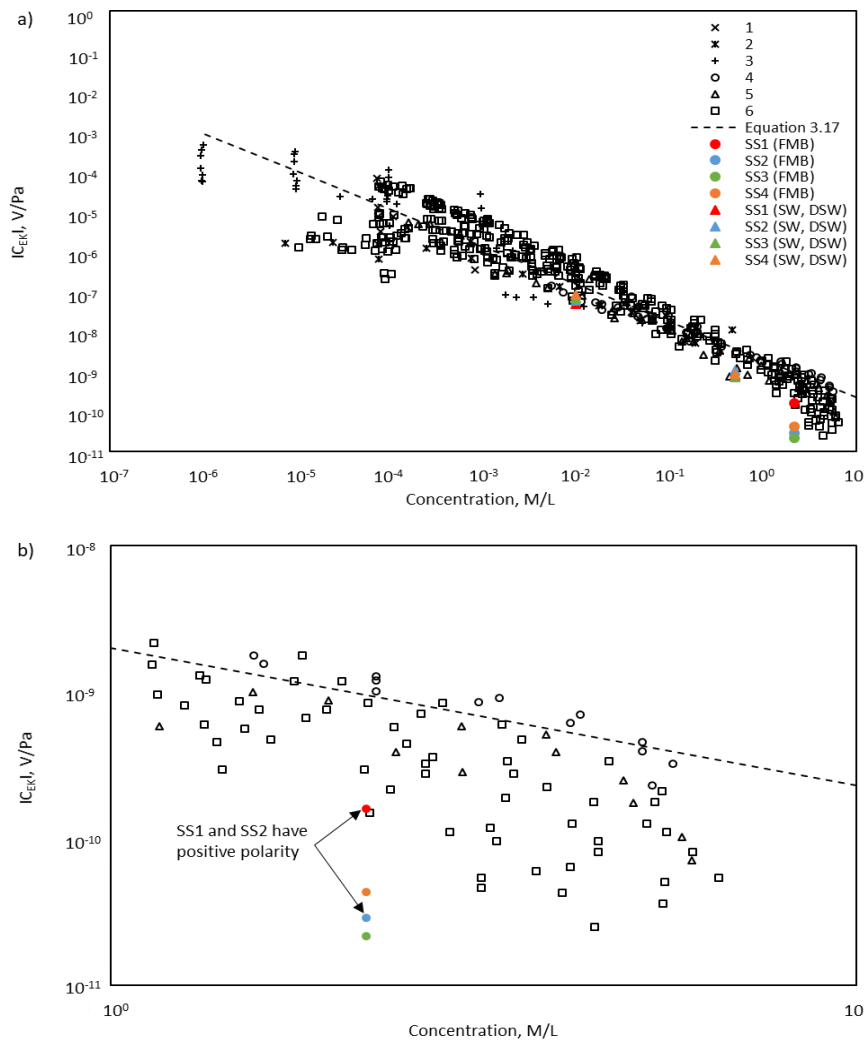


Figure 5.3: Absolute value of the measured EK coupling coefficient as a function of brine concentration expressed as ionic strength, plotted against published data for silica, quartz, sandpacks and intact sandstones obtained with pure NaCl brine. Plot (b) shows the same data as (a) but focussed on the high salinity region of interest. The EK coupling coefficient is negative in polarity for all the

published data and samples SS3 and SS4, while it is positive in samples SS1 and SS2. Data in plot (a) and (b) are from (1) sandstone and NaCl brine (Jiang et al., 1998; Sprunt et al., 1994; Jouniaux and Pozzi, 1995; Jouniaux and Pozzi, 1997; Li et al., 1995; Pengra et al., 1999), (2) sandstone and KCl brine (Alkafeef and Alajmi, 2006), (3) Sand and NaCl brine (Ahmed, 1964; Block and Harris, 2006; Guichet et al., 2003; Ogilvy et al., 1969; Schriever and Bleil, 1957), (4) St. Bees sandstones with NaCl brine (Jaafar et al., 2009), (5) Stainton and Fontainebleau sandstones with NaCl brine (Vinogradov et al., 2010) and (6) Berea, Boise, Fontainebleau, and Lochaline sandstones with NaCl brine (Walker and Glover, 2018). The solid curve represents an empirical model fitted to the data for silica, quartz and glass in pure NaCl brine (Vinogradov et al., 2010).

It is challenging to interpret the positive polarity of the coupling coefficient on the log-log plot shown in Figure 5.3, and therefore, we generated another plot of zeta potential versus brine concentration (Figure 5.4). The zeta potential (ζ) is a function of EK coupling coefficient (C_{EK}) through the modified Helmholtz–Smoluchowski equation as follows (Jouniaux and Pozzi, 1995; Glover, 2015)

$$\zeta = \frac{\mu_w \sigma_r F C_{EK}}{\varepsilon_w} \quad (5.1)$$

where ε_w is the permittivity, μ_w is the brine dynamic viscosity, σ_r is the saturated rock electrical conductivity and F is the formation factor, which is the ratio of the brine electrical conductivity to the saturated rock electrical conductivity. The permittivity (ε_w) and dynamic viscosity (μ_w) were calculated using published correlations (Saunders et al., 2012; Appendix B). The rock conductivity was measured using the internal pair of electrodes connected directly to the core sample (Figure 5.1a), while the brine conductivity was measured using a Metrohm 712 conductivity meter. Rock conductivity measurements will be discussed separately in Section 5.5.

Figures 5.4 (a and b) shows the measured zeta potential for the four samples together with published experimental data for a range of silica, glass beads, sandpacks and natural sandstones saturated with NaCl brine. Figures 5.4 (e and f) shows the same measured data but plotted against published experimental data for silica, sandpacks and natural sandstones saturated with brines containing divalent ions.

The zeta potential measured in samples SS3 and SS4 saturated with FMB was negative and smaller in magnitude compared with published data for NaCl brines (Figure 5.4b). However, when saturated with NaCl brine of the same ionic strength, the two samples returned zeta potential values similar to those

previously observed in NaCl brines (Figure 5.4b). Findings of previous studies revealed that natural sandstones and sandpacks saturated with brines containing divalent ions return negative zeta potential with smaller magnitude compared to pure NaCl: in particular, Datta et al. (2009) (Figure 5.4g) and Vinogradov et al. (2018) (Figure 5.4h) showed that the (negative) zeta potential reduced in magnitude with addition of Ca^{2+} and Mg^{2+} ions to NaCl brine at constant ionic strength.

In contrast to samples SS3 and SS4, the zeta potential measured in samples SS1 and SS2 saturated with FMB was positive. To the best of our knowledge, positive values of zeta potential have not been reported previously for intact sandstones saturated with natural brine. We are confident in the polarity of the interpreted zeta potential: in the experimental setup used here, the zeta potential is positive if the EK potential and pressure respond in the same sense (Figure 5.4d) and vice-versa (Figure 5.4c). Furthermore, the linear regression between ΔP and ΔV exhibits a clear positive gradient (Figures 5.2e and f). All other parameters used to determine the zeta potential in equation (5.1) are positive, so uncertainties in these parameters cannot explain the polarity change.

The zeta potential of samples SS1 and SS2 was then measured again with dilutions of FMB (according to Table 4.6). The positive zeta potential reduced in magnitude with dilution until the polarity inverted to become negative, after which the negative zeta potential increased in magnitude with dilution (Figure 5.4b). When saturated with NaCl brine of the same ionic strength, samples SS1 and SS2 returned negative zeta potential values of similar order but slightly smaller than those observed previously in NaCl brine (Figure 5.4b). It is clear that the samples returned positive zeta potential in formation brine and negative zeta potential in NaCl brine of the same ionic strength.

The effluent brine pH values in all experiments were measured (Figure 5.5a) but were generally consistent within experimental error. The zeta potential became more positive with decreasing pH across all samples, but no such trend was observed for any individual sample (Figure 5.5b). Furthermore, the pH remained larger than 5.75 in all experiments, far higher than the suggested isoelectric point of quartz (e.g. Lorne et al., 1999; Farooq et al., 2011; Jaafar et al., 2013).

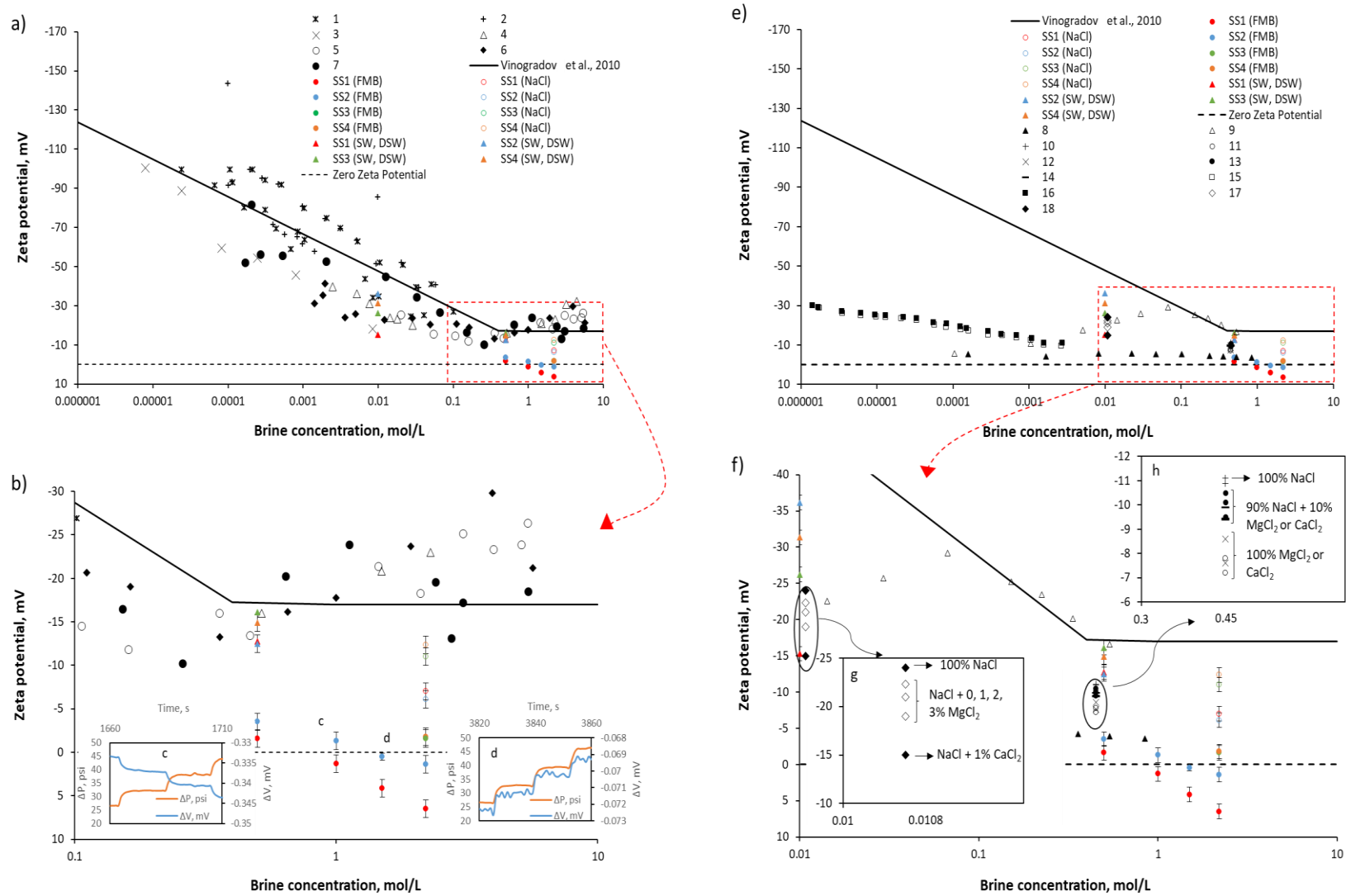


Figure 5.4: Measured zeta potential as a function of brine concentration expressed as ionic strength, plotted against published data for silica, quartz, sandpacks and intact sandstones obtained in (a) and (b) with pure NaCl brine, and (e) and (f) with brines containing divalent ions. Plot (b) shows the same data as (a) but

focussed on the high-salinity region of interest; likewise, plots (f), (g) and (h) show the same data as (e) but focussed on the high-salinity region and two specific datasets of interest. The inset plots (c) and (d) show raw measurements of voltage and pressure against time used to determine the zeta potential. The zeta potential is positive when pressure and voltage respond in the same sense and vice versa. The polarity of the zeta potential is accurately determined even when its value is close to zero. Data in plot (a) and (b) are from (1) silica (Gaudin and Fuerstenau, 1955; Li and de Bruyn, 1966; Kirby and Hasselbrink, 2004), (2) quartz (Pride and Morgan, 1991; Kosmulski et al., 2003), (3) glass beads (Bolève et al., 2007), (4) St. Bees 1 (Jaafar et al., 2009), (5) St. Bees 2 (Jaafar et al., 2009), (6) Stainton and (7) Fountainbleau. Data in plot (e), (f), (g) and (h) are from (8) Berea saturated with CaCl_2 (Li et al., 2018), (9) Berea saturated with NaCl (Li et al., 2018), (10) sandpacks saturated with NaCl (Vinogradov et al., 2018), (11) sandpacks saturated with CaCl_2 (Vinogradov et al., 2018), (12) sandpacks saturated with MgCl_2 (Vinogradov et al., 2018), (13) sandpacks saturated with 90% NaCl + 10% CaCl_2 (Vinogradov et al., 2018), (14) sandpacks saturated with 90% NaCl + 10% MgCl_2 (Vinogradov et al., 2018), (15) crushed Fountainbleau saturated with CaCl_2 (Lorne et al., 1999), (16) crushed Fountainbleau saturated with MgCl_2 (Lorne et al., 1999), (17) silica microchannels saturated with NaCl + 0%, 1%, 2% and 3% MgCl_2 (Datta et al., 2009) and (18) silica microchannels saturated with NaCl + 0% and 1% MgCl_2 (Datta et al., 2009). The inset plots (g) and (h) focus on measurements reported by Datta et al. (2009) and Vinogradov et al. (2018), respectively. Data from this study are presented in coloured dots and circles. The solid curve represents an empirical model fitted to the data for silica, quartz and glass in pure NaCl brine (Vinogradov et al., 2010).

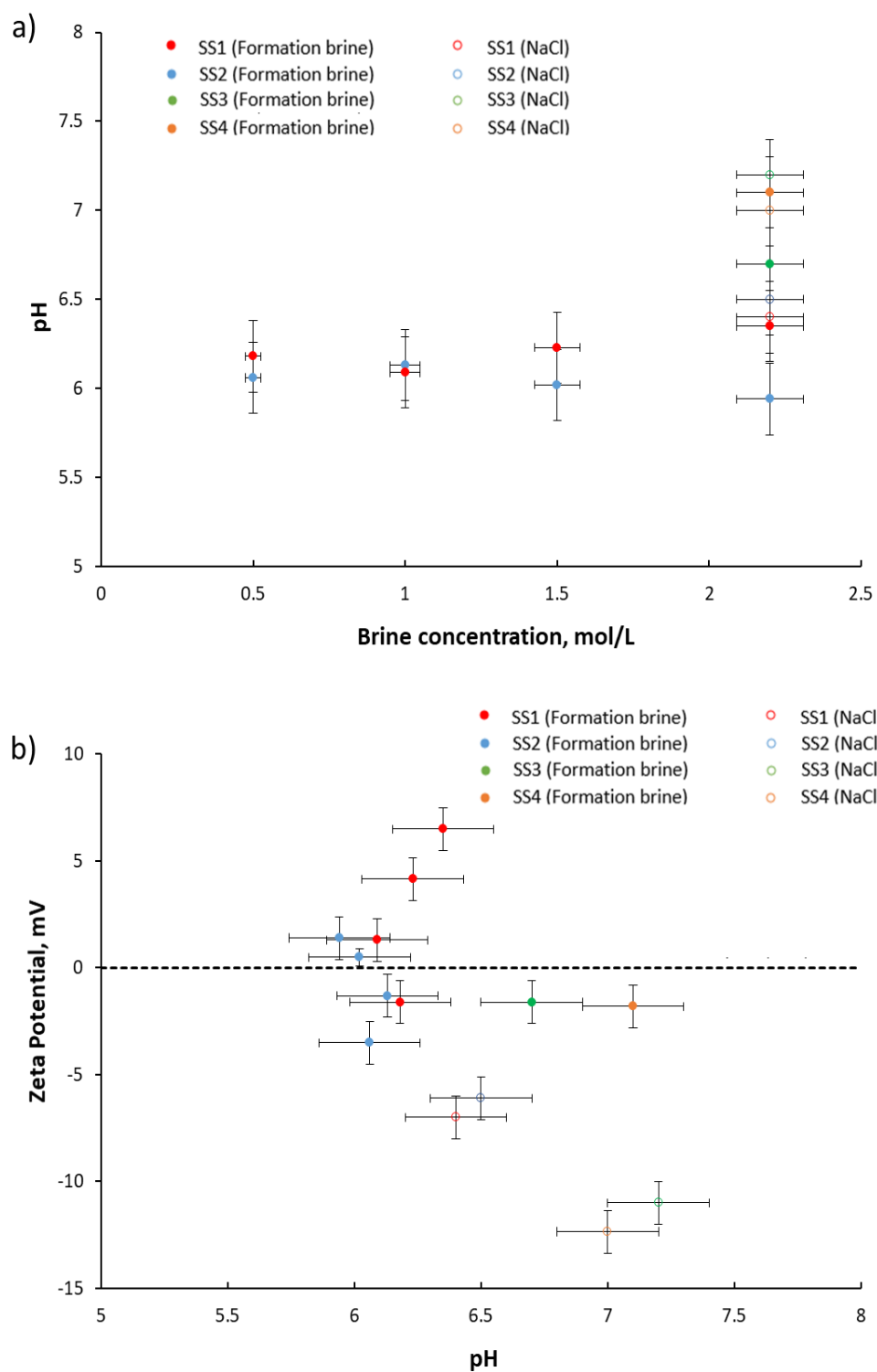


Figure 5.5: a) Measured pH versus brine concentration (ionic strength) for the effluent brines. b) Measured zeta potential versus pH of the effluent brine.

5.3.2 Discussion

Of the four sandstone samples investigated here, the EK coupling coefficients and zeta potentials measured on samples SS3 and SS4 showed consistent behaviour with previous studies: the coupling coefficient and zeta potential were negative and became smaller in magnitude with the addition of divalent ions at constant ionic strength, as shown by comparing the data observed in FMB and equivalent pure NaCl. Samples SS1 and SS2 showed reasonably consistent behaviour when saturated with pure NaCl, but anomalous EK coupling coefficient and positive zeta potential in the high salinity FMB and dilutions of FMB (Figure 5.4).

Samples SS3 and SS4 are primarily composed of a monocrystalline quartz grain framework with detrital feldspar, plagioclase, pyrite and traces of ferroan dolomite and glauconite, as determined from X-ray diffraction measurements and petrographic thin sections (Table 5.3; Figure 5.6). The predominant pore system is primary intergranular pores (Figure 5.6; Al-Jallad et al., 2017). The quartz-dominated mineralogy is similar to the natural sandstones and sandpacks tested in previous EK coupling coefficient and zeta potential measurements (Jaafar et al., 2009; Vinogradov et al., 2010; Thanh and Sprik, 2016; Vinogradov et al., 2018; Walker and Glover, 2018; Li et al., 2018). We suggest that this observation explains the consistency of the EK coupling coefficient and zeta potential values obtained for these samples with the findings of previous studies: the EK coupling coefficient and zeta potential are negative and reduce in magnitude in the natural brine rich in divalent ions compared to the pure NaCl. The reduction in magnitude has been previously explained as reflecting adsorption of Ca^{2+} and Mg^{2+} on the quartz surfaces, and exchange of these ions with clay minerals such as kaolinite and chlorite. Adsorption and ion exchange result in a less negative surface charge (Datta et al., 2009; Vinogradov et al., 2018; Li et al., 2018).

Table 5.3: Properties of the sandstone samples. Porosity and permeability values are specific to each sample, but the mineral proportions are averages across numerous samples of each rock type. Samples SS1 and SS2 have lower quartz content and higher content of clay minerals, calcite, dolomite and siderite than samples SS3 and SS4.

Sample	SS1	SS2	SS3	SS4
Porosity	0.17	0.22	0.25	0.23
Permeability, md	100	500	700	900
Formation Factor	45	22	20	22
Mineralogy	%		%	
Illite/Smectite	0–0.5		0.2–0.8	
Illite + Mica	0.5–6		0.3–3.6	
Kaolinite	0.8–12		0.2–1.1	
Chlorite	0.7–3.8		0.2–1.2	
Quartz	58–85		86–96	
K Feldspar	1.2–1.7		0–3.8	
Plagioclase	0–1.6		0–1.7	
Calcite	0–0.7		0	
Dolomite	0–35		0.5–1	
Siderite	0–15		0	
Halite	0–2		0–1.4	
Pyrite	0–2		0–10.7	

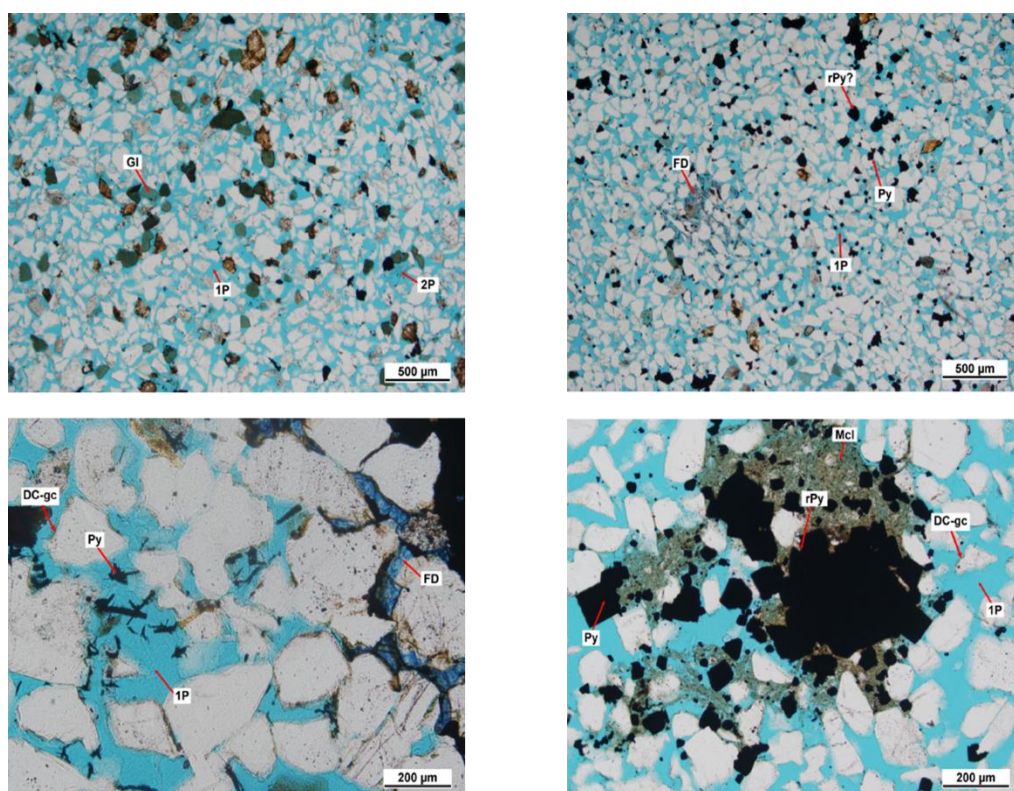


Figure 5.6: Thin-section photomicrographs of the rock type represented by samples SS3 and SS4. 1P: primary porosity, 2P: secondary porosity, Gl: glauconite; FD: ferroan dolomite, Py: pyrite, Mcl: organic-bearing mud clasts; DC-gc: detrital clay grain coat.

Samples SS1 and SS2 are mainly composed of framework grains of a monocrystalline detrital quartz grain framework, authigenic siderite, ferroan dolomite and detrital clay. The predominant pore system is a mix of intergranular pores between quartz grains and micropores between clay particles and authigenic siderite (Table 5.3; Figure 5.7; Al-Jallad et al., 2017). We suggest that the anomalous positive EK coupling coefficient and zeta potential in these samples partially reflect divalent cation adsorption and ion exchange as suggested in previous studies, but also the critical role of dolomite and siderite. These minerals have been previously reported to exhibit positive zeta potential, especially in brines rich in divalent cations, such as the formation brine tested here (Mahani et al., 2017; Al-Mahrouqi et al., 2017; Li et al., 2021).

The streaming potential method provides an average EK coupling coefficient and zeta potential over the entire sample; thus, if a sufficient portion of the pore area comprises dolomite or siderite, then the measured coupling coefficient and zeta potential of the core sample will include a contribution from these minerals, in addition to the effects of ion adsorption and exchange, thus switching the sample to a small but positive polarity. Additionally, dissolution of dolomite and siderite may release Mg^{+2} , Ca^{2+} and Fe^{+2} cations, which could further adsorb onto other mineral surfaces (Li et al., 2018; Feng et al., 2018; Li et al., 2021). Effluent brine analysis showed no measurable change in ionic composition, although the high concentration of the brine made it difficult to observe any small changes. The coupling coefficient and zeta potential of these samples were negative in NaCl brine and in dilute FMB, which may suggest that all three effects of positive dolomite and/or siderite zeta potential, divalent ion adsorption and ion exchange are required for the sample to return positive coupling coefficient and zeta potential.

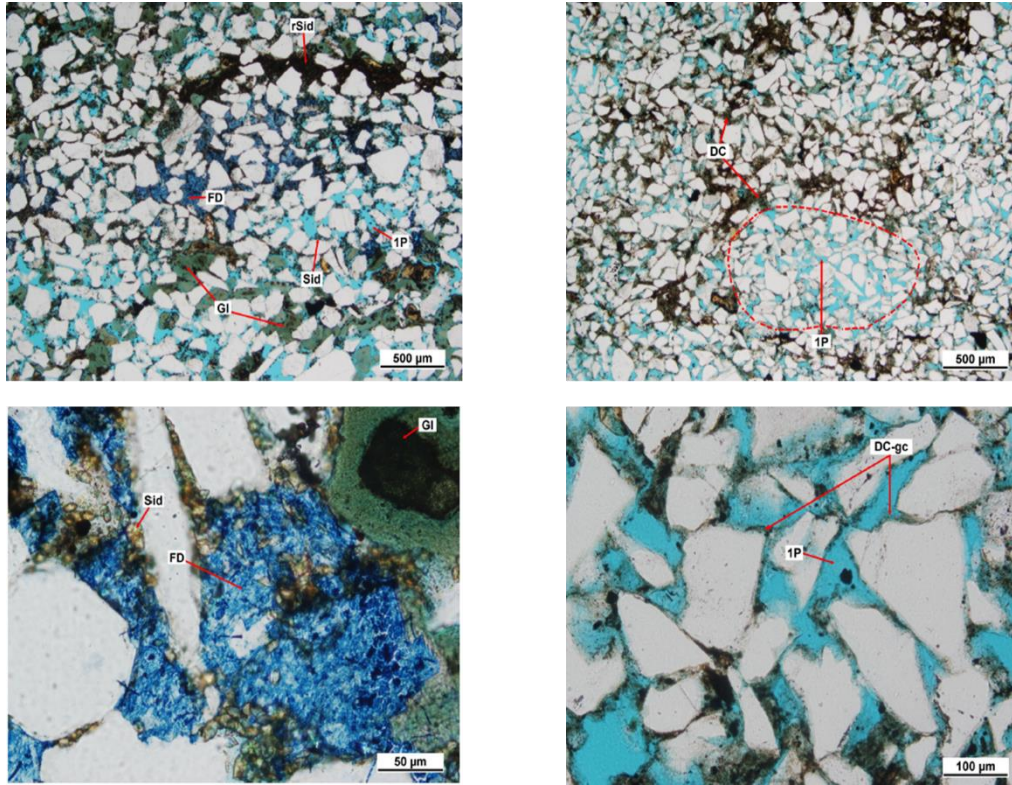


Figure 5.7: Thin-section photomicrographs of the rock type represented by samples SS1 and SS2. 1P: primary porosity, Sid: siderite, Gl: glauconite, FD: ferroan dolomite, DC: detrital clay, DC-gc: detrital clay grain coat.

5.4 EK Coupling Coefficients at $S_w = 1 - S_{or}$

5.4.1 Results

Table 5.4 presents a summary of the results of the core flooding process for the four samples. Figure 5.8 shows comparisons between the EK coupling coefficients and zeta potentials measured using the three investigated brines (FMB, SW and DSW) at $S_w = 1$ and $S_w = 1 - S_{or}$ for the four sandstone samples.

The results at $S_w = 1 - S_{or}$ are obviously different compared to the results at $S_w = 1$. Three samples (SS2, SS3 and SS4) resulted in a positive EK coupling coefficient and zeta potential at $S_w = 1 - S_{or}$ when measured with FMB. The zeta potential and EK coupling coefficient of sample SS2, when measured with FMB, were positive at $S_w = 1$ and became more positive at $S_w = 1 - S_{or}$. The zeta potential and EK coupling coefficient of samples SS3 and SS4, when measured with FMB, inverted from being negative at $S_w = 1$ to positive at $S_w = 1 - S_{or}$. In contrast to that, sample SS1 resulted in negative zeta potential

and EK coupling coefficient at $S_w = 1 - S_{or}$ compared positive values at $S_w = 1$. When measured with SW and DSW, the zeta potentials and EK coupling coefficients at $S_w = 1 - S_{or}$ were negative for all the samples, however, less negative (more positive) compared to the results at $S_w = 1$.

There is an insufficiency in the published experimental data for coupling coefficient and zeta potential at $S_w = 1 - S_{or}$, which were obtained at different conditions and rock samples; therefore, it is not convenient to plot them with the results of this study. Vinogradov and Jackson (2011) measured the coupling coefficients on sandstone samples saturated with NaCl brine and paraffin and found that the results at $S_w = 1 - S_{or}$ are slightly higher than $S_w = 1$. They ran their core floods directly after drainage without aging the samples. Jackson and Vinogradov (2012) measured the coupling coefficients and zeta potential on carbonate samples at $S_w = 1 - S_{or}$ with and without aging the samples and compared with the values at $S_w = 1$. They noted that the un-aged sample results were comparable with the results at $S_w = 1$, consistent with the findings of Vinogradov and Jackson (2011). On the other hand, they found that the results for the aged samples are clearly different compared to $S_w = 1$. Jackson et al. (2016) and Collini et al. (2020) also reported zeta potential measurements at $S_w = 1 - S_{or}$ (after aging) and $S_w = 1$ for carbonate samples and different oils and observed the results are different. They found that some samples resulted in a more positive zeta potential at $S_w = 1 - S_{or}$ compared to $S_w = 1$, while the others resulted in a more negative values. They interpreted this change in zeta potential, whether more positive or more negative, as an indicator of the polarity of the zeta potential at the oil-brine interface. Therefore, they suggested that if the change in zeta potential ($\Delta\zeta = \zeta|_{S_w=1-S_{or}} - \zeta|_{S_w=1}$) is positive, then the oil-brine zeta potential is positive and vice versa. The polarity of the oil-brine interface can vary according to the experimental conditions; however, there is no clear correlation between the oil, brine, and rock properties and the polarity of the oil-brine interface (Collini et al., 2020).

Table 5.4: Summary of the drainage and core flooding processes on the sandstone core samples.

Sample	Drainage	Primary core flood (FMB)		Secondary core flood (SW)		Tertiary core flood (DSW)	
	S_{wi}	Recovery, %	$S_{or FMB}$	Additional recovery, %	$S_{or SW}$	Additional recovery, %	$S_{or SW}$
SS1	0.14	71.429	0.246	2.857	0.221	0.714	0.215
SS2	0.1	65.600	0.310	0.800	0.302	0.400	0.299
SS3	0.125	57.778	0.369	0.370	0.366	0.370	0.363
SS4	0.08	64.00	0.331	1.600	0.316	0.400	0.313

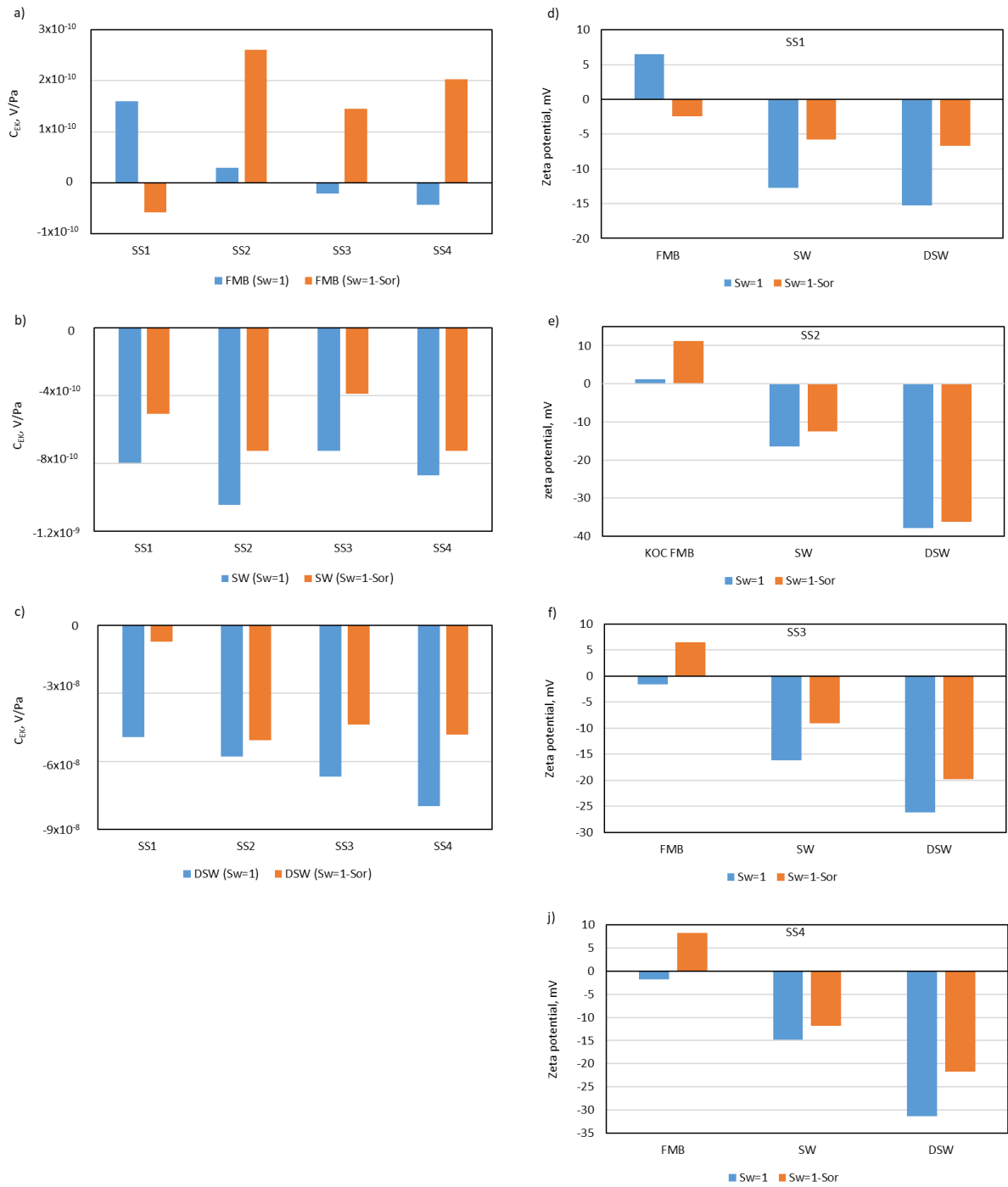


Figure 5.8: Comparison between the EK coupling coefficient and zeta potential measured at $S_w = 1$ and $S_w = 1 - S_{or}$ for the four sandstone samples used in this study. Plots a), b) and c) show the EK coupling coefficients measured with FMB, SW and DSW, respectively. Plots d), e), f) and j) show the zeta potential measurements for samples SS1, SS2, SS3 and SS4, respectively.

5.4.2 Discussion

Of the four sandstone samples investigated here, the EK coupling coefficients and zeta potentials measured on samples SS2, SS3 and SS4 with FMB at $S_w = 1 - S_{or}$ showed more positive values than $S_w = 1$ (Figure 5.8). This positive change in zeta potential and coupling coefficient is consistent with a positive zeta potential at the oil-brine interface, as suggested by Jackson et al. (2016) and Collini et al. (2020). In contrast to that, sample SS1 resulted in more negative EK coupling coefficient and zeta potential when measured with FMB at $S_w = 1 - S_{or}$ compared to $S_w = 1$ (Figure 5.8). According to the theory presented by Jackson et al. (2016) and Collini et al. (2020), this is consistent with a negative zeta potential at the oil-brine interface. Although the same oil and brine and the same experimental conditions were used for conducting the measurements for the four samples, the interpreted polarity of the oil-brine interface was found to be dependent on the rock sample, being positive in three samples and negative in the fourth one. Collini et al. (2020) reported the same phenomenon for one of the oil samples they used where they reported more positive and more negative zeta potential for two different rock samples using the same oil and brine. They also reported a dependency of the polarity of the oil-brine zeta potential on the temperature.

When measured with SW and DSW, the four samples showed consistent behaviour of negative EK coupling coefficients and zeta potentials at $S_w = 1$ with less negative (more positive) values at $S_w = 1 - S_{or}$. This behaviour can be interpreted to be due to either a positive or a less negative zeta potential at the oil-brine interface. The results for samples SS2, SS3 and SS4 can be explained as a result of a positive oil-brine zeta potential at the oil brine interface, consistent with the positive oil-brine zeta potential observed with FMB (Figure 5.8). On the other hand, the results for sample SS1 with SW and DSW cannot be explained by a positive oil-brine zeta potential as for SS2, SS3 and SS4, because of a hypothesised negative zeta potential at the oil-brine interface (consistent with the negative oil-brine zeta potential observed with FMB). However, we acknowledge ambiguity of a certain extent while recording the interpreted zeta potential when measured using SW and DSW.

Assuming that the change in zeta potential between $S_w = 1$ and $S_w = 1 - S_{or}$ is indicative of the zeta potential at the oil-brine interface, our results, in addition to the case reported by Collini et al. (2020),

suggest that the zeta potential at the oil-brine interface depends on the crude oil properties, brine composition and rock type.

The measurements of the EK coupling coefficient at $S_w = 1 - S_{or}$ is extremely crucial for our feasibility study as these values will be used for SP modelling in the SP solver instead of the implemented correlation (equation 3.17), which was used to best match the experimental data from the literature for fully saturated sandstones with NaCl. Figure 5.9 shows the measured coupling coefficients for the four samples at $S_w = 1 - S_{or}$ with the three investigated brines. Clearly, our data points deviate from the line predicted by equation 3.17, either being lower in magnitude or having opposite polarity. This confirms the importance of conducting these measurements for the feasibility assessment and the modelling work.

In this study, we conducted the EK experiments at ambient conditions using dead oil and there was no attempt to run the experiments at reservoir conditions or/and using live oil. Vinogradov and Jackson (2015) and Vinogradov et al. (2018) observed that the EK coupling coefficient slightly decreases with increasing temperature. There is no published data on the effect of live oil on the EK experiments; however, the behaviour is expected to be different due to the different oil composition and hence, the interaction between the oil, water and mineral surfaces.

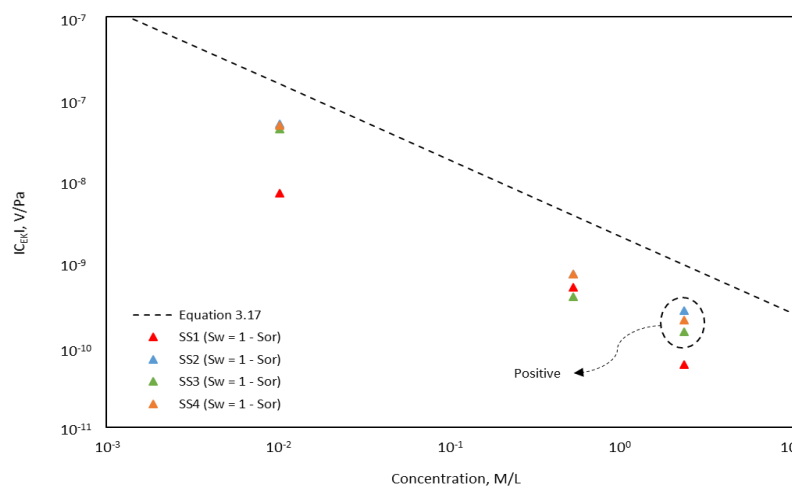


Figure 5.9: Absolute value of measured EK coupling coefficient at $S_w = 1 - S_{or}$ as a function of brine concentration expressed as ionic strength, plotted against the dashed line representing equation 3.17.

The polarity of the highlighted three points for samples SS2, SS3 and SS4 is positive while the remaining data points and the line predicted by equation 3.17 have a negative polarity.

5.5 Electrical Conductivity of Rock Samples

The electrical conductivity of partially saturated rocks is vital for SP modelling, as it is one of the main inputs to the SP solver, and the approach described in Chapter 3 uses Archie's equation (equation 3.15) to calculate it. It is also very important for the calculation of the zeta potential discussed in previous sections (equation 5.1). The rock conductivity was measured for each sample at $S_w = 1$, $S_w = 1 - S_{or}$ and $S_w = S_{wirr}$. The conductivity was measured using the two internal electrodes shown in Figure 5.1a over the frequency range 10 Hz to 2 MHz. The measured parameters were frequency (f), impedance (Z, ohm), and resistance (R, ohm), as shown in Figure 5.10 (a, c and e). The reactance (X, ohm) was then calculated using

$$X = \sqrt{Z^2 - R^2} \quad (5.2)$$

The conductivity of the saturated sample (ρ_r , S/m) was then calculated using

$$\rho_r = \frac{L}{R\pi r^2} \quad (5.3)$$

where L and r are the length and the radius of the core, respectively, and R is the value of measured resistance that corresponds to the minimum reactance (e.g. Figures 5.10b, d, and f).

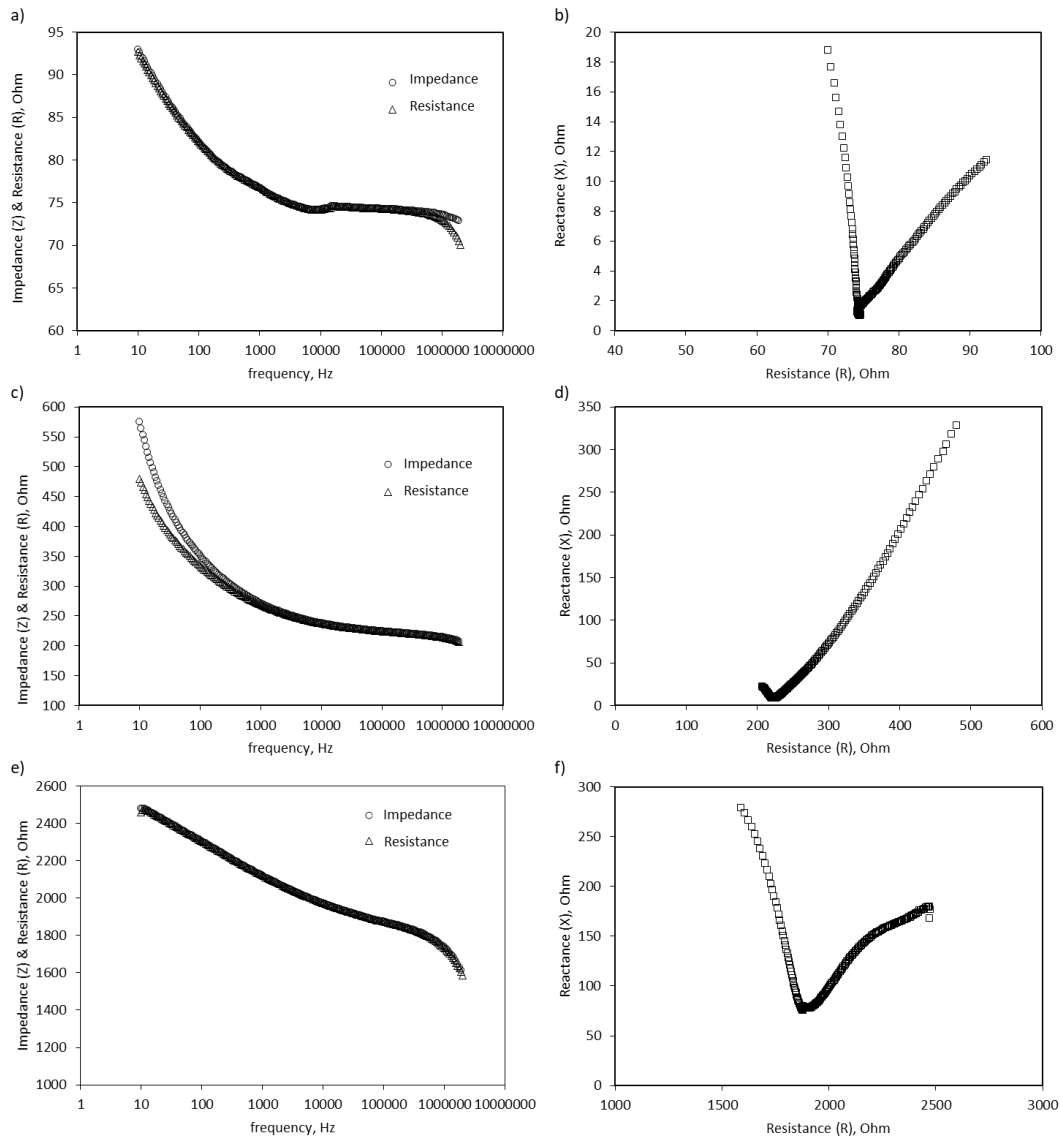


Figure 5.10: Example of conductivity measurements for sample SS4. (a) Impedance and resistance versus frequency for sample SS4 when fully saturated with FMB. (b) Reactance versus resistance based on the data on (a). (c) Impedance and resistance versus frequency for sample SS4 at residual oil saturation (minimum oil + maximum formation brine). (d) Reactance versus resistance based on the data on (b). (e) Impedance and resistance versus frequency for sample SS4 at irreducible water saturation (maximum oil + minimum formation brine). (f) Reactance versus resistance based on the data on (e).

5.5.1 Results and discussion

The rock conductivity measurements for the four sandstone samples are summarized in Figure 5.11. Figure 5.11 (a, d, g and j) shows the measured conductivity when the samples were fully saturated with the three investigated brines. These values were used to obtain the zeta potential through equation (5.1);

however, they will not be used in the SP solver as the sandstones in BGSU do not exist at fully saturated conditions.

The measurements of the rock conductivity at $S_w = 1 - S_{or}$ are shown in Figure 5.11 (b, e, h and k) for the investigated brines against the conductivity predicted using Archie's equation (equation 3.15). It is obvious that the conductivity predictions using Archie's equation are overestimated. Therefore, we tried matching the experimental data by adjusting the cementation and saturation exponents (dashed line), and this updated model will be implemented in the SP solver in Chapter 7 for the rock types represented by these samples.

Finally, we reported the conductivity measurements at $S_w = S_{wirr}$ in Figure 5.11 (c, f, i and l). These measurements were reported only for the FMB. The results were compared against the predictions of Archie's equation (equation 3.15) and the updated model developed to match the data at $S_w = 1 - S_{or}$. It is difficult to evaluate the performance of the models (Archie's and updated Archie's) on the basis of a single point per sample; therefore, it was assumed that the updated model will continue to work for low water-saturation ranges.

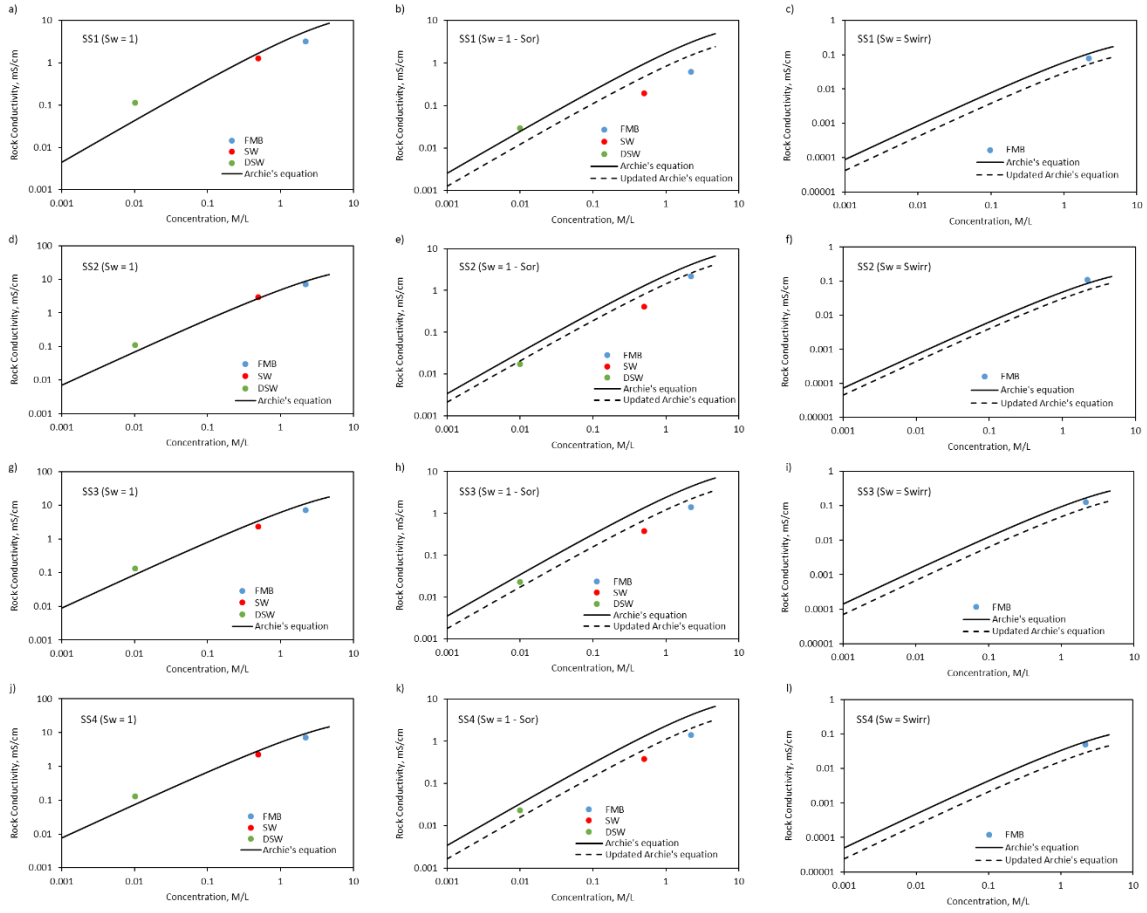


Figure 5.11: Rock conductivity versus brine concentration for sample SS1 at a) $S_w = 1$, b) $S_w = 1 - S_{or}$ and c) $S_w = S_{wirr}$ measured with the three brines investigated in this study. Rock conductivity versus brine concentration for sample SS2 at d) $S_w = 1$, e) $S_w = 1 - S_{or}$ and f) $S_w = S_{wirr}$ measured with the three brines investigated in this study. Rock conductivity versus brine concentration for sample SS3 at g) $S_w = 1$, h) $S_w = 1 - S_{or}$ and i) $S_w = S_{wirr}$ measured with the three brines investigated in this study. Rock conductivity versus brine concentration for sample SS4 at j) $S_w = 1$, k) $S_w = 1 - S_{or}$ and l) $S_w = S_{wirr}$ measured with the three brines investigated in this study. The solid line represents Archie's equation (equation 3.15) with $m = 1.8$ and $n = 2$, while the dashed line represents an updated version of Archie's equation by updating m and n to best match the experimental data.

5.6 Conclusions

The EK coupling coefficient and zeta potential were measured on four BGSU core plugs when fully saturated and at residual oil saturation using FMB, SW, DSW and NaCl brines. In fully saturated measurements, two samples returned a small but negative values when measured with FMB, consistent with previous studies of quartz-dominated sandstones in which it has been suggested that adsorption of divalent ions onto quartz mineral surfaces and ion exchange with clay minerals, yield a less negative zeta potential. The other two samples returned a positive coupling coefficient and zeta potential when measured with FMB, which have not been previously observed and is interpreted to be caused by the presence of dolomite and siderite mineral surfaces, which are positively charged in the presence of high concentrations of divalent ions, in addition to the adsorption of divalent ions onto quartz mineral surfaces and ion exchange with clay minerals.

At residual oil saturation, the measured parameters behaved in a different manner compared to fully saturated conditions. Three of the four samples resulted in a positive change in the measured parameters when measured with FMB. This positive change indicates a positively charged oil-brine interface. On the other hand, the fourth sample resulted in negative change in the measured zeta potential and coupling coefficient when measured with FMB. This negative change indicates a negatively charged oil-brine interface. With the same oil, brine and experimental conditions, this change in oil polarity among the samples is suggested to be dependent on the rock itself and the interaction between rock, brine and oil.

The findings of this experiment revealed that it can be erroneous to assume that sandstones are negatively charged when fully saturated, or that experimentally determined EK coupling coefficients and zeta potential trends obtained in quartz-dominated samples saturated with simple NaCl brines are applicable in the subsurface. Only a few studies have tested rocks and brines of complex nature such as those investigated in this study, and thus, the prevalence of positively charged brine-mineral interface in saturated sandstones in nature remains unknown and obscure. We also showed that it is inaccurate to assume that the EK coupling coefficient and zeta potential at residual oil saturation can be approximated by the values measured for fully saturated rocks. Very few studies have investigated the behaviour at residual oil saturated, and thus, it continues to remain uncertain.

Finally, we reported the rock conductivity measurements for the fully and partially saturated samples. We found that the Archie's equation overestimates the conductivity. Therefore, a new model was fitted to the measured data by adjusting the cementation and saturation exponents of Archie's equation.

The measured parameters reported in this chapter (EK coupling coefficient and rock conductivity), confirmed the importance of the experimental work for the SP feasibility assessment, represented in obtaining realistic values that are not consistent with the assumptions considered in Chapter 3. The parameters reported here will be used in Chapter 7 to update the SP solver predictions.

Chapter 6

Exclusion-Diffusion (ED) potential experiment

6.1 Introduction

The main objective of the ED experiment was to characterise the ED potential in BGSU core plugs when fully or partially saturated with the FMB in order to obtain the ED coupling coefficients, which is one of the main inputs to the SP solver developed in chapter 3. In Chapter 3, the ED coupling coefficient was defined to vary between that of a pure diffusion case and pure exclusion case as a function of a dimensionless number termed the exclusion efficiency (ε), which varies between zero (diffusion dominated) and 1 (exclusion dominated) according to equation (3.26). The exclusion efficiency in fully saturated rocks varies with the rock pore-size (Leinov and Jackson, 2014), so an appropriate value of exclusion efficiency value must be assigned in the SP solver to each rock type; for example, MacAllister et al. (2019) measured values of $\varepsilon=0-0.1$ and $\varepsilon=0.3-0.4$ for carbonates and shales, respectively. This applies to Rock type 1 and 2 (the shaly non reservoir layers), where the rocks are fully saturated or at very high water saturations. Therefore, the first aim of this chapter is to investigate the ED potential and determine representative values of exclusion efficiency for the rock samples of rock type 1 and 2 (samples SH1, SH2, SH3, SH4 and SH5 shown in Table 4.8).

In reservoirs partially saturated with water, the exclusion efficiency also varies with water saturation (Ortiz et al., 1973). In the SP solver described in chapter 3, we used the approach described by Ortiz et al. (1973), who was the only one to investigate the ED potential at partial saturations, to model the behavior of the exclusion efficiency at the saturation endpoints (irreducible water saturation [$S_w = S_{wirr}$] and residual oil saturation [$S_w = 1 - S_{or}$]). Based on Ortiz et al. (1973), we assumed that the ED potential is diffusion dominated at $S_w = 1 - S_{or}$ ($\varepsilon = 0$) and exclusion dominated at $S_w = S_{wirr}$ ($\varepsilon = 1$). At intermediate saturations, we model the saturation-dependence of the exclusion efficiency using the model developed by Jackson et al. (2012b) according to equation (3.27). This approach applies to the permeable rock types (RT 3, 4, 5 and 6) where the rocks are partially saturated.

So, the second aim of this chapter is to investigate the ED potential, determine representative values of exclusion efficiency for the permeable rock samples (samples SS1, SS2, SS3 and SS4 shown in Table 4.8) at the saturation end points and to compare the results against the approach considered in Chapter 3.

Beside the ED potential and exclusion efficiency, we measured the rock conductivity for the fully saturated rock samples (rock type 1 and 2) as a continuation to the work done in Section 5.5. Shale rock conductivity is one of the key factors controlling the SP as it controls the spread of the SP beyond the permeable layers, and the approach considered in Chapter 3 uses Archie's equation (equation 3.15) to calculate it. Thus, experimentally measured rock conductivity are also of great value for SP modelling.

6.2 Material and Methods

6.2.1 Core plug preparation

The Four sandstone and five shale samples shown in Table 4.8 were cleaned as described in Section 4.8.2. The basic rock properties are summarized in Table 6.1. After cleaning, the samples were dried and subsequently vacuum saturated with the FMB, prepared using de-ionised water (resistivity of 16 M Ω) and reagent grade salts. The compositions of the FMB is shown in Table 4.6, and it has a total ionic strength of 2.2 M/L. The samples were saturated with the FMB to mimic the subsurface conditions of the reservoir from which the plugs were collected. At this stage, the samples were ready for use in ED potential measurements at full saturation ($S_w = 1$) using the experimental approach described in the next section.

For the ED potential measurements at partial saturation ($S_w = 1 - S_{or}$ and $S_w = S_{wirr}$), we only used the sandstone samples. In most subsurface environments, shales are fully water saturated because the small pore size and large capillary entry pressure prevent invasion of non-wetting crude oil or other fluids. In contrast, sandstones exhibit a range of water saturations values. After measuring the ED potential at saturation, the sandstone samples were cleaned and re-saturated with the FMB as described previously. The samples were then flooded with a natural crude oil (specific gravity = 0.92) at low rate (0.01

mL/min) until no water was produced and we had established the irreducible water saturation ($S_w = S_{wirr}$). The drained samples were submerged in containers filled with the same crude oil and aged for three weeks at 80°C to restore the natural wetting state, following the approach of Jackson et al. (2016). After aging, the ED potential measurements were performed again with the same experimental approach described in the next section.

The samples were then flooded with the FMB until no oil flowed out of the core sample and we had established the residual oil saturation ($S_w = 1 - S_{or}$). The ED potential was measured again using the same experimental approach.

Table 6.1: Rock properties for samples used in this study.

Sample no.	SS1	SS2	SS3	SS4	SH1	SH2	SH3	SH4	SH5
Porosity	0.17	0.22	0.25	0.23	0.32	0.26	0.28	0.3	0.31
Permeability, md	100	500	700	900	1.2	1	0.8	1.5	1.1
Dimension	5.5	5.5 x	5.5 x	5.5 x	5.8 x	5.2 x	5.4 x	5.9 x	5.7 x
Length (cm) x	x	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8
Diameter (cm)	3.7								

6.2.2 Experimental procedures

The same experimental approach was used to measure the ED potential for all samples and all saturation conditions investigated. The approach was described by Leinov and Jackson (2014) and MacAllister et al. (2019) and comprises two stages: a column experiment and a plug experiment. The two-stage approach was designed to account for concentration-dependent electrode potentials (Jougnot and Linde, 2013, Leinov and Jackson, 2014).

In the column experiment, two reservoirs arranged in a vertical column, each containing one of the brines of interest (FMB and SW in this case; Table 4.6) were connected via a valve (Figure 6.1b). One measurement electrode was installed in each reservoir. The lower reservoir was filled with the higher concentration brine to a level above the valve (V_2 in Figure 6.1b) to ensure no air was trapped. The valve was closed and any excess brine was removed. The upper reservoir was then filled with the lower concentration brine. Orienting the reservoirs in this way ensured the denser fluid was at the base of the

column to minimize convective mixing. The experiment was initiated by opening the valve (V_2), and the electrical potential across the gravity-stabilized salinity front was measured. The measured electrical potential is termed the apparent column electric potential (ΔV_{AC}). This apparent column potential is made up of the diffusion potential across the concentration front (ΔV_D) and a concentration-dependent electrode potential (ΔV_C) (Leinov and Jackson, 2014)

$$\Delta V_{AC} = \Delta V_D + \Delta V_C \quad (6.1)$$

The diffusion potential (ΔV_D) for the multi-ionic brines of interest was calculated as follows (Lanteri et al., 2009)

$$\Delta V_D = -\frac{k_B T}{e} \left(\frac{\sum_i K_i D_i z_i (C_i^L - C_i^0)}{\sum_i K_i D_i z_i^2 (C_i^L - C_i^0)} \right) \ln \left(\frac{\sum_i K_i D_i z_i^2 C_i^0}{\sum_i K_i D_i z_i^2 C_i^L} \right) \quad (6.2)$$

where subscript i refers to a specific ionic species, K_i is the hindrance diffusion coefficient, D_i is the diffusion coefficient, c_i is the concentration (subscripts 0 and L refers to the highest and lowest concentrations, respectively), z_i is the charge number, k_B is the Boltzmann constant, e is the electron charge and T is the absolute temperature (Lanteri et al., 2009). The derivation of equation (6.2) together with the parameters used for the investigated brines are shown in Appendix C. Substituting the diffusion potential ΔV_D calculated from equation (6.2) into equation (6.1) yields the electrode potential (ΔV_C).

The error in the electrode potential ϵ_C was calculated as follows (Hughes and Hase, 2010)

$$\epsilon_C = \sqrt{\epsilon_D^2 + \epsilon_{AC}^2} \quad (6.3)$$

Where ϵ_D and ϵ_{AC} are the errors in the diffusion potential and the apparent column potential, respectively. The error in the diffusion potential was calculated assuming that the composition is uncertain by $\pm 10\%$ and calculating a corresponding maximum and minimum diffusion potential. The error in the apparent column potential ϵ_{AC} was determined from the reproducibility of repeat measurements.

In the plug experiment, the sample of interest was placed in a rubber sleeve that fits tightly around the plug, and connected to two reservoirs, each containing one of the brines of interest (FMB and SW; Figure 6.1a). The brine level in each reservoir was identical, eliminating pressure gradients across the

plug, to eliminate electrokinetic potential. Both reservoirs and the sleeve were electrically isolated, and no metallic components other than the Ag/AgCl electrodes were in contact with the brines or the sample, to avoid sources of redox potential. One of the measurement electrodes used in the column experiment was installed on each side of the sample in contact with the same brine. The measurement was started by opening the valve V_1 (Figure 6.1a) to expose the end of the sample to the brine of different concentration, and the electrical potential across the core plug was measured. All measurements during the column and plug experiments were taken with reference to the electrode in the low salinity reservoir. The measured electrical potential in this experiment is termed the apparent plug potential (ΔV_{AP}). The apparent plug potential is made up of the ED potential across the sample (ΔV_{ED}) and the known electrode potential (ΔV_C)

$$\Delta V_{AP} = \Delta V_{ED} + \Delta V_C \quad (6.4)$$

The ED potential was then calculated from the measured plug potential and the known electrode potential. The error in the ED potential ϵ_{ED} was calculated as follows (Hughes and Hase, 2010)

$$\epsilon_{ED} = \sqrt{\epsilon_D^2 + \epsilon_{AC}^2 + \epsilon_{AP}^2} \quad (6.5)$$

where ϵ_{AP} is the error in the apparent plug potential, calculated using the same approach used for ϵ_{AC} . The electrical potential in both experiments was measured using bespoke Ag/AgCl electrodes and a National Instruments NI9219 voltmeter (internal impedance $> 1 \text{ G}\Omega$, accuracy 0.18%, resolution 50 nV; Figure 2). The electrodes were connected to the voltmeter using copper coaxial cables. All measurements were performed at ambient laboratory temperature (23 °C). This ensured the elimination of the contribution of the thermoelectrical potential to the measured SP.

The ED potential was used to estimate the exclusion efficiency of the samples as follows (Westermann-Clark and Christoforou 1986)

$$\varepsilon = \frac{\Delta V_{ED} - \Delta V_D}{\Delta V_D - \Delta V_E} \quad (6.6)$$

where ΔV_D and ΔV_E are the pure diffusion and pure exclusion potential, respectively. The pure exclusion potential can be calculated using equation (6.2) applied to the counter-ions only.

Bespoke Ag/AgCl electrodes similar to those used by MacAllister et al. (2019) were used to measure the electrical potential. Each electrodes was located within a NaCl brine bath housed by the electrode casing, connected to the reservoir by an electrically conductive but low permeability ceramic disk (Figure 6.1c). The ceramic disk inhibited convective mixing and diffusion of ion species into the electrode casing to maintain the chloride content throughout the experiments (Snyder et al., 1999). The electrode casing was filled with NaCl brine the same ionic strength as the high salinity brine. This setup results in a higher chloride content in the electrode casing compared to the main reservoir, which buffers the effect of ion concentration gradients across the ceramic disk and maintains a stable chloride content around the electrode (Tallgren et al., 2005). The presence of chloride ions in the electrode casing slows the degradation of the Ag/AgCl coating on the electrodes and reduces the generation of time-dependent results (Raynauld and Laviolette, 1987; Jougnot and Linde, 2013). Ions other than chloride and sodium gradually diffuse from the reservoir into the electrode casing, changing the composition and causing degradation of the electrodes (MacAllister et al., 2019). Designing the electrode in this way minimized these effects and ensured the stability of the electrode coating for the first few hours of the experiments. Once the electrical voltage signal started to drift beyond a few mV, the experiments were terminated as this indicated electrode degradation.

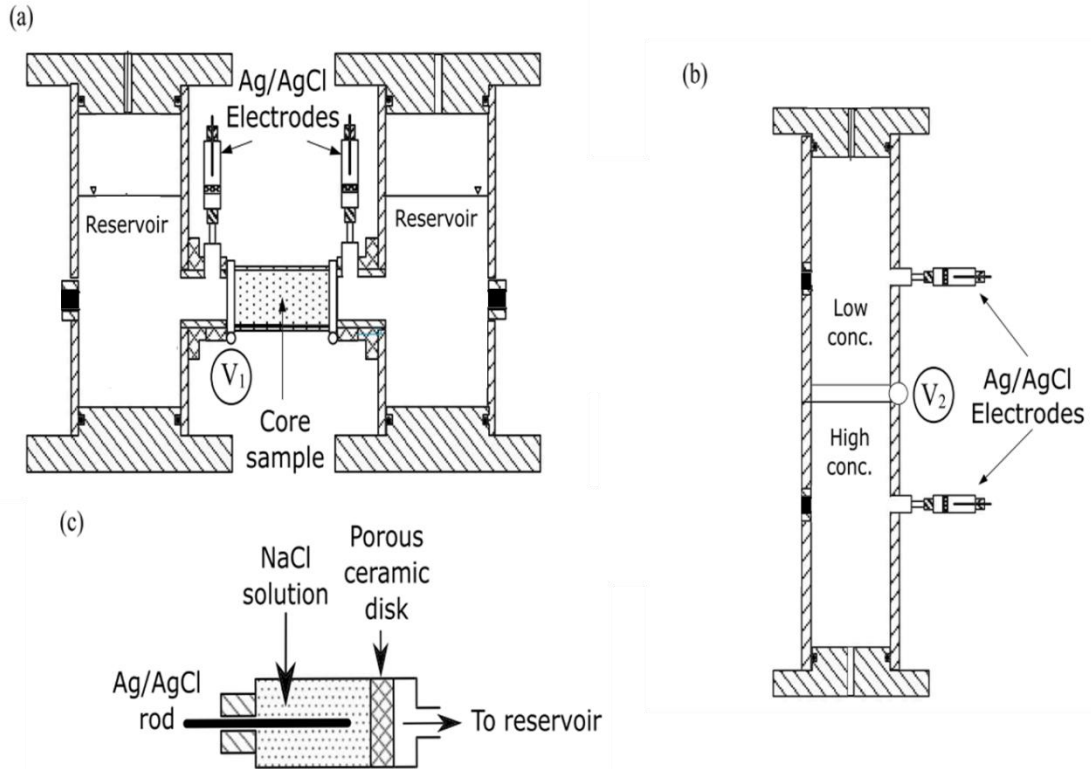


Figure 6.1: Experimental setup for the ED potential measurements. (a) Plug experiment, (b) column experiment and (c) cross-section through the electrodes (MacAllister et al., 2019).

6.3 Results

6.3.1 Column experiment:

Figure 6.2 shows the apparent column potential as a function of time for a period of 24 hours from when the valve was first opened. The column experiment was conducted prior to any plug experiments, and then repeated two further times after 9 and 13 plug experiments (Figure 6.3). The column experiments returned consistent electrical potentials and, based on these results and equation (6.1), the electrode potential was determined to be -36.54 ± 1.3 mV, given that the diffusion potential calculated using equation (6.2) and the data in Appendix C, is 9.04 ± 1.1 mV. Since the same electrodes and brines were used throughout this study, we assumed the electrode potential was the same in all plug experiments.

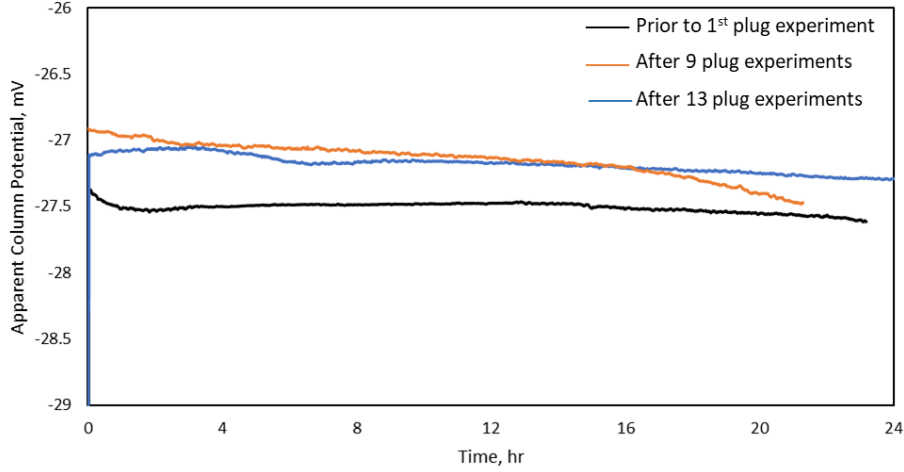


Figure 6.2: Apparent column potential versus time. The three lines represent the three repeat column experiments, conducted prior to the first plug experiment, and then repeated after 9 and 13 plug experiments.

6.3.2 ED potential at $S_w = 1$

A summary of the results of the plug experiments for the sandstone and shale samples at $S_w = 1$ is presented in Figure 6.3. The ED potential (ΔV_{ED}) was calculated based on equation (6.4) and the value of $\Delta V_C = -36.54$ mV determined in the previous section. The apparent plug potential as a function of time is shown in Figure 6.3a for all the samples used in this study. Figures 6.3b and 6.3c show the ED potential for all samples from this study after correction for electrode effects, compared against published experimental data for a range of sandstones, shaly sand, shale and carbonate samples saturated with NaCl brines and natural brines.

The ED potential for the sandstone samples from this study (coloured circles on Figure 6.3c) was diffusion-dominated (aligned with the solid line representing the diffusion dominated limit), consistent with the data obtained by Leinov and Jackson (2014) for sandstones saturated with NaCl brine. The shale samples showed less positive ED potentials and deviated from the diffusion-dominated limit, suggesting they were more exclusive than the sandstones.

The exclusion efficiency for the sandstone samples range from 0.008 to 0.03, which is very close to the exclusion efficiency of zero at the diffusion-dominated limit. These values are consistent with those

reported by Leinov and Jackson (2014) for sandstones saturated with NaCl brine. For the shale samples, we report exclusion efficiencies between 0.09 and 0.15, which are larger than the exclusion efficiency of the sandstone, but smaller than the values reported by MacAllister et al. (2019) for shale samples, which were in the range of 0.20 to 0.40. However, the permeability of the shale samples used in this study ranges between 0.5 and 1.5 md which is 300 times greater compared to the samples used by MacAllister et al. (2019).

We plot in Figure 6.4, the ED potential (ΔV_{ED}) and exclusion efficiency against sample permeability and note that both tend towards the diffusion dominated limit (the solid line in Figure 6.4b and $\varepsilon = 0$ in Figure 6.4c) as permeability increases (Figure 6.4).

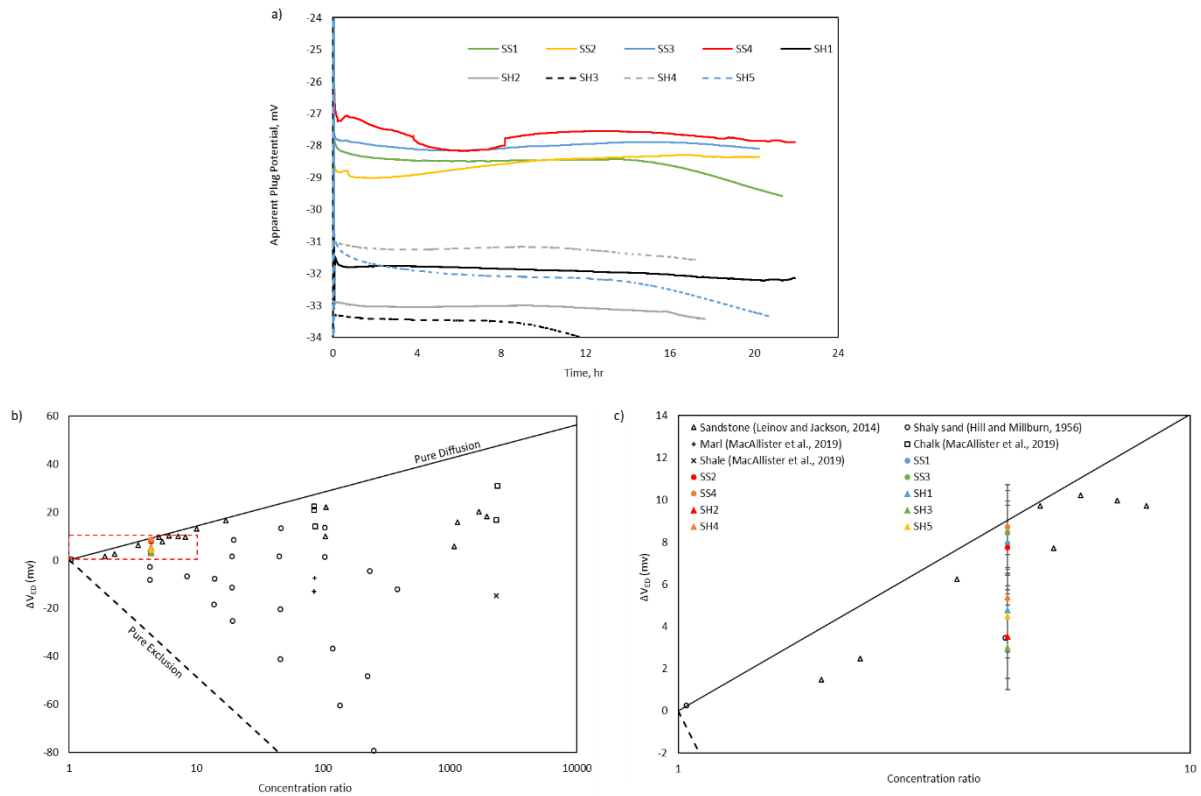


Figure 6.3: a) Apparent plug potential versus time for the nine samples used in this study at $S_w = 1$. b) ED potential versus concentration ratio for samples from this study compared against published data. Previous measurements on the sandstone sample (Leinov and Jackson, 2014) and the shaly sand (Hill and Milburn, 1956) were conducted with NaCl brines; the data presented by MacAllister et al. (2019) for chalk, shale and Marl samples were measured with natural ground water and seawater. c) The same data as (b) but focused on the dashed box in (b). The solid and dashed lines in (b) and (c) represent the pure diffusion and pure exclusion potentials, respectively, calculated using equation (6.2). The exclusion potential was calculated assuming negatively charged mineral surfaces exclude the negative ions in the brine, because the zeta potential of mineral surfaces of sandstones and shales is usually measured and modelled to be negative [e.g. Vinogradov et al., 2010; Walker and Glover, 2018].

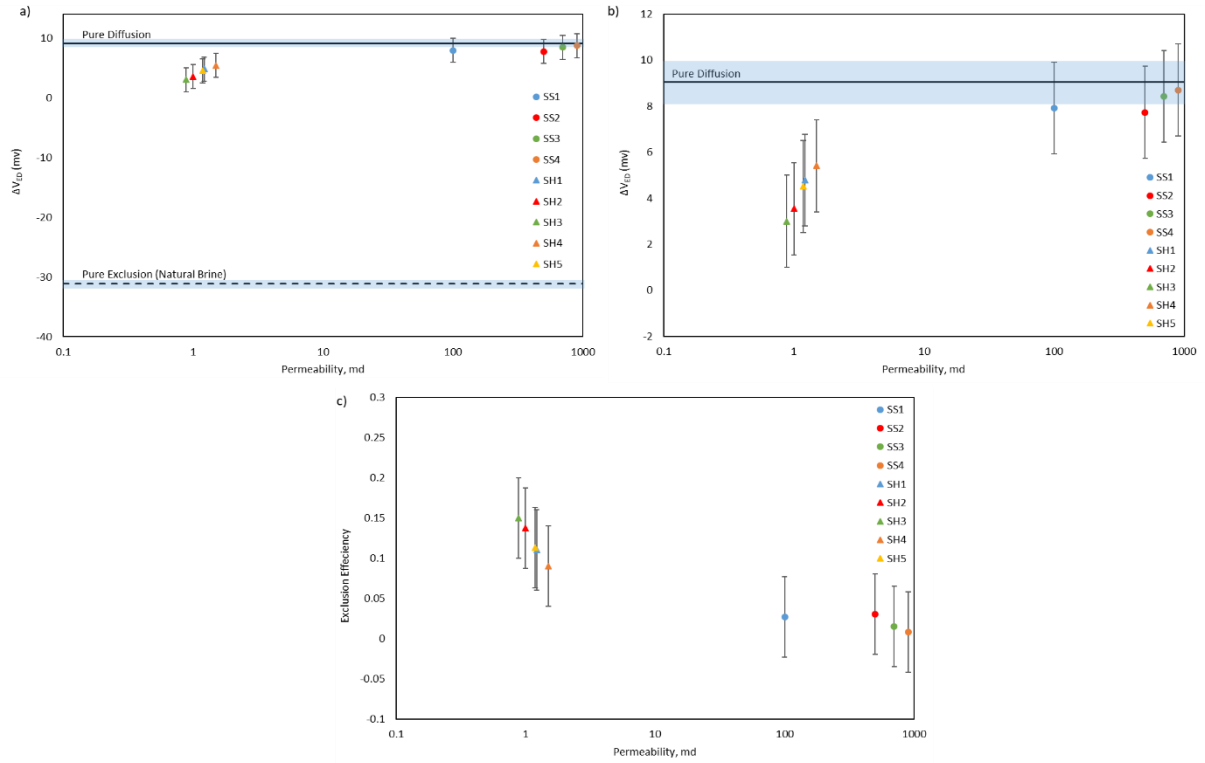


Figure 6.4: a) ED potential versus rock permeability for samples from this study. b) The same data as (a) but focused on ED potential between 12mV and -2 mV. c) Exclusion efficiency versus rock permeability. The solid and dashed lines in (a) and (b) represent the pure diffusion and pure exclusion potentials, respectively, calculated using equation (6.2). The exclusion potential was calculated assuming exclusion of negative ions. The blue shading indicates the error range in the calculated diffusion- and exclusion-dominated potentials.

6.3.3 ED potential at $S_w = 1 - S_{or}$ and $S_w = S_{wirr}$

The ED potential measurements reported in this section were obtained for the sandstone samples at the saturation end points: $S_w = 1 - S_{or}$ and $S_w = S_{wirr}$. Figure 6.5 shows the apparent plug potentials for the four sandstone samples when measured at fully saturated conditions ($S_w = 1$), residual oil saturation ($S_w = 1 - S_{or}$) and irreducible water saturation ($S_w = S_{wirr}$). The apparent plug potentials measured at $S_w = 1$ and $S_w = 1 - S_{or}$ were very similar in all samples; however, the apparent potential at $S_w = S_{wirr}$ in some samples was more or less negative than the value at $S_w = 1$ and $S_w = 1 - S_{or}$.

The ED potential after correcting for electrodes effects, and the corresponding exclusion efficiency, for the four sandstone samples, are reported in Figure 6.6 as a function of sample permeability. The ED potential and exclusion efficiency for all samples at $S_w = 1 - S_{or}$ was diffusion dominated, consistent

with the results at $S_w = 1$ (Figure 6.6a and b) and the findings of Ortiz et al. (1973), who suggested that ED potential is diffusion-dominated at high water saturation.

At $S_w = S_{wirr}$, the ED potential behaved differently compared to the measurements at $S_w = 1$ and $S_w = 1 - S_{or}$, especially for samples SS1 and SS4 (Figure 6.6b). For samples SS2 and SS3, the ED potential at $S_w = S_{wirr}$ was the same as the diffusion-dominated values obtained at $S_w = 1$ and $S_w = 1 - S_{or}$. However, it was more positive compared to the measurements at $S_w = 1$ and $S_w = 1 - S_{or}$ for sample SS4 (Figure 6.6b), and more negative for sample SS1. Moreover, these samples SS1 and SS4 are more exclusive, with sample SS4 excluding positive ions and sample SS1 is excluding negative ions.

The behaviour of sample SS1 is consistent with the results obtained by Ortiz et al. (1973), who suggested that the ED potential is exclusion-dominated towards negative ions at low water saturation, caused by a negative electrical charge on the surfaces of quartz and clay minerals. However, the behaviour of sample SS4 is not consistent with SS1 or the results of Ortiz et al. (1973), as the results are consistent with exclusion of positive ions from sandstone, which has not been observed before.

The exclusion efficiencies are presented in Figure 6.6c. The exclusion efficiency at $S_w = 1$ and $S_w = 1 - S_{or}$ was close to zero and consistent with diffusion dominated behaviour for all samples. At $S_w = S_{wirr}$, sample SS2 and SS3 were also diffusion dominated, but samples SS1 and SS4 were more exclusive towards negative and positive ions, respectively (Figure 6.6c).

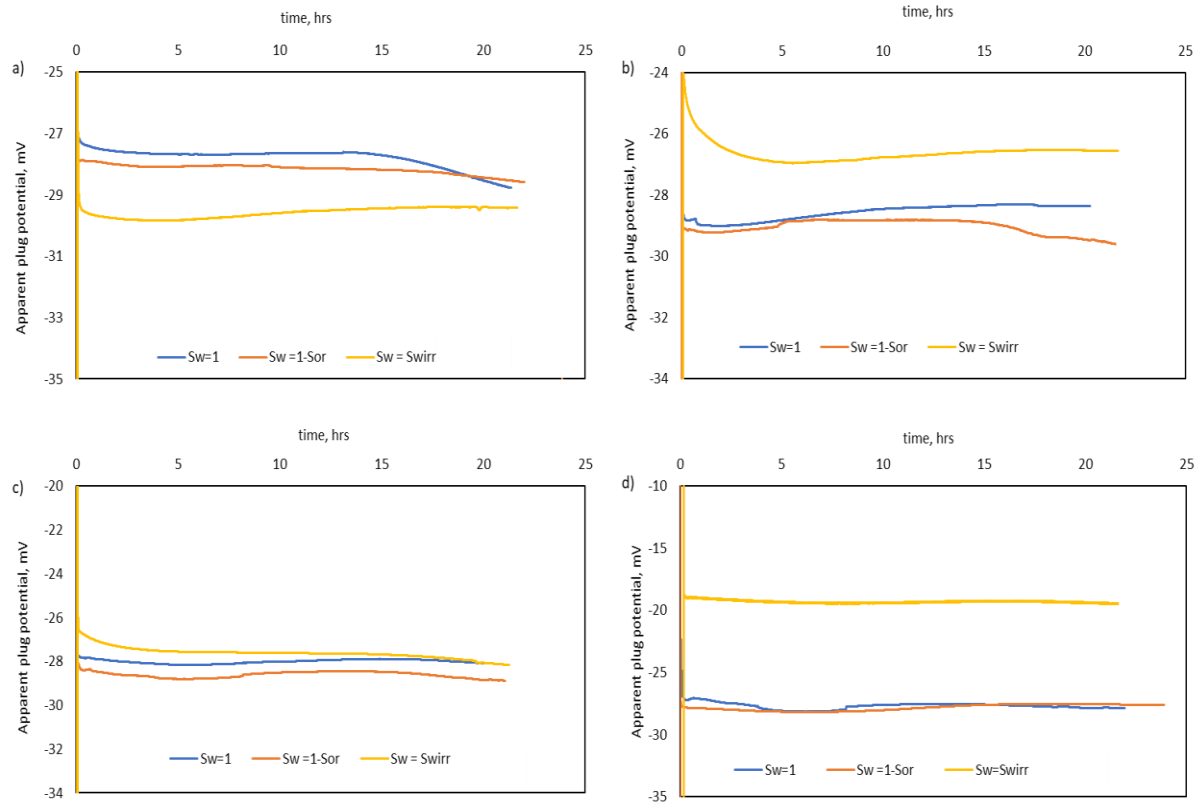


Figure 6.5: Apparent plug potential versus time for a) sample SS1, b) sample SS2, c) sample SS3 and d) sample SS4. The three data sets in each plot represent the three saturation conditions tested: fully saturated ($S_w = 1$), residual oil saturation ($S_w = 1 - S_{or}$) and irreducible water saturation ($S_w = S_{wirr}$).

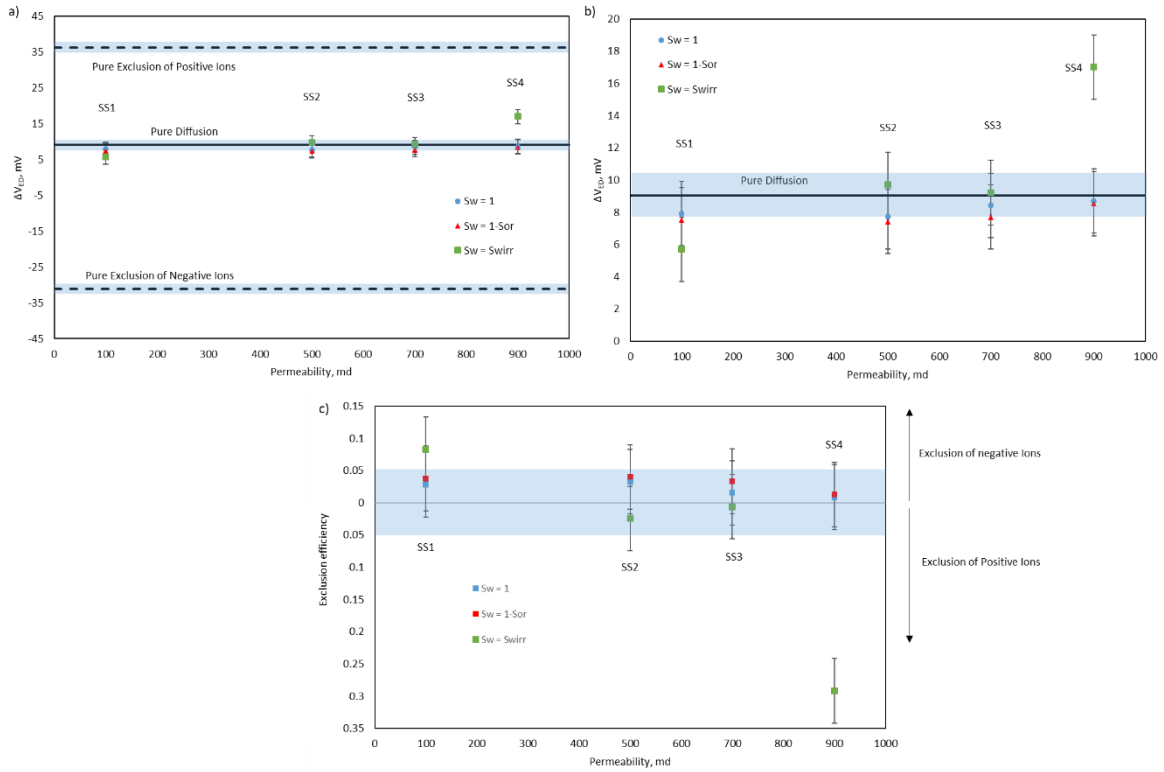


Figure 6.6: a) ED potential versus rock permeability for the sandstone samples. b) The same data as (a) but focused on ED potential between 0 mV and 20 mV. c) Exclusion efficiency versus rock permeability for sandstone samples. The upper part of plot (c) indicates exclusion of negative ions, while the lower part indicates exclusion of positive ions. The solid and dashed lines in (a) and (b) represent the pure diffusion and pure exclusion potentials, respectively, calculated using equation (6.2). The exclusion potential was calculated assuming excluding the negative (lower dashed line) and positive (upper dashed line) ions. The blue shadings denote the error range in the calculated diffusion- and exclusion-dominated potentials.

6.4 Discussion

The water saturated sandstone samples investigated here exhibited a diffusion-dominated ED potential, consistent with Leinov and Jackson's (2014) results for sandstones. In contrast, the shale samples were less diffusion dominated (Figure 6.3c), suggesting some charge exclusion, consistent with the behaviour observed in previous studies for shaly sand (Hill and Milburn, 1956) and shale samples (MacAllister et al., 2019). The contribution of the exclusion potential observed for the shale samples investigated here is lower compared to the results reported by MacAllister et al. (2019) due to higher permeability and hence, pore size of our samples compared to the ones investigated by MacAllister et al. (2019).

6.4.1 Relationship between permeability and charge exclusion

Westermann-Clark and Christoforou (1986) suggested that the ED potential is exclusion-dominated when the ratio r/L (pore throat radius to the thickness of the electrical double layer) is small and/or the surface charge is large, because the electrical double layer occupies a significant portion of the pore space; conversely, the ED potential is diffusion dominated when r/L is large and/or the surface charge is small. The samples used in this study were saturated with high salinity natural brine (2.2 M/L; Table 4.6); which yields an electrical double layer thickness on the order of $4.7 \times 10^{-10}\text{m}$ (Vinogradov et al. 2010).

Compared to typical pore sizes of sandstones (10^{-6}m) and shales ($10^{-8} - 10^{-7}\text{m}$) [Al-Jallad et al., 2017], r/L is large in this study, consistent with the small contribution of exclusion to the measured ED potentials. However, Figures 6.4b and c suggest an increase in charge exclusion with decreasing permeability. The permeability is related to the square of the pore-radius and, whilst the relationship between permeability and pore-radius in natural porous media is highly complex, smaller pore radius typically yields lower permeability. Consequently, lower permeability samples will have a smaller average r/L ratio and therefore, exhibit more exclusive behaviour, consistent with the data reported here.

6.4.2 Impact of water saturation on charge exclusion

The ED potential at high water saturation (i.e., $S_w = 1 - S_{or}$) was found to be diffusion-dominated, consistent with the single-phase measurements (Figure 6.6). These findings are also consistent with the results presented by Ortiz et al. (1973) who suggested that at high water saturations, the majority of the pore space is occupied by water so there is little difference in charge exclusion compared to fully water-saturated conditions.

Ortiz et al. (1973) reported that as the water saturation in their samples decreased, the ED potential approached the pure exclusion limit. We also found that the samples were more exclusive at a lower water saturation (i.e., $S_w = S_{wirr}$), especially in samples SS1 and SS4; however, the exclusion effect was much smaller than that observed by Ortiz et al. (1973). We suggest that this is a consequence of the difference in the experimental procedure between our study and that of Ortiz et al. (1973); they used

paraffin rather than crude oil and there was no aging. Consequently, their samples will have remained strongly water-wet, with water largely confined to the small pores and thin wetting layers in the larger pores, leading to efficient charge exclusion. Here, we used crude-oil and aged the samples, so the samples were likely less water-wet. Therefore, these results are clearly different compared to our assumptions made in Chapter 3 with regard to ED coupling coefficients.

The exclusion effect at $S_w = S_{wirr}$ was highest for sample SS4, although it has the highest permeability (1000 md), and hence the highest r/L . This conflicts with the trend of ED potential and exclusion efficiency observed at high water saturations (i.e., $S_w = 1$ and $S_w = 1 - S_{or}$). However, Sample SS4 has the lowest irreducible water saturation (0.08) compared to the other samples (0.1, 0.125 and 0.14 for samples SS2, SS3 and SS1, respectively); therefore, the charge density is highest in sample SS4 so the exclusion effect is also the highest (Westermann-Clark and Christoforou, 1986).

6.4.3 Electrical charge on the oil-brine interface

Sample SS4 is anomalous because it is a sandstone but excludes positive ions, suggesting a positive charge on the mineral surface. We suggest this arises because of the presence of oil-wet surfaces in the sample after aging: the polarity of the excluded ions depends on the polarity of the charged oil-brine interface in oil-wet areas of the pore space oil, but on the mineral-brine interface in water-wet areas of the pore space (Collini et al., 2020).

The polarity of the mineral-brine interface in these intact samples can be characterised by measuring the zeta potential using the streaming potential method (SPM; Vinogradov et al. 2010). We reported the zeta potential of the samples investigated in this study at $S_w = 1$ in chapter 5; Figure 6.7. Samples SS3 and SS4 exhibited negative zeta potentials, while samples SS1 and SS2 exhibited positive zeta potentials. These latter results are unusual but do not explain the exclusion of positive charge from sample SS4.

Characterisation of the charge at the oil-brine interface at $S_w = S_{wirr}$ is challenging (Collini et al., 2020; Collini and Jackson, 2021). Jackson et al. (2016) and Collini et al. (2020) reported the zeta potential of natural carbonate core samples when fully water saturated, and at the residual oil saturation after aging

in crude oil, measured using the SPM. They hypothesized that change in zeta potential (between $S_w = 1$ and $S_w = 1 - S_{or}$) is indicative of the polarity of the oil-brine interface when oil wets the mineral surfaces, and reported numerous experiments in which a positive oil-brine zeta potential was interpreted in samples saturated with complex natural brines, similar to the brine used here.

To further investigate the charge on the oil-brine interface in our experiments, we measured the zeta potential of the four sandstone samples at the residual oil saturation after aging with the crude oil using the experimental approach of Jackson et al. (2016) and Collini et al. (2020). The results are shown in Figure 6.7. For samples SS2 – SS4, the zeta potential became more positive after aging with crude oil, indicating a positively charged oil-brine interface, while sample SS1 became more negative after aging, indicating a negatively charged oil-brine interface. Assuming the charge on the oil brine interface is the same at S_{wirr} and S_{or} , these results are consistent with the ED potential data and suggest that the increased exclusivity at partial saturation is due to the charge on the oil-brine interface and that this may be positive or negative under the conditions of interest.

Sample SS4 has a negative mineral-brine interface but a positive oil-brine interface, and excluded positive ions, while sample SS1 has a positive mineral-brine interface but a negative oil-brine interface, and excluded negative ions. These results suggest that the oil-brine interface dominates charge exclusion at low water saturation, consistent with the fact that most of the pores are filled with oil and the majority of the mineral surfaces are oil wet.

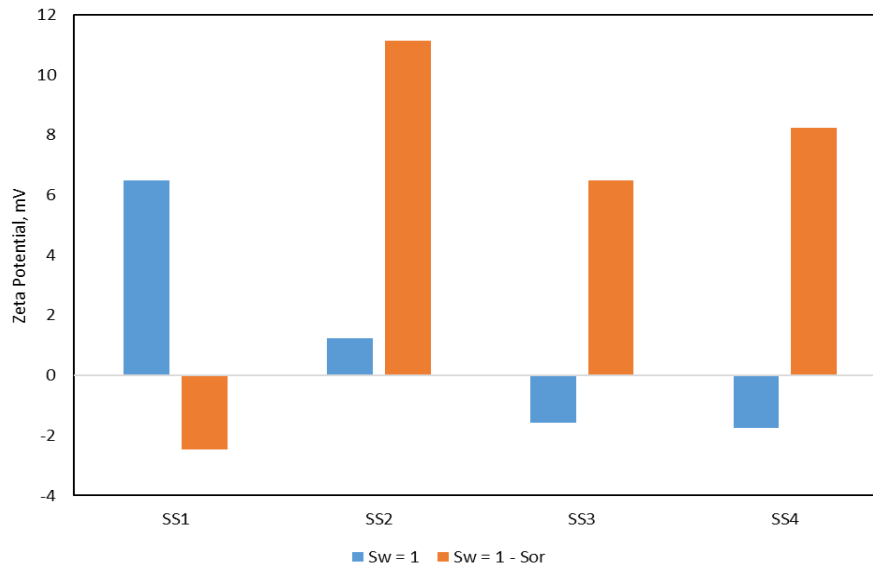


Figure 6.7: Zeta potential for the four sandstone samples (extracted from Figure 5.8).

6.5 Electrical Conductivity of Rock Samples

The electrical conductivity of sandstones at the three saturation states (Fully saturated, residual oil saturation and irreducible water saturation) was covered in section 5.5. This section presents the conductivity measurements for the shale layers following the same procedures described in section 5.5.

The rock conductivity measurements for the five fully saturated shale samples are summarized in Figure 6.8. Figure 6.8 shows the measured conductivity against sample porosity. These values are important to update the shale conductivity values used in the SP solver. It is obvious that the measured data fairly match with the trend predicted by Archie's equation (equation 3.15) currently implemented in the SP solver. Therefore, we will continue to use Archie's equation to predict the electrical conductivity for the shaly rock types.

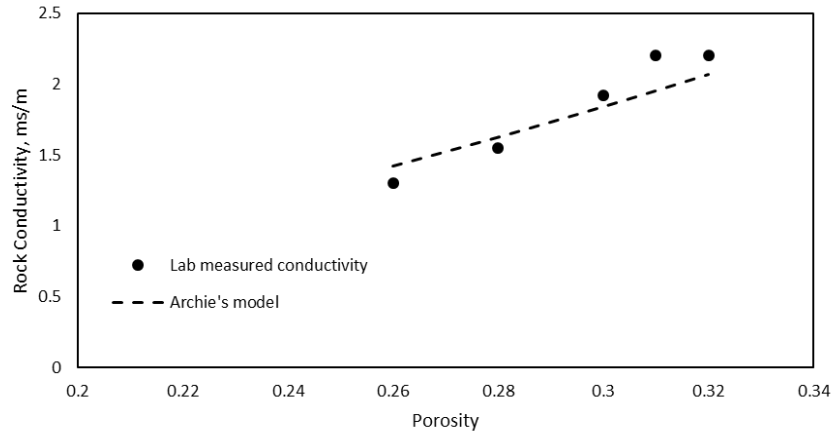


Figure 6.8: Rock conductivity versus sample porosity for the five shale samples. The dashed line represents Archie's equation (equation 3.15) with $m=1.8$ and $n=2$.

6.7 Conclusions

We measured the exclusion-diffusion (ED) potential that arises from a concentration gradient between FMB (2.2 Mol/L) and SW (0.5 M/L), in the four sandstone and five shale samples, collected from BGSU, at full water saturation and partial water saturation after aging with crude oil.

The ED potential was diffusion dominated for the fully water saturated sandstone and shale samples, with the shale samples slightly more exclusive consistent with previous studies. The importance of the exclusion component increased with decreasing permeability which we suggest is because the electrical double layer occupies relatively larger volume of smaller pores.

The ED potential measured at the residual oil saturation was consistent with the values measured at full water saturation, remaining diffusion-dominated because most of the pore space is occupied by water. However, at the irreducible water saturation, the effect was more exclusive and the polarity of the excluded ions was controlled primarily the polarity of the charged oil-brine interface. The oil-brine interfacial charge was interpreted to be positive in three of the four samples, consistent with some earlier studies and in contrast with the prevailing view that oil-brine interface is negatively charged. Samples with lower irreducible water saturation were found to be more exclusive due to the confinement of the

excess charge (ions) within smaller, water-occupied pores from which co-charges are efficiently excluded.

Finally, we reported the rock conductivity for the fully saturated shale samples. We found that the Archie's equation used in Chapter 3 fits measured data. The measured parameters reported in this chapter (EK coupling coefficient and rock conductivity), confirmed the importance of the experimental work for the SP feasibility assessment, represented in obtaining realistic values that are not consistent with the assumptions considered in Chapter 3. The parameters reported here will be used in Chapter 7 to update the SP solver predictions.

Chapter 7

Self-Potential Modelling in BGSU

7.1 Introduction

This chapter aims to numerically simulate the SP in the BGSU reservoir and to evaluate the pros and cons of the SP monitoring in this specific reservoir. So far, the work done on chapters 3, 4, 5 and 6 preambles the content of this chapter. Herein, we used the SP solver developed in chapter 3 and the BGSU dynamic model developed in chapter 4 to run the SP simulation. We ran several cases representing different production scenarios and reservoir conditions in order to obtain a good understanding of the behaviour of the SP.

Then, the coupling coefficient and rock conductivity measurements conducted in chapters 5 and 6 were used in the SP solver to calibrate the modelling results. The measured coupling coefficients were lower in magnitude, compared to the one used in chapter 3. Therefore, the post calibration SP signals were expected to be smaller in magnitude.

7.2 Self-Potential Modelling for the Low Connectivity (LCA) Model

The modelling approach presented in this section is based on the methodology described in chapter 3 that involves using correlations for predicting the electrical properties (rock conductivity and coupling coefficient). Before running the SP modelling, a grid refinement study was conducted to determine the optimum grid size that results in high resolution solutions around the well of interest. Then, SP modelling followed considering multiple production scenarios

7.2.1 Grid refinement study

It is important to note that the grid resolution in the near wellbore region must be significantly higher in models used to simulate SP than is typical in models used only to simulate fluid flow. The grid size used in the dynamic simulations described in chapter 4 was 50 m x 50 m x 0.8 m. We considered running

additional dynamic simulations in ECLIPSE by placing LGRs (Local Grid Refinements) around production wells according to Table 7.1. The grid refinement analysis was run in two stages: the horizontal direction and the vertical direction. The results of the LGR study are shown in Figure 7.1 for a snapshot of time 25 days before water breakthrough. Figure 7.1a shows the vertical profile of SP along well P6 (Figure 4.9 for the location), where we can see a convergence in the results for cases 2, 3, and 4 of the horizontal refinement and cases 3 and 4 of the vertical refinement. Figure 7.1c shows the maximum value of SP for each case plotted against case number where a clear convergence is observed beyond case 2 and case 3 for the horizontal and vertical refinements, respectively. Based on this analysis, the optimum grid size selected to be used further in this study was 13m x 13m x 0.2m.

Table 7.1: Cases for grid refinement study

Horizontal Refinement		Vertical Refinement	
Case	Size	Case	Size
1H	30m × 30m × 0.8m	1V	13m × 13m × 0.8m
2H	13m × 13m × 0.8m	2V	13m × 13m × 0.4m
3H	8m × 8m × 0.8m	3V	13m × 13m × 0.2m
4H	4m × 4m × 0.8m	4V	13m × 13m × 0.1m

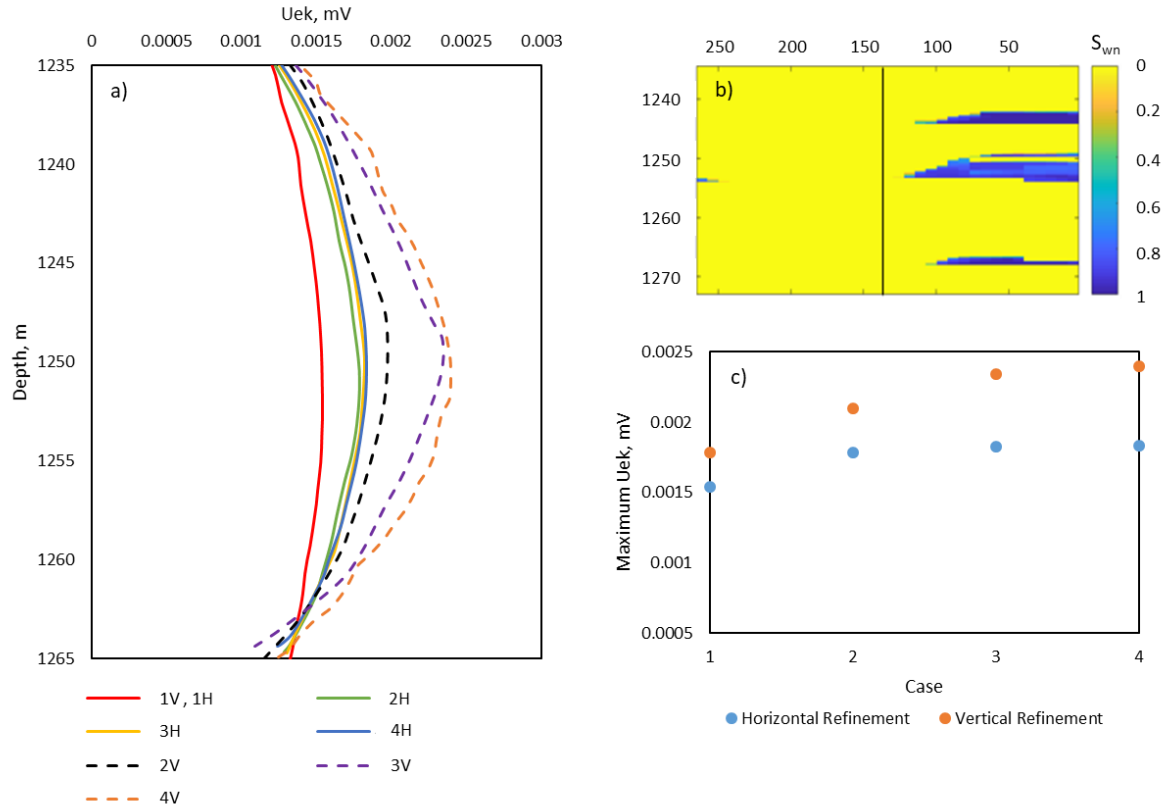


Figure 7.1: a) Vertical Profile of SP for different LGR cases for well P6. b) Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time, of normalised water saturation. c) Maximum SP at well P6 versus LGR case number.

7.2.2 Base case model results

We start by showing the results for the base case model which comprised five spot pattern water injection scheme with 500 m well spacing and an average production rate of 3000 STB/d per well. In this model, wells were completed with multiple perforation intervals such that water can approach each well from multiple locations across the vertical profile. Two different scenarios were simulated; re-injection of formation water (similar to the current approach followed in the WARA formation, SP = EK potential only) and sea water injection (SP = EK potential + ED potential).

7.2.2.1 Electrokinetic potential (EK)

In this case, the concentration of the water used for water flooding is equal to the formation water. Results are shown for well P6 which is completed across three intervals (A, B and C) as shown in Figure 7.3. The target production rate assumed in the dynamic model is 3000 STB/d, and it is allocated as follows: 600, 1500 and 900 STB/d for intervals A, B, and C, respectively. Figure 7.2 shows the water production as a function of time for the three intervals. Water breaks through first at interval B followed by A then C after 1155, 1186 and 1216 days of production, respectively.

Figure 7.3 shows snapshots at different time steps (before, at, and after water breakthrough) of the simulated EK potential, in the vertical cross-section A (Figure 4.9) and at the production well.

Figure 7.3 (a, b, and k) shows the results 50 days before water breakthrough (after 1000 days of production) when the waterfront is 45 m away from the well in interval B. The resulting SP signal at the production well is less than the assumed noise level of 0.1 mV (Chen et al., 2006; Jackson et al., 2012a), and there is no skewness in the profile towards any interval. The noise level considered in this study was established by the only field trial of SP conducted by Chen et al. (2006).

As water gets closer to the well, the shape of the profile starts to change and skews towards the middle of the reservoir (interval B). For example, Figure 7.3 (c, d, and k) shows the results 15 days before water breakthrough (after 1127 days of production) when the waterfront is 15 m away from the well in interval B. The SP signal at the production well remains lower than the assumed noise level; however, its maximum value is skewed towards interval B.

When water breaks through in interval B (after 1155 days of production), the maximum SP is aligned with the location of the water breakthrough in interval B [Figure 7.3 (e, f, and k)]. At the same time, the waterfront is approximately 10 m away from the upper interval A, and no SP anomaly is observed in the wellbore SP adjacent to interval A. The same behaviour was obtained 1 day before water breakthrough in interval A: there was no anomaly in the SP profile adjacent to the interval. The signals at the well remain very low in magnitude.

When water breaks through in interval A (after 1186 days of production), a peak in the SP signal occurs at the well at the location of interval A [Figure 7.3 (g, h, and k)]. Simultaneously, the waterfront is around 10 m away from the bottom interval C, and no SP anomaly is observed in the wellbore SP adjacent to interval C. We also ran the simulations for detailed time steps up to one day before the breakthrough of interval C, and the same behaviour was obtained: there was no anomaly in the SP profile adjacent to the interval. When water breaks through in interval C (after 1216 days of production), a clear peak in the SP signals occurs at the well at the location of interval C [Figure 7.3 (i, j, and k)]. The SP signals at the well remain very low in magnitude with a maximum value of 0.037 mV after the breakthrough in the three intervals.

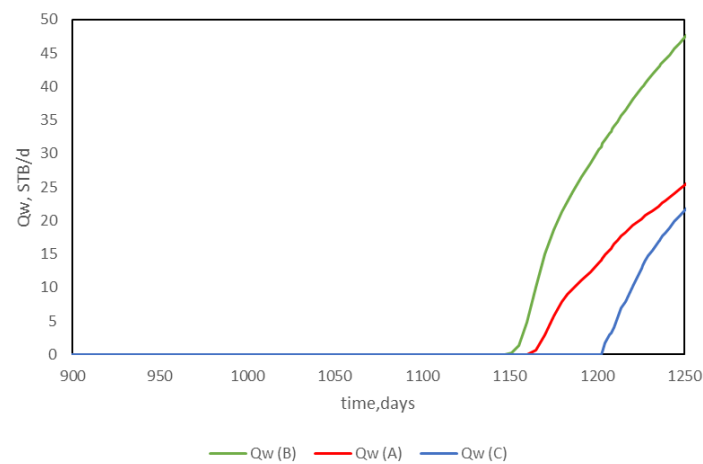


Figure 7.2: water production rate versus time for the three intervals.

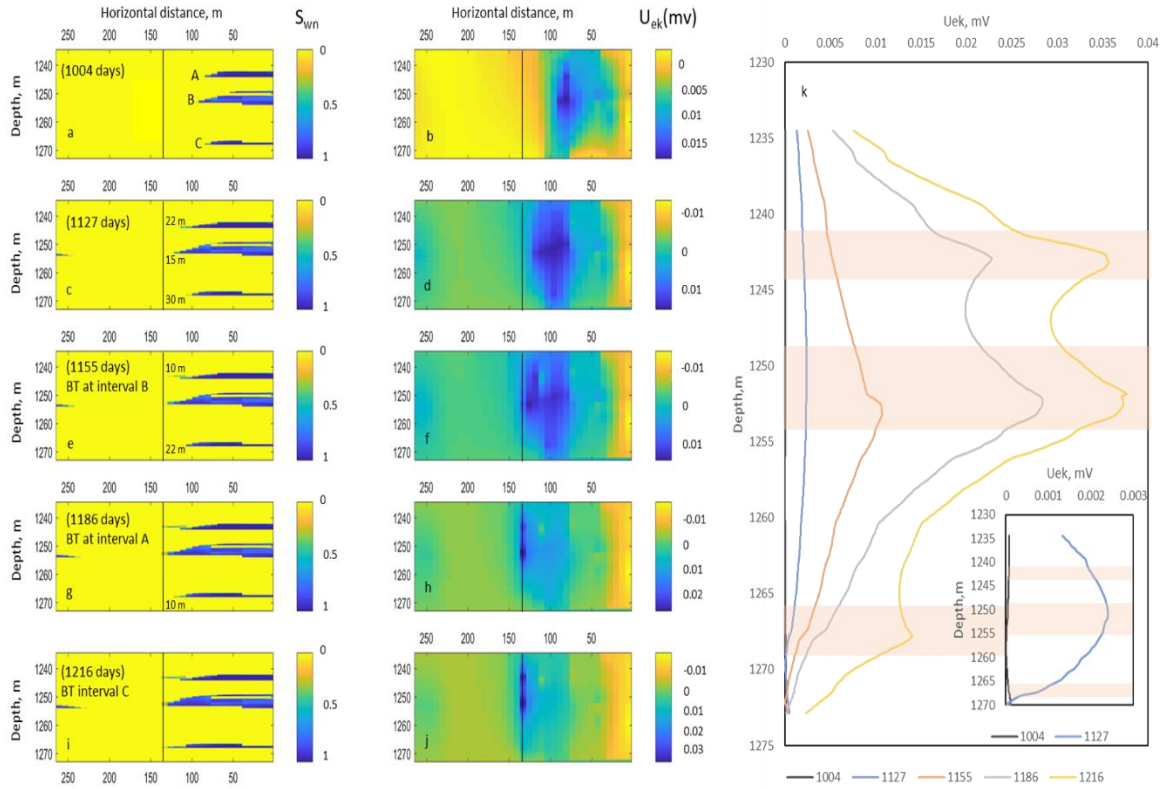


Figure 7.3: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time, of (a, c, e, g and i) normalised water saturation; (b, d, f, h and j) EK potential. The solid line in the vertical cross-sections represents the well location. Plot k shows the predicted EK potential along the well. Intervals A, B and C are highlighted with pink rectangular boxes.

7.2.2.2 Electrokinetic (EK) and exclusion-diffusion (ED) potentials

Next, we present the results of the overall SP including both EK and ED components (associated with injecting sea water for pressure support). Figures 7.4, 7.5 and 7.6 show snapshots at different time steps (at breakthrough of intervals B, A and C, respectively) of the simulated EK and ED components of the SP, and the total SP, in the vertical cross-section A (Figure 4.9) and at the production well. The three figures show that the concentration front lags approximately 60 m behind the waterfront. They also show that the EK potential peaks at the location of the waterfront while the ED potential peaks at the location of the concentration front. Moreover, the magnitude of the peak in ED potential is much higher than the peak of EK potential. As a result, the overall SP across the reservoir away from the production well is dominated by the ED potential (e.g., Figure 7.4e). However, at the production well, the overall SP is dominated by the EK potential (e.g., Figure 7.4f). The overall SP signals at the well remain very low in magnitude although the ED component was added in this case.

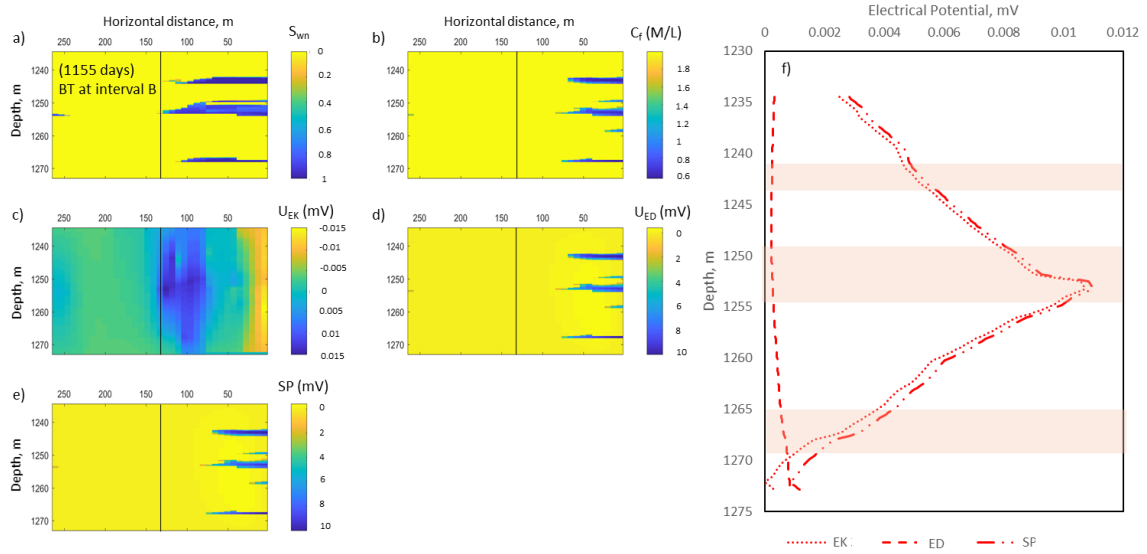


Figure 7.4: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time at the breakthrough of interval B, of (a) normalised water saturation; (b) concentration; (c) EK potential; (d) ED potential and (e) Overall SP. The solid line represents the production well P-6. Plot f shows the predicted EK, ED and overall SP potential along the well. Intervals A, B and C are highlighted with pink rectangular boxes.

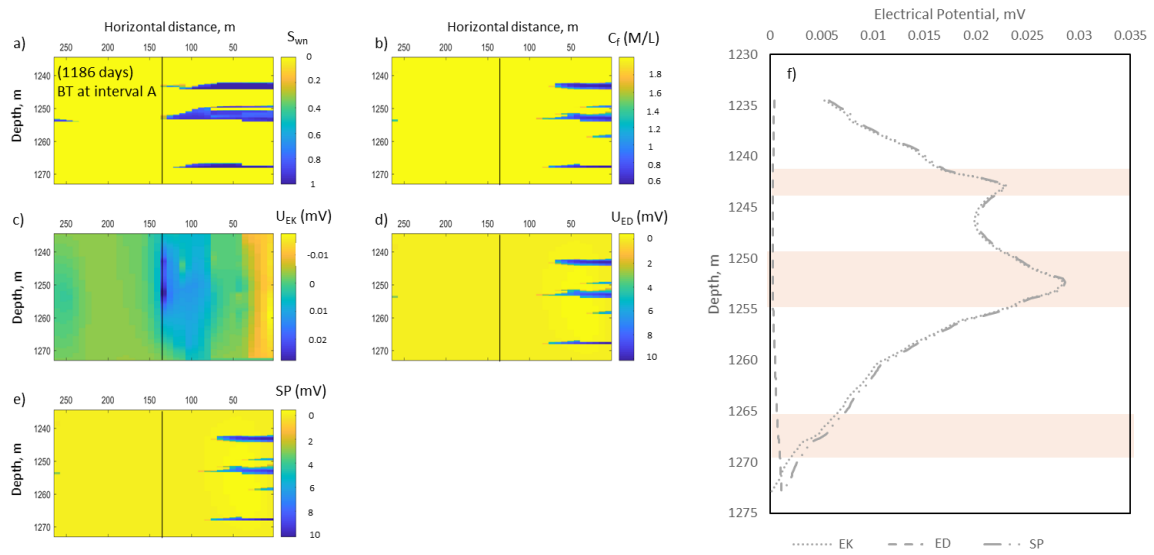


Figure 7.5: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time at the breakthrough of interval A, of (a) normalised water saturation; (b) concentration; (c) EK potential; (d) ED potential and (e) Overall SP. The solid line represents the production well P-6. Plot f shows the predicted EK, ED and overall SP potential along the well. Intervals A, B and C are highlighted with pink rectangular boxes.

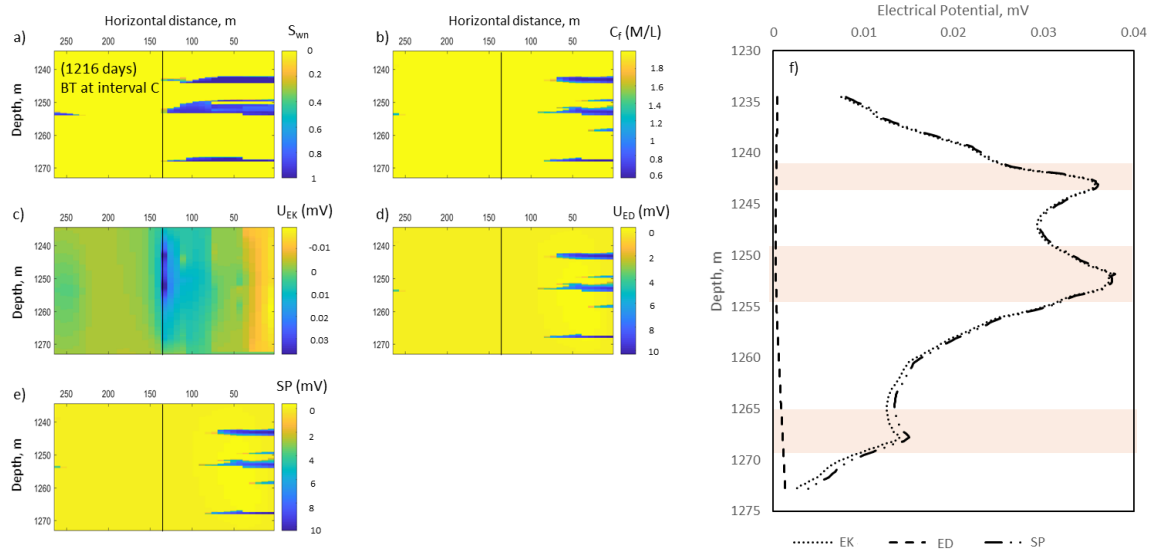


Figure 7.6: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time at the breakthrough of interval C, of (a) normalised water saturation; (b) concentration; (c) EK potential; (d) ED potential and (e) Overall SP. The solid line represents the production well P-6. Plot f shows the predicted EK, ED and overall SP potential along the well. Intervals A, B and C are highlighted with pink rectangular boxes.

7.2.3 Discussion

Three main observations can be highlighted from the results presented in the previous section. First, the magnitude of the SP signals at the production well is very low. The results were compared against an assumed noise level of 0.1 mV (Chen et al., 2006; Jackson et al., 2012b), and were found to be around 10 times lower than 0.1 mV at the time of water breakthrough. Second, no SP anomalies were observed in the wellbore SP prior to the breakthrough of intervals A and C (2nd and 3rd waterfronts). The third observation is the negligible contribution of the ED potential to the overall SP at the production well. This negligible contribution of ED potential is due to the lag of the concentration front behind the saturation front which is consistent with the findings from previous studies (Gulamali et al., 2011; Jackson et al., 2012b). Although the ED potential was observed to be dominating in some hydrology applications such as monitoring saline intrusion in coastal aquifers (MacAllister et al., 2019), the concentration ratio investigated in these studies ranged from 100 to 2000, compared to a concentration ratio of 2 in our case. Moreover, in hydrology fields the concentration gradient occurs between fully saturated porous systems while in our case, the diffusion occurs between the high water saturation area

behind the front and the low water saturation area ahead of the front. The first and second findings need further investigation to understand the reasons behind them, which is covered in the following subsections.

7.2.3.1 Magnitude of the self-potential signals

The main two factors affecting the magnitude of the SP signals (here, we focus on the EK potential as it is the dominating component at the well location) are i) the pressure gradient in the reservoir and ii) the water concentration. The first one is directly related to the EK potential (refer to ΔV vs. ΔP plots in chapter 5), while the second one is inversely related to it (Figure 2.10a; Chapter 2).

To investigate the pressure effect, we simplified the well completion to a single perforation interval (shut in interval A and C as shown in Figure 7.7). This simplifies the system in two-fold: first, getting a simple SP profile generated from one interval without any interference from other layers and second, forcing the total rate of 3000 STB/d through one interval instead of having it allocated in multiple intervals. The factors that affect the pressure gradient are i) the production rate and ii) the well spacing. Therefore, sensitivity analysis on production rate (3000, 6000, 10000 STB/d) and well spacing (500 m and 250 m) was performed.

Figure 7.8 shows vertical cross-sections (along section A in figure 4.9) of water saturation and EK potential at the time when the waterfront is around 20 m away from the production well for tested flow rates of 3000, 6000 and 10000 STB/d. These results are based on the 500 m spacing case. Similar to the multiple perforation scenario, the EK potential peaks (dark blue colour in Figures 7.8 [d, e and f]) at the location of the waterfront and decays away from the front toward the production well. The SP vertical profiles at the well are all skewed toward the producing zone (Figure 7.8g), which is a clear indication of the approaching water in this zone. It is clearly noticed that the EK signals predicted across the reservoir and at the production well are sensitive to the production rate. Higher production rates need more pressure drawdown which results in a higher EK potential. Figure 7.9a shows EK vertical profiles at the well at the breakthrough time for the three simulated flow rates. The peak in the profile of each rate is clearer and sharper at the producing interval, compared with Figure 7.8g. Figure 7.9b shows the

predicted EK potential across the producing zone as a function of time. Eventually, the signals are very low before water breakthrough, and as the water is approaching the well, the signals start to increase as water gets closer. The resulting signals at the production well (Figures 7.8g, 7.9) have higher magnitude than the multiple perforation interval scenario. However, they are lower than the assumed noise level of 0.1 mV (Chen et al., 2006; Jackson et al., 2012a) even at the time of water breakthrough and at the higher rates.

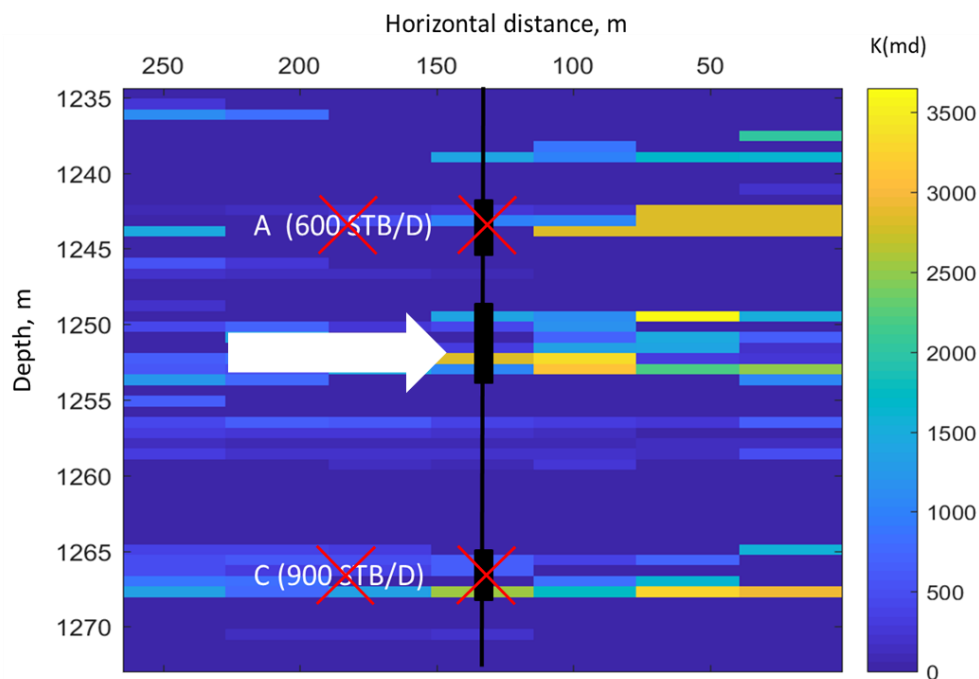


Figure 7.7: Vertical permeability cross-section (along section A [figure 4.9]) for the simplified completion of well P6.

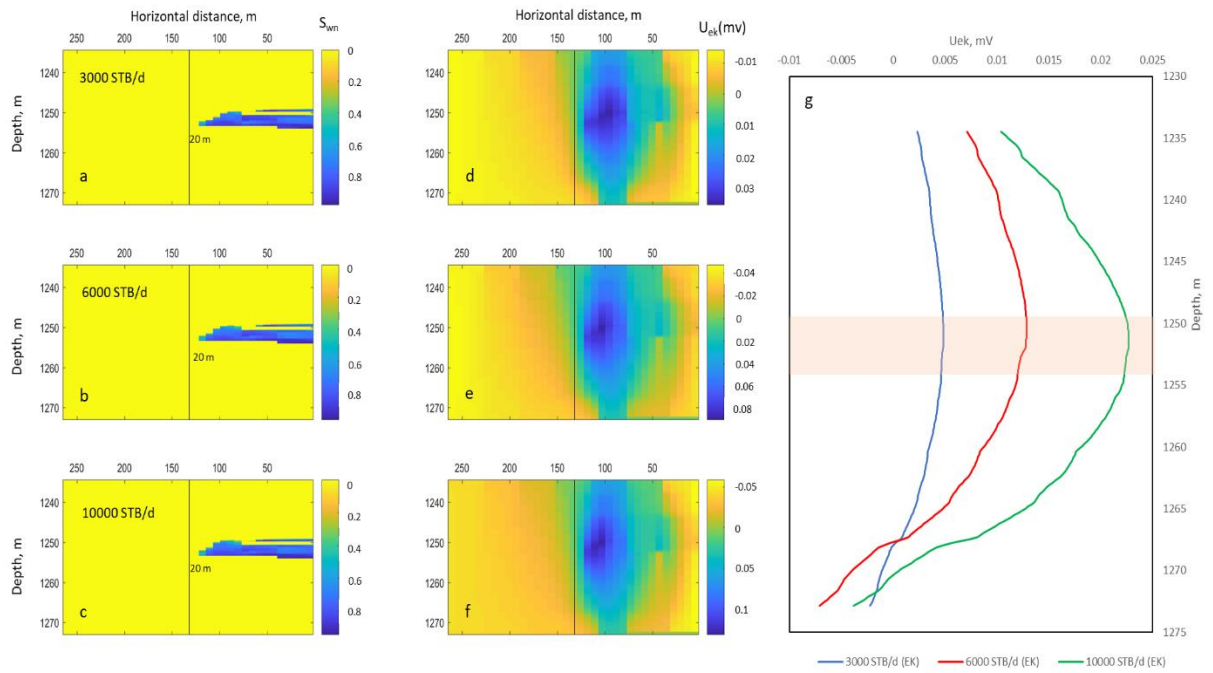


Figure 7.8: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time, of (a, b and c) normalised water saturation; (d, e and f) EK potential for the three flowrates of 3000, 6000 and 10000 STB/d. The solid line represents the production well P-6. Plot g shows the predicted EK potential along the well. Intervals A, B and C are highlighted with pink rectangular boxes.

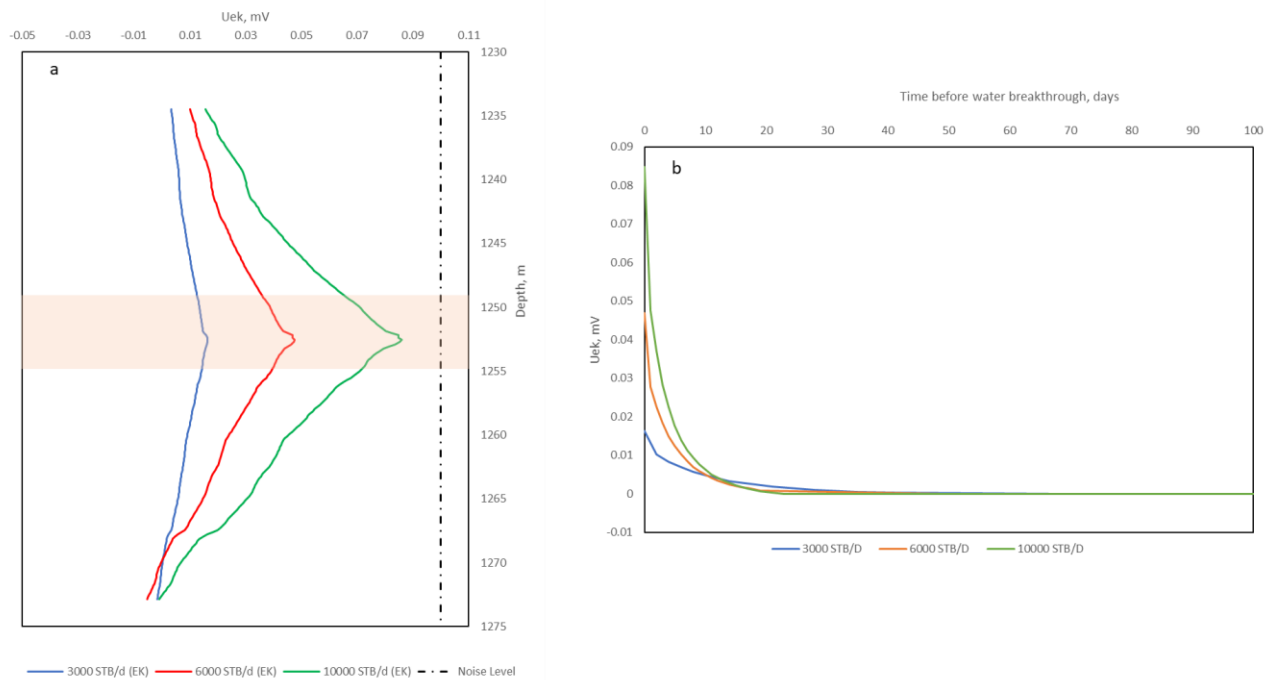


Figure 7.9: a) Vertical profile of the EK potential at the production well at the time of water breakthrough. The highlighted interval represents the perforation interval. b) EK potential across the producing zone as a function of time before water breakthrough.

The other factor affecting the pressure gradient is the well spacing. A sensitivity analysis on the well spacing (500 m and 250 m) was run considering the single completion model. Results are shown in Figure 7.10 for the 3000 STB/d case. As well spacing decreases, the predicted signal at the well increases due to the increase of the pressure gradient. The signals are also less than the assumed noise level of 0.1 mV. The only scenario where the signals increase over the assumed noise level is when simulating a production rate of 10000 STB/d with 250 m spacing. However, this scenario is impractical for BGSU based on the current production performance.

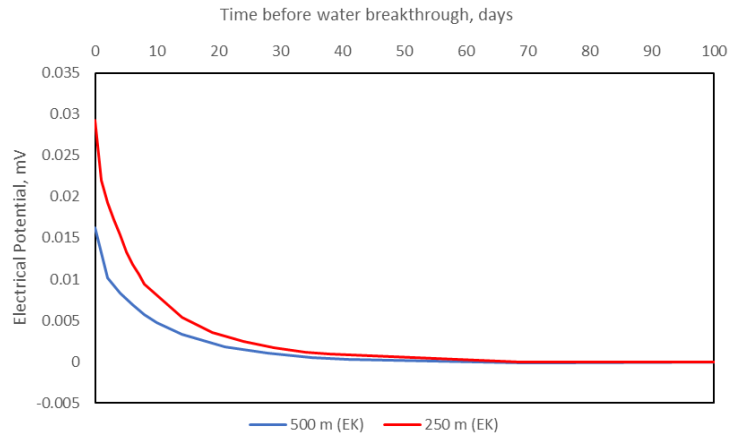


Figure 7.10: EK potential versus time before water breakthrough for the 3000 STB/d case with 500 m and 250 m spacing.

The flow rate and well spacing sensitivity analysis suggest that the pressure gradient has a big impact on the magnitude of the SP signals causing it to be very low. We tried to increase the pressure gradient even beyond the acceptable limits in the field but even then, the signals were low. The low pressure gradient is mainly due to the high permeability of the sand channels (up to 4 Darcy according to Figure 7.7).

The other factor that could affect the magnitude of the signals is the water concentration. The water concentration is inversely related to the EK coupling coefficient, so decreasing it can cause an increase in the EK coupling coefficient and hence, increase the EK potential. This particular effect was investigated by assuming a constant concentration across the whole reservoir, therefore, only having the EK component, and varying the concentration from 2 M/L (base case) to lower values of 1, 0.5 and 0.1 M/L. This test was run on the single perforation model. Figures 7.11 shows the maximum EK potential at well P6 at two different time steps (when the front is 10 m away and at the breakthrough) for the four test values of water concentration. The results suggest that signals may cross the noise level only at the lowest investigated concentration of 0.1 M/L which is twenty times lower than the reservoir brine concentration. This implies that, for the given reservoir and production conditions, the reservoir brine needs to be very fresh in order to show a positive SP response at production wells prior to the

breakthrough. Though, for this specific reservoir, the concentration effect on the magnitude of the signals is not of a high impact as the pressure effect.

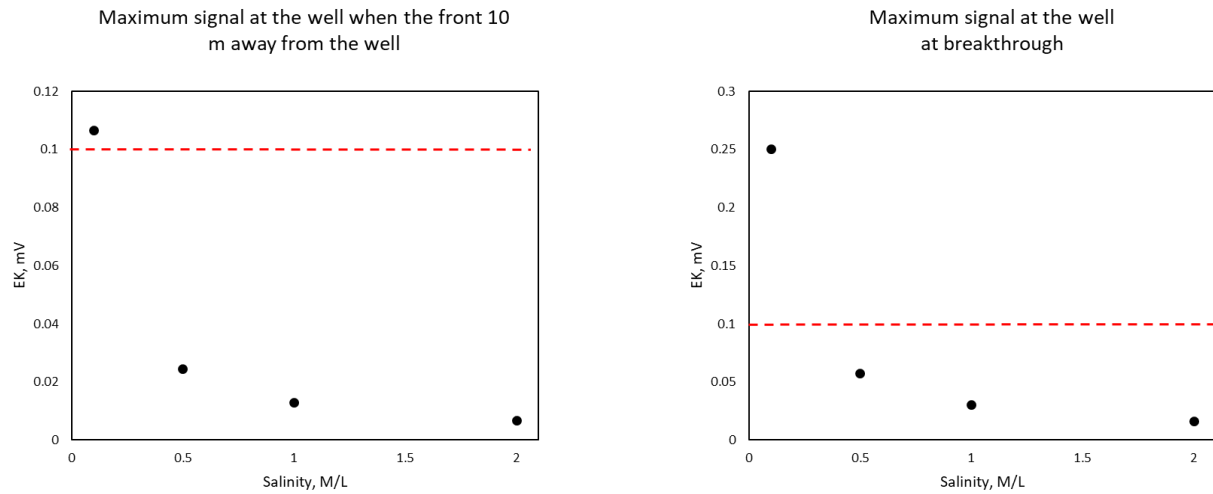


Figure 7.11: Maximum EK potential at the well at two different time steps (before and at water breakthrough) versus reservoir brine concentration.

The investigations on the pressure gradient and salinity effects on the magnitude of the SP signals revealed that the low magnitude is mainly due to the low pressure gradient as a result of the very high permeability.

To prove that, we hypothesized a case where the reservoir permeability is reduced by a factor of 10 with the same base case model assumptions except that the perforated intervals are only two in this case (interval B and C as shown in Figure 7.12).

Figure 7.12 shows snapshots at different time steps (before, at, and after water breakthrough) of the simulated EK potential, in the vertical cross-section A (Figure 4.9) and at the production well. Figure 7.12 (a, f, and k) shows the results 25 days before water breakthrough when the waterfront is 45 m away from the well in interval B. The resulting EK potential at the production well is less than the assumed noise level (Chen et al., 2006; Jackson et al., 2012a).

Figure 7.12 (b, g, and l) shows the results 10 days before the water breakthrough, when the waterfront is 20 m away from the well in interval B. The EK signal at the production well is higher than the assumed noise level, and its maximum value is skewed towards interval B. When water breaks through

in interval B [Figure 7.12 (c, h, and m)], the maximum EK is aligned with the location of the water breakthrough in interval B. At the same time, the waterfront is approximately 30 m away from the bottom lower interval C, and no SP anomaly is observed in the wellbore SP adjacent to interval. The same behavior was obtained one day before the water breakthrough in interval C: there was no anomaly in the SP profile adjacent to the interval [Figure 7.12 (d, i, and n)]. When water breaks through in interval C, a peak in the SP signal occurs at the well at the location of interval C [Figure 7.12 (e, j, and o)].

In the hypothesized case tested here, the SP signal at the production well of interest exceeds the assumed noise level of 0.1 mV around 10 days before water breakthrough and the maximum SP signal is located in the stratigraphic interval through which the fastest waterfront (interval B) is flowing towards the wells [Figures 7.12(b, g and i)]. Thus, the SP signal indicates an encroaching waterfront and identifies its location. However, there is no SP anomaly associated with the later breakthrough in the other reservoir interval (interval C), consistent with the findings from the original high permeability base case.

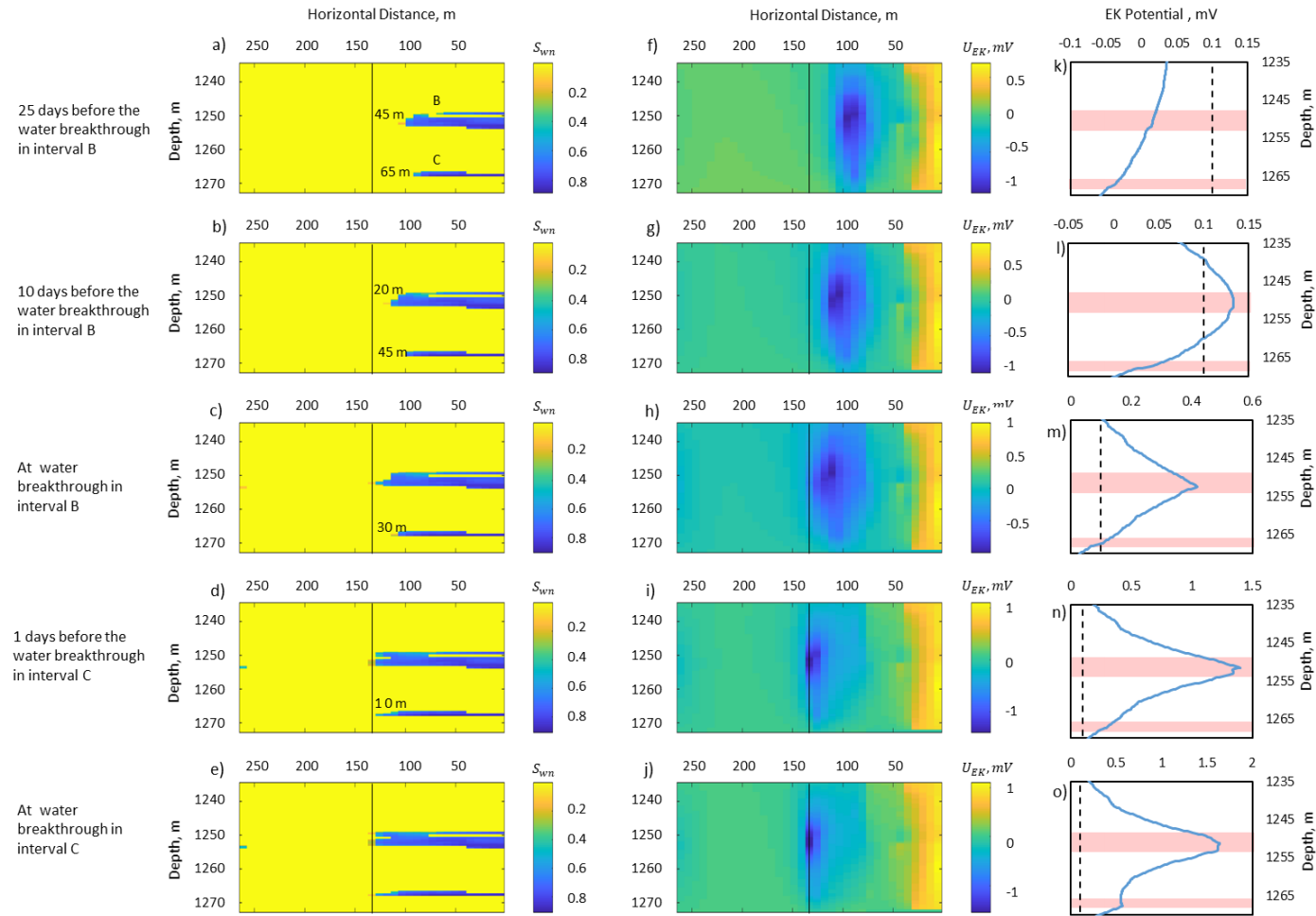


Figure 7.12: Vertical cross-sections along plane A in Figure 4.9, showing a snapshot in time, of (a through e) normalised water saturation; (f through j) EK potential. The solid line represents the production well P-6. Plots (k through o) show the predicted EK potential along the well. The vertical dashed line represents an assumed noise level of 0.1 mV. The perforated intervals are highlighted with pink rectangular boxes.

7.2.3.2 Absence of self-potential anomalies in subsequent waterfronts before breakthrough

In this section, we will investigate the absence of any SP anomalies for the second and third intervals (intervals A and C) before water breakthrough. We believe this is because the SP generated in these intervals is masked by the high SP generated in the interval that had a water breakthrough earlier (interval B). The high SP generated in the interval having the fastest front dissipates to the bounding layers and the rate of this dissipation is governed mainly by the electrical conductivity of these layers. The bounding layers in this case are water saturated shale which are more electrically conductive, compared to producing oil bearing intervals.

To prove this, we run the SP solver for the same base case reservoir model but with ten times reduced rock conductivity in the shale layers (rock types 1 and 2). In this case, we clearly obtained three distinct peaks aligned with the water movement in the A, B, and C reservoir intervals (Figure 7.13). Comparing the results from both models (Figure 7.13b and c), we observe (i) a higher magnitude of SP with reduced shale conductivity and (ii) the detection of the separate waterfronts approaching the well in each interval with reduced conductivity.

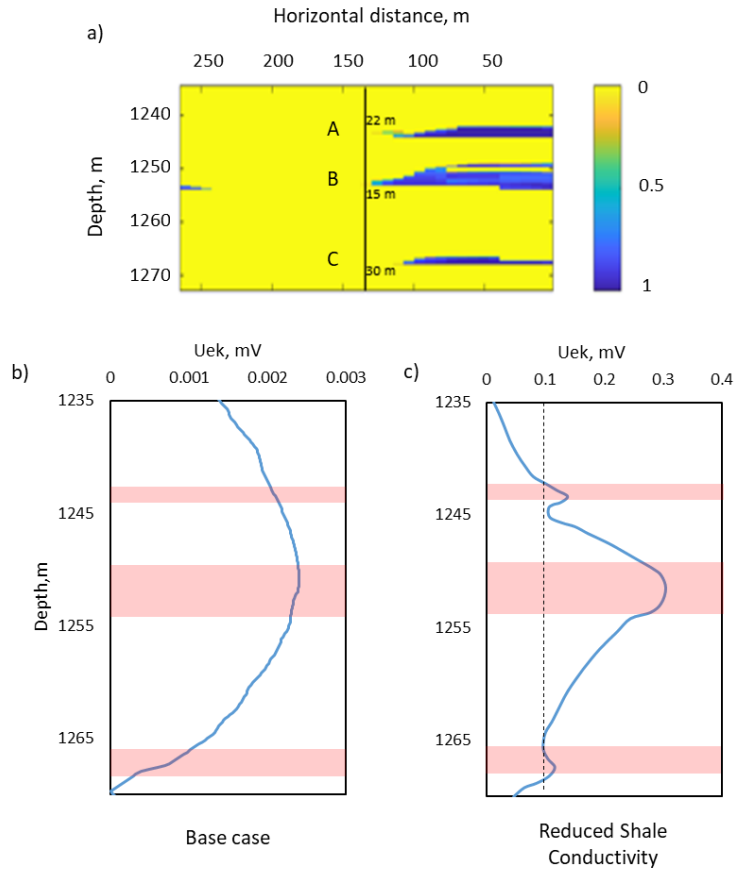


Figure 7.13: a) Vertical cross-sections of normalised water saturation along plane A in Figure 4.9, showing a snapshot in time 25 days before water breakthrough at the production well. The solid line represents the production well P-6. b) and c) Predicted EK potential along the well for the base case model and the reduced conductivity model, respectively. The pink rectangles represent the three reservoir layers and the dashed line represents an assumed noise level of 0.1 mV.

7.3 Calibration

The results presented in the last section were obtained based on the methodology described in chapter 3 which involves using empirical correlations to predict the electrical properties (coupling coefficients and rock conductivity). In this section, the experimental results obtained in chapters 5 and 6 were used to calibrate the modelling results.

First, we started by calibrating the case which involves the EK potential only (associated with assuming re-injecting formation water for pressure support). The EK coupling coefficients reported in chapter 5 (measured with FMB at $S_w = 1 - S_{or}$ shown in Figure 5.9) were input into the solver as a single value for

each rock type. These coefficients are smaller in magnitude compared to the correlation's predictions. Therefore, we expected the EK potential predictions to be smaller in magnitude after the calibration. However, the change in the polarity of the coupling coefficients with rock type has not been investigated before (Saunders et al., 2008; Gulamali et al., 2011; Jackson et al., 2012b; Ijioma, 2016), so the effect is yet not clear. At partial saturations ($1-S_{or} > S_w > S_{wirr}$), we continued to use the model by Jackson et al. (2012) described in equation (3.18). For the electrical conductivity of the partially saturated rock types (RT 3, 4, 5 and 6), an updated version of Archie's equation (updated saturation and cementation exponents as shown in chapter 5) was implemented instead of the version presented in chapter 3 (equation 3.15). On the other hand, for the fully water saturated shaly rock types (RT 1 and 2), we continued using the Archie's equation (equation 3.15).

The pre and post calibration results for this case are shown in Figure 7.14. Figure 7.14 shows snapshots at two different time steps (before and at the water breakthrough) of the simulated EK potential at the production well. It is obvious in Figure 7.14 (b and d) that the EK signals after the calibration are smaller in magnitude as expected due the lower EK coupling coefficients.

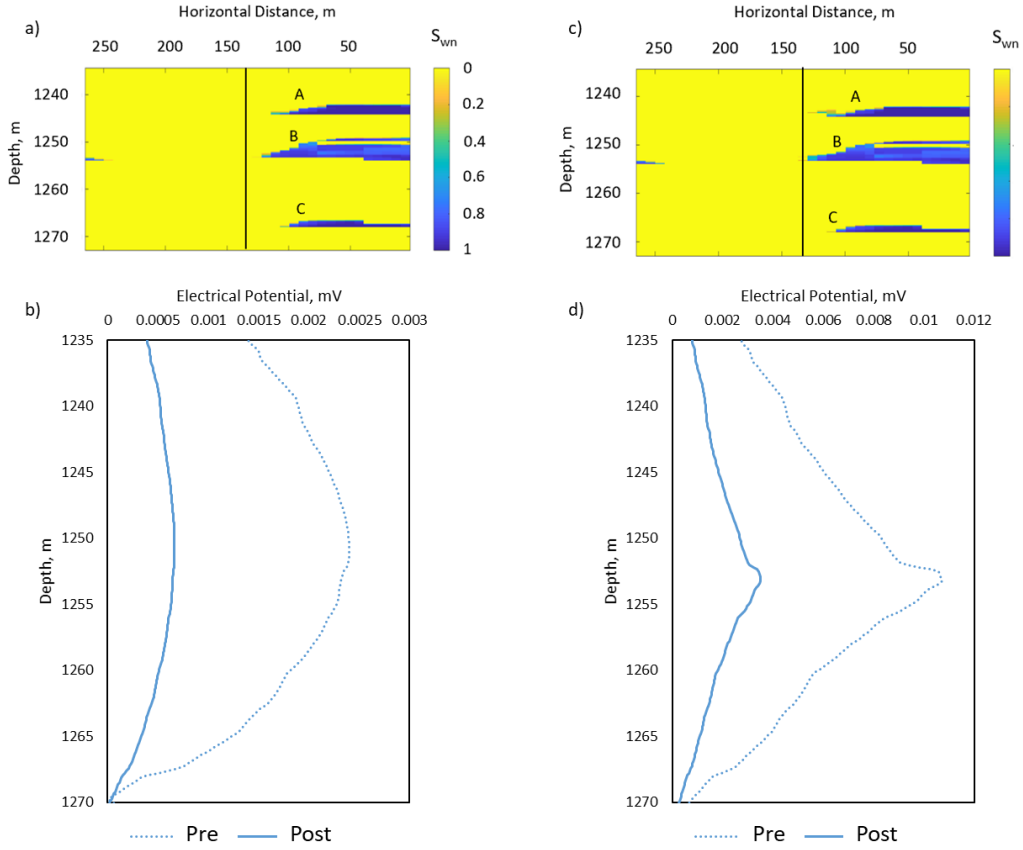


Figure 7.14: a) and c) Vertical cross-sections of normalised water saturation along plane A in Figure 4.9, showing a snapshot in time before and at water breakthrough at the production well, respectively. The solid line represents the production well P-6. b) and d) Predicted EK potential along the well before and at water breakthrough, respectively.

Next, we calibrated the other case where the SP signals comprises both EK and ED potentials (associated with assuming injecting seawater for pressure support). This case involved variation of water concentration across the reservoir with a maximum value of that of FMB and a minimum value of that of seawater. Therefore, to calibrate the EK potential, it is required to define EK coupling coefficients between the maximum and minimum concentrations. However, in chapter 5, we only measured these coefficients at the two extreme points (FMB and SW as shown in Figure 5.9). Hence, we assumed that the EK coupling coefficients vary linearly between the two extreme points. This approach was used to model the EK coupling coefficient at $S_w = 1 - S_{or}$. At partial saturations ($1 - S_{or} > S_w > S_{wirr}$), we continued to use Jackson et al. (2012) model described in equation (3.18).

To calibrate the ED potential, the exclusion efficiency needs to be defined for each rock type. For the fully saturated shale samples, our results from chapter 6 showed that the exclusion efficiency is about

0.1, which implies lower exclusion effect compared to our current assumption of 0.4. Therefore, we continued to use equation (3.21) to (3.26) with the new measured exclusion efficiency to calculate the ED coupling coefficients for these rock types (RT 1 and 2). For the permeable rock types (RT 3, 4, 5 and 6), our results from chapter 6 showed that the exclusion efficiency was found to be almost zero at $S_w = 1 - S_{or}$, consistent with our assumptions in chapter 3. However, at $S_w = S_{wirr}$, the rocks are slightly exclusive (maximum value was 0.27), in contrast to the assumption of exclusion domination made in chapter 3. Moreover, we showed in Chapter 6 that the polarity of the oil-brine interface affects the type of ions to be excluded from the pore space (e.g., Sample SS1 had a negative oil brine interface causing the negative ions to be excluded while other samples [SS2, SS3 and SS4] have positive oil brine interface causing the positive ions to be excluded). This effect was not accounted for during the development of the SP solver in chapter 3, where it was assumed that the charged interface is always negative leading to negative ion exclusion (Equation 3.22 for the exclusion dominated ED potential). This assumption applies to rock type 3 (represented by sample SS1). However, this is not the case for the other rock types. To account for the variation of the polarity of the excluded ions and the slight exclusion effect observed at $S_w = S_{wirr}$ (compared to the assumption of pure exclusion considered in chapter 3), the ED coefficient equation (equation 3.26) needs to be adjusted as follows

$$C_{ED}(S_w) = \varepsilon_r(S_w) \cdot (C_{ED}|_{S_{wirr}} - C_{ED}|_{1-S_{or}}) + C_{ED}|_{1-S_{or}} \quad (7.1)$$

$$C_{ED}|_{1-S_{or}} = C_{ED}|_{ed} = -8.61 \times 10^{-2} \frac{(2t_{Na} - 1)T}{C_f} \quad (7.2)$$

$$C_{ED}|_{S_{wirr}} = |\varepsilon_{S_{wirr}}|(C_{ED}|_{ee} - C_{ED}|_{ed}) + C_{ED}|_{ed} \quad (7.3)$$

$$C_{ED}|_{ee} = \begin{cases} -8.61 \times 10^{-2} \frac{T}{C_f} & \text{for negative ions exclusion} \\ 8.61 \times 10^{-2} \frac{T}{C_f} & \text{for positive ions exclusion} \end{cases} \quad (7.4)$$

Where $C_{ED}|_{S_{wirr}}$ and $C_{ED}|_{1-S_{or}}$ are the ED coupling coefficients at saturation end points. Our results showed the ED potential is diffusion dominated at $S_w = 1 - S_{or}$ and hence, equation (3.22) [the same as equation 7.2] can be used to calculate the coupling coefficients. $C_{ED}|_{S_{wirr}}$ can be obtained based on the exclusion-dominated and diffusion-dominated coupling coefficients ($C_{ED}|_{ee}$ & $C_{ED}|_{ed}$) and the

exclusion efficiency reported at S_{wirr} ($\varepsilon_{S_{wirr}}$) in Figure 6.6. The saturation dependent exclusion efficiency $\varepsilon_r(S_w)$ can be obtained by the model by Jackson et al. (2012) described in equation (3.27).

The pre and post calibration results for this case are shown in Figure 7.15. Figure 7.15 shows snapshots at two different time steps (before and at the water breakthrough) of the simulated EK, ED and SP at the production well. It is obvious in Figure 7.15 (b and d) that the signals after the calibration are smaller in magnitude as expected due the lower EK coupling coefficients and the lower exclusion effect in the shale layers and the oil zones (S_{wirr}).

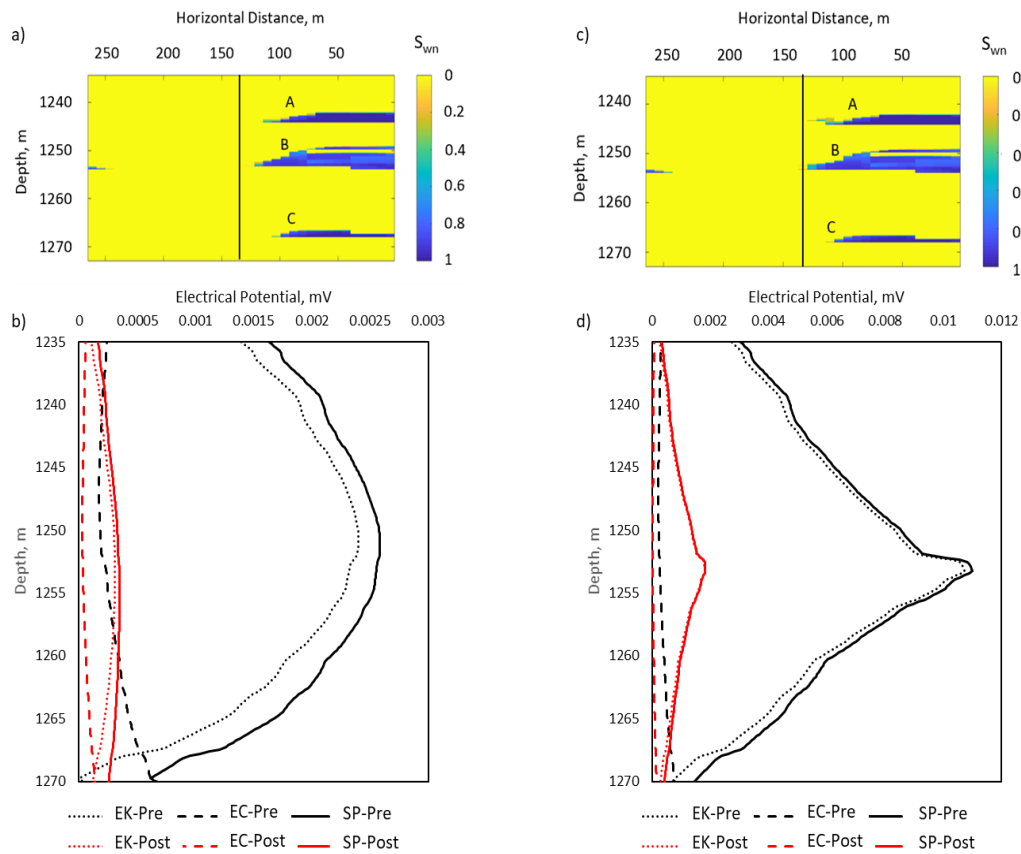


Figure 7.15: a) and c) Vertical cross-sections of normalised water saturation along plane A in Figure 4.9, showing a snapshot in time before and at water breakthrough at the production well, respectively. The solid line represents the production well P-6. b) and d) Predicted EK, ED and SP along the well before and at water breakthrough, respectively.

7.4 Conclusions

Our results do not encourage SP monitoring for tracking waterfronts in the BGSU reservoir. SP signals above an assumed noise level could not be obtained before or at the water breakthrough at the production well. The low signals were found to be mainly due to the very high reservoir permeability up to 10 Darcy in the sweet spots. Despite the low magnitude of the predicted SP signals, SP anomalies occurred and were represented by the skewness of the SP vertical profile at the production well towards the fastest waterfront with the earliest breakthrough. Similar anomalies could not be detected for later approaching fronts prior to breakthrough owing to the high SP arising in the fastest front. These results emphasize the importance of understanding reservoir geology to better interpret SP signals and to select candidate reservoirs for the deployment of the technology.

Calibrating the results based on the experimental measurements of EK and ED coupling coefficients and rock conductivity resulted in approximately ten times lower signals. This highlights the importance of the experimental work to obtain representative and reliable electrical properties. Considering the noise level of 0.1 mV suggested by Chen et al. (2006) and used in previous studies (e.g., Saunders et al., 2008; Gulamali et al., 2011; Jackson et al., 2012b; Ijioma, 2016), our results suggested that no reliable signals can be detected before water breakthrough. However, if we consider a lower noise level, which potentially can be achieved by better tool design, then, the predicted signals can be considered reliable and useful for waterfront monitoring.

Chapter 8

Summary, Conclusions and Future Work

8.1 Summary and Conclusions

Monitoring water production in hydrocarbon reservoirs is one of the key elements of reservoir management; however, it is very a challenging task for petroleum engineers. Serious consequences are associated with the presence of water in the production wells, which can manifest in reducing the effective hydrocarbon permeability in the wellbore vicinity and cause well integrity, flow assurance and surface water handling issues. Today, there are a few methods available for the early detection of water encroachment using seismic, electromagnetic and resistivity measurements. However, these methods are limited either by the depth of investigation which only covers the near wellbore area or low spatial and temporal resolutions. Recent work in the field of petroleum geoscience suggests that SP signals could be used to predict the arrival of water in production wells while it is tens to hundreds of metres away. Therefore, SP monitoring could have a profound application in remotely detecting approaching waterfronts in hydrocarbon reservoirs, given the low cost and the simple implementation procedures.

Despite the large potential of this new monitoring technique, it has not yet been tested on actual hydrocarbon reservoirs. To date, most of the research conducted was based on synthetic reservoir models. Therefore, in this work we aim to extend the reach of this technique to an oil reservoir in Kuwait. We investigated, for the first time, the feasibility of the SP monitoring on Greater Burgan reservoir, which is considered to be the largest sandstone reservoir in the world. This study evaluates the technology and identifies possible operational and economic benefits.

We started by developing an SP modelling tool (SP solver) to numerically simulate self-potential (SP) in subsurface reservoirs, using values of water saturation, pressure, concentration and temperature from existing reservoir flow and transport simulators. The code differs from its earlier versions through its ability to model faults in multiple directions and model different polarity affects. The validity of the SP solver was proved through a series of single and multiphase flow test cases.

Then, we selected the Burgan upper sand (BGSU) layer as the target reservoir layer to conduct our study. After that, we prepared the dynamic model in ECLIPSE to simulate different production scenarios to be used in SP modelling. We then collected rock samples covering the six different rock types encountered in the field to experimentally characterise the EK and ED coupling coefficients.

In the EK experiments, the EK coupling coefficient and zeta potential were measured on four sandstone plugs from BGSU at two saturation states: (i) fully saturated with high concentration FMB rich in divalent ions; and (ii) at residual oil saturation. Two of the sandstone samples were quartz-dominated while the other two were rich in dolomite and siderite. In fully saturated measurements, the quartz-dominated samples resulted in small but negative values of the EK coupling coefficient and zeta potential, consistent with previous studies on quartz-dominated sandstones. The other two samples, that were rich in dolomite and siderite, resulted in positive values of the EK coupling coefficient and zeta potential which have not been observed before. This was attributed to the positively charged surface of dolomite and siderite which formed a significant portion of the pore space, in addition to the effects of ion adsorption onto quartz mineral surfaces and ion exchange with clay minerals. At the residual oil saturation, the measured parameters exhibited different behaviour, compared to the fully saturated condition, which does not match with the assumption, of the EK coupling coefficient at full saturation and residual oil saturation being the same, used in most of the previous modelling studies. Three of the four samples exhibited a polarity change in the measured EK coupling coefficient and zeta potential when changing between the two saturation states. The direction of the polarity change, whether positive to negative or vice versa, was dependent on the sample, where two samples showed a positive change in the parameters and the third sample showed a negative change. The direction of change in the magnitude and polarity of the measured coupling coefficient and zeta potential between full saturation and residual oil saturation is indicative of the polarity of the oil-brine interface; a positive change indicates a positive interface and vice versa. Since the same oil, brine and experimental conditions were considered in these experiments, this change in the polarity of oil-brine interface was suggested to be dependent on the rock itself and the interaction between rock, brine and oil.

In the ED experiments, the ED potential was measured on four sandstone samples and five shale samples covering the six rock types encountered in BGSU. The ED potential was measured across the samples with a concentration gradient between the FMB and seawater, mimicking the water flooding approach used on similar reservoirs in Kuwait. The measurements were performed when the samples were fully saturated with FMB and at conditions of partial saturation (saturation end points: residual oil saturation and irreducible water saturation) with crude oil and FMB. At full saturation and residual oil saturation, the ED potential was dominated by the diffusion potential, with the shale samples slightly more exclusive which is consistent with the previous studies. We also observed a trend of increasing contribution of the exclusion potential with decreasing permeability due to the electrical charge on the mineral surface that occupies larger volume in smaller pores. The consistency of the results at full saturation and residual oil saturation is because most of the pores are filled with water. On the other hand, the ED potential was more exclusive at the irreducible water saturation, and the polarity of the excluded ions was dependent on the polarity of charged oil-brine interface. The oil-brine interfacial charge was interpreted to be positive in three of the four samples, despite literature data suggesting that it is typically negative. Moreover, Samples with lower irreducible water saturation were found to be more exclusive due to the confinement of the excess charge (ions) within smaller, water-occupied pores from which co-charges are efficiently excluded.

Finally, we simulated the SP in BGSU considering multiple production scenarios, testing the effects of flow rate, well spacing, brine salinity, shale conductivity, rock permeability and well completion. The modelling results were not promising with respect to field implantation in BGSU due to: (i) low magnitude of the simulated SP signals due to the very high reservoir permeability in the clean sand channels through which most of the flow occurs; and (ii) inability to locate SP anomalies in multi-layered reservoirs after the breakthrough of the fastest front; the high SP arising in the fastest front dissipates in the high conductivity bounding shale layers masking the SP signal in other approaching fronts. These results emphasize the significance of understanding the reservoir geology to better interpret SP signals and the importance of careful selection of candidate reservoirs for the deployment of this technology. Throughout this study, the predicted SP signals at the monitored wells were

compared against an assumed noise level of 0.1 mV, and they were found much lower than the noise level (> ten times lower). However, the technology may have monitoring benefits if a lower noise level can be achieved through an improved tool design and installation procedures.

8.2 Implications

Our results have broad implications for a number of applications including the implementation of SP monitoring in hydrocarbon reservoirs, geophysical monitoring, rock-brine chemical interactions and the electrokinetic and exclusion-diffusion potentials of natural sandstones in the subsurface:

- The code developed serves the field of geophysical monitoring as it can be used to predict the SP in a broad range of subsurface reservoir types including aquifers, geothermal reservoirs, targets for CO₂ storage, and hydrocarbon reservoirs.
- Many natural sandstones contain calcite, dolomite, siderite and other minerals that may have positively charged surfaces in natural brines rich in divalent ions. Our electrokinetic potential experiments results show that it can be erroneous to assume that sandstones are negatively charged, or that experimentally-determined zeta potential trends obtained in quartz-dominated samples saturated with simple NaCl brines are applicable in the subsurface.
- Electrokinetic potential measurements at residual oil saturations show that the EK coupling coefficient may be different than the one measure at full saturation in terms of both magnitude and polarity. Therefore, it is important to be experimentally determined as assuming it to be the same as the one measured at full saturation may be invalid.
- Our exclusion-diffusion potential experiments showed that the contribution of the exclusion potential is very low at high salinity environments. Therefore, it is acceptable to assume the domination of the diffusion potential in such conditions.
- The two phase exclusion-diffusion potential experiments highlight the importance of understanding the oil-brine interface, and the effect it plays in determining the ion exclusion process. Therefore,

it is unacceptable to assume neither that the negative ions will always be excluded nor the exclusion-diffusion potential is exclusion dominated at low water saturation as concluded and used by previous studies.

- Although our feasibility assessment in BGSU did not encourage proceeding to field trials, it helped developing an understanding of the SP behaviour in high salinity complex environments. It also helped setting the rules for selecting the next candidate which should be more homogenous (than BGSU) and have lower permeability and salinity (although most hydrocarbon reservoirs have comparable salinity to the one in BGSU). We generated general curves that can aid in the candidate selection process (Figure 8.1) which was based on the reservoir model of Jackson et al. (2012).
- The feasibility assessment emphasizes the importance of experimentally-measured coupling coefficients as this may reveal new patterns that may not be predicted based on literature data performed on clean sandstone samples saturated with simple brines.

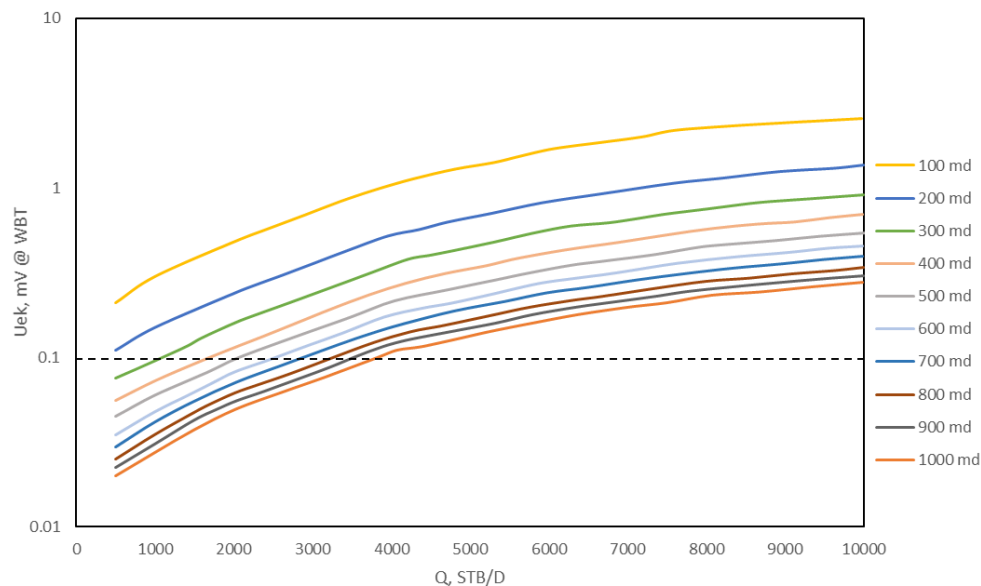


Figure 8.1: EK potential at a monitoring well at the time of water breakthrough versus flow rates for Range of reservoir permeability. The dashed line represents the assumed noise level of 0.1 mV.

8.3 Future Work

- Incorporating the SP algorithm established in chapter 3 into existing open-source codes for fluid flow and transport.
- Running extra validation tests on the SP solver by testing its predictions against previously published studies.
- Potential additional experimental work on the BGSU core plugs involves
 - Repeating the EK experiments to eliminate any doubt of experimental artefacts that might have affected the results, especially the observations on sample SS1 at residual oil saturation.
 - Testing the effect of temperature on the measured EK and ED coupling coefficients.
 - Testing the effect of gradually increasing the concentration of divalent ions such as Ca^{+2} , Mg^{+2} and SO_4^{-2} .
 - Characterising the wettability of the four sandstone samples, which may help in interpreting the polarity change in the zeta potential among the samples.
 - Running X-ray diffraction to obtain the exact mineralogy of the samples to confirm our hypothesis on the positive zeta potential at full saturation.
- In Chapter 5, two sandstone samples displayed a positive EK coupling coefficient and zeta potential which has not been observed previously, and was interpreted to be caused by the presence of dolomite and siderite mineral surfaces which are positively charged in the presence of high concentrations of divalent ions, in addition to the adsorption of divalent ions onto quartz mineral surfaces and ion exchange with clay minerals. However, as positive coupling coefficient and zeta potential were not reported before for sandstones, additional work is required to confirm this interpretation. Potential future work to confirm this interpretation is to investigate the coupling coefficients and zeta potentials on artificial samples made of various combinations of quartz, dolomite and siderite.

- During the investigation of the EK coupling coefficient and zeta potential on the sandstone samples at residual oil saturation in Chapter 5, the interpreted polarity of the oil-brine interface was found to vary among the four investigated samples although the same oil, brine and experimental conditions were used. This was suggested to be related to the rock itself and the interaction between rock, brine and oil. However more work is required to understand this relation.
- There was no attempt to investigate the EK potential at irreducible water saturation, and it was assumed that the EK coupling coefficient is zero at irreducible water saturation following the approach of Jackson et al. (2012), although Vinogradov and Jackson (2011) observed a non-zero coupling coefficient. Hence, more work is required following the procedures of Vinogradov and Jackson (2011) to investigate the EK potential at irreducible water saturation.
- In chapter 6, the ED potential at irreducible water saturation was investigated in our sandstone samples and found to be slightly exclusive, and that the type of the excluded ions was dependent on the polarity of the oil-brine interface (i.e., positively charged interface leads to positive ions' exclusion and vice versa). However, this interpretation was based on the results of this study only as no previous study addressed this phenomenon. Therefore, suggested future work may include the characterisation of the ED potential at low water saturation and its relation with the ion exclusion.
- The EK and ED experiments conducted in this study were performed at full saturation, residual oil saturation and irreducible water saturation. There was not attempt to experimentally investigate the behaviour at partial saturations ($S_{wirr} < S_w < 1 - S_{or}$), and the model of Jackson was used to model the saturation dependence of the coupling coefficient. Thus, a better understanding of the coupling coefficients during multiphase flow experiments is highly important.
- With regard to the field trials, the same workflow can be followed to assess the SP monitoring in other fields comprising different reservoir, geological and production conditions in order to develop a better understanding of SP behaviour.

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Appendix A

Final equations in 3D form

In this section, we present the expanded form of equation (3.9) over a 3D domain as follow

$$\begin{aligned}
 & a_{\bar{x}_{i+1}} U_{i+1,j,k} + a_{\bar{y}_{j+1}} U_{i,j+1,k} + a_{\bar{z}_{k+1}} U_{i,j,k+1} + a_p U_{i,j,k} + a_{\bar{x}_{i-1}} U_{i-1,j,k} + a_{\bar{y}_{j-1}} U_{i,j-1,k} \\
 & + a_{\bar{z}_{k-1}} U_{i,j,k-1} \\
 & = b_{\bar{x}_{i+1}} \Phi_{i+1,j,k} + b_{\bar{y}_{j+1}} \Phi_{i,j+1,k} + b_{\bar{z}_{k+1}} \Phi_{i,j,k+1} + b_p \Phi_{i,j,k} + b_{\bar{x}_{i-1}} \Phi_{i-1,j,k} \\
 & + b_{\bar{y}_{j-1}} \Phi_{i,j-1,k} + b_{\bar{z}_{k-1}} \Phi_{i,j,k-1}
 \end{aligned} \tag{A.1}$$

where

$$a_{\bar{x}_{i+1}} = \frac{\sigma_{fs\bar{x}_{i+1}}}{x_{i+1} - x_i} \tag{A.2 a),} \quad a_{\bar{x}_{i-1}} = \frac{\sigma_{fs\bar{x}_i}}{x_i - x_{i-1}} \tag{A.2 b)}$$

$$a_{\bar{y}_{j+1}} = \frac{\sigma_{fs\bar{y}_{j+1}}}{y_{j+1} - y_j} \tag{A.2c),} \quad a_{\bar{y}_{j-1}} = \frac{\sigma_{fs\bar{y}_j}}{y_j - y_{j-1}} \tag{A.2 d)}$$

$$a_{\bar{z}_{k+1}} = \frac{\sigma_{fs\bar{z}_{k+1}}}{z_{k+1} - z_k} \tag{A.2 e),} \quad a_{\bar{z}_{k-1}} = \frac{\sigma_{fs\bar{z}_k}}{z_k - z_{k-1}} \tag{A.2 f)}$$

$$a_p = - \left(a_{\bar{x}_{i+1}} + a_{\bar{x}_{i-1}} + a_{\bar{y}_{j+1}} + a_{\bar{y}_{j-1}} + a_{\bar{z}_{k+1}} + a_{\bar{z}_{k-1}} \right) \tag{A.2 c)}$$

$$b_{\bar{x}_{i+1}} = - \frac{L_{EK\bar{x}_{i+1}}}{x_{i+1} - x_i} \tag{A.2 j),} \quad b_{\bar{x}_{i-1}} = - \frac{L_{EK\bar{x}_i}}{x_i - x_{i-1}} \tag{A.2 h)}$$

$$b_{\bar{y}_{j+1}} = - \frac{L_{EK\bar{y}_{j+1}}}{y_{j+1} - y_j} \tag{A.2 i),} \quad b_{\bar{y}_{j-1}} = - \frac{L_{EK\bar{y}_j}}{y_j - y_{j-1}} \tag{A.2 j)}$$

$$b_{\bar{z}_{k+1}} = - \frac{L_{EK\bar{z}_{k+1}}}{z_{k+1} - z_k} \tag{A.2 k),} \quad b_{\bar{z}_{k-1}} = - \frac{L_{EK\bar{z}_k}}{z_k - z_{k-1}} \tag{A.2 l)}$$

$$b_p = - \left(b_{\bar{x}_{i+1}} + b_{\bar{x}_{i-1}} + b_{\bar{y}_{j+1}} + b_{\bar{y}_{j-1}} + b_{\bar{z}_{k+1}} + b_{\bar{z}_{k-1}} \right) \tag{A.2 m)}$$

The formulation considered in this study assumes that the current flow occurs in the i, j and k directions along the x, y, and z directions, respectively. Diagonal flow of electrical current across xy, xz and yz directions is ignored.

Interface properties

The procedures used to derive the formulas for the saturated rock conductivity and coupling terms at the interface between two grid cells are presented here. We consider only the electrokinetic potential (EK) and show the derivation along the x direction only. The same steps were followed to derive the formulas for the electrochemical and thermoelectrical potentials. Referring to Figure 3.2, the total current at the interface is continuous.

$$I_{\bar{x}_{i+1}} = -\sigma_{fs_{\bar{x}_{i+1}}} \nabla U_{\bar{x}_{i+1}} - L_{EK_{\bar{x}_{i+1}}} \nabla \Phi_{\bar{x}_{i+1}} \quad (A.3)$$

$\nabla U_{\bar{x}_{i+1}}$ can be approximated as

$$\nabla U_{\bar{x}_{i+1}} = \frac{U_{x_{i+1}} - U_{x_i}}{x_{i+1} - x_i} = \frac{(U_{x_{i+1}} - U_{\bar{x}_{i+1}}) + (U_{\bar{x}_{i+1}} - U_{x_i})}{x_{i+1} - x_i} = \frac{(U_{x_{i+1}} - U_{\bar{x}_{i+1}})}{x_{i+1} - x_i} + \frac{(U_{\bar{x}_{i+1}} - U_{x_i})}{x_{i+1} - x_i} \quad (A.4)$$

Knowing that

$$\frac{x_{i+1} - x_i}{x_{i+1} - x_i} = \frac{x_{i+1} - \bar{x}_{i+1}}{x_{i+1} - x_i} + \frac{\bar{x}_{i+1} - x_i}{x_{i+1} - x_i} = m + n = 1 \quad (A.5)$$

then $x_{i+1} - x_i$ can be written as

$$x_{i+1} - x_i = \frac{x_{i+1} - \bar{x}_{i+1}}{m} = \frac{\bar{x}_{i+1} - x_i}{n} \quad (A.6)$$

Substituting equation (A6) in equation (A4)

$$\nabla U_{\bar{x}_{i+1}} = m \nabla U_{x_{i+1}} + n \nabla U_{x_i} \quad (A.7)$$

Now, we apply equation (A3) for cells i and $i + 1$ as follows

$$I_{x_i} = -\sigma_{fs_{x_i}} \nabla U_{x_i} - L_{EK_{x_i}} \nabla \Phi_{x_i} \quad (A.8)$$

$$I_{x_{i+1}} = -\sigma_{fs_{x_{i+1}}} \nabla U_{x_{i+1}} - L_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}} \quad (A.9)$$

Next, we rearrange equations (A8) and (A9) for ∇U_{x_i} & $\nabla U_{x_{i+1}}$

$$\nabla U_{x_i} = -\frac{I_{x_i}}{\sigma_{fs_{x_i}}} - \frac{L_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} \quad (A.10)$$

$$\nabla U_{x_{i+1}} = -\frac{I_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} - \frac{L_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} \quad (A.11)$$

After that, we substitute equation (A10) and equation (A11) in equation (A7)

$$\nabla U_{\bar{x}_{i+1}} = m \left(-\frac{I_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} - \frac{L_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} \right) + n \left(-\frac{I_{x_i}}{\sigma_{fs_{x_i}}} - \frac{L_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} \right) \quad (A.12)$$

Rearranging equation (A12) results in

$$\nabla U_{\bar{x}_{i+1}} = - \left(\frac{nI_{x_i}}{\sigma_{fs_{x_i}}} + \frac{mI_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} \right) - \left(\frac{nL_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} + \frac{mL_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} \right) \quad (A.13)$$

Assuming the total current is continuous ($I_{x_i} = I_{x_{i+1}} = I_{\bar{x}_{i+1}}$), we can write equation (A13) as

$$\nabla U_{\bar{x}_{i+1}} = -I_{\bar{x}_{i+1}} \left(\frac{n}{\sigma_{fs_{x_i}}} + \frac{m}{\sigma_{fs_{x_{i+1}}}} \right) - \left(\frac{nL_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} + \frac{mL_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}} \right) \quad (A.14)$$

$I_{\bar{x}_{i+1}}$ can be calculated by arranging equation (A14) as follows

$$I_{\bar{x}_{i+1}} = - \frac{\nabla U_{\bar{x}_{i+1}}}{\frac{n}{\sigma_{fs_{x_i}}} + \frac{m}{\sigma_{fs_{x_{i+1}}}}} - \frac{\frac{nL_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} + \frac{mL_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}}}{\frac{n}{\sigma_{fs_{x_i}}} + \frac{m}{\sigma_{fs_{x_{i+1}}}}} \quad (A.15)$$

The first component of equation A15 is the conduction current related to the naturally occurring SP (∇U), while the second component is the streaming current related to the pressure gradient ($\nabla \Phi$).

The saturated rock conductivity ($\sigma_{fs_{\bar{x}_{i+1}}}$) at the interface between grid cells i and $i + 1$ can be calculated by equating the first term of equation (A3) and (A15) as follows

$$\sigma_{fs_{\bar{x}_{i+1}}} = \frac{1}{\frac{n}{\sigma_{fs_{x_i}}} + \frac{m}{\sigma_{fs_{x_{i+1}}}}} = \frac{\sigma_{fs_{x_i}} \sigma_{fs_{x_{i+1}}} (x_{i+1} - x_i)}{(x_{i+1} - \bar{x}_{i+1}) \sigma_{fs_{x_i}} + (\bar{x}_{i+1} - x_i) \sigma_{fs_{x_{i+1}}}} \quad (A.16)$$

For the coupling term at the interface ($L_{EK_{\bar{x}_{i+1}}}$), we need to equate the second terms of equations (A3) and (A15) as

$$L_{EK_{\bar{x}_{i+1}}} \nabla \Phi_{\bar{x}_{i+1}} = \frac{\frac{nL_{EK_{x_i}} \nabla \Phi_{x_i}}{\sigma_{fs_{x_i}}} + \frac{mL_{EK_{x_{i+1}}} \nabla \Phi_{x_{i+1}}}{\sigma_{fs_{x_{i+1}}}}}{\frac{n}{\sigma_{fs_{x_i}}} + \frac{m}{\sigma_{fs_{x_{i+1}}}}} \quad (A.17)$$

Rearranging equation (A17) considering the numerical approximation of $\nabla \Phi_{x_i}$, $\nabla \Phi_{x_{i+1}}$, and $\nabla \Phi_{\bar{x}_{i+1}}$, and considering the definition of m and n for equation A5, equation (A17) can be written as

$$L_{EK_{\bar{x}_{i+1}}} (\Phi_{x_{i+1}} - \Phi_{x_i}) = \frac{\sigma_{fs_{x_{i+1}}} L_{EK_{x_i}} (\Phi_{\bar{x}_{i+1}} - \Phi_{x_i}) + \sigma_{fs_{x_i}} L_{EK_{x_{i+1}}} (\Phi_{x_{i+1}} - \Phi_{\bar{x}_{i+1}})}{m\sigma_{fs_{x_i}} + n\sigma_{fs_{x_{i+1}}}} \quad (A.18)$$

The only unknown value in equation (A18) is $\Phi_{\bar{x}_{i+1}}$, which is the water potential at the interface between cells i and $i + 1$. This value can be approximated by linear interpolation. The final formula of $L_{EK_{\bar{x}_{i+1}}}$ can be written as

$$L_{EK_{\bar{x}_{i+1}}} = \frac{\sigma_{fs_{x_{i+1}}} L_{EK_{x_i}} (\bar{x}_{i+1} - x_i) + \sigma_{fs_{x_i}} L_{EK_{x_{i+1}}} (x_{i+1} - \bar{x}_{i+1})}{(x_{i+1} - \bar{x}_{i+1}) \sigma_{fs_{x_i}} + (\bar{x}_{i+1} - x_i) \sigma_{fs_{x_{i+1}}}} \quad (A.19)$$

which is the same as equation (3.14) presented in the main text. The same derivation can be applied to obtain the interface properties along the y and z directions. The final formulas are shown below

$$\sigma_{fs_{\bar{y}_{j+1}}} = \frac{\sigma_{fs_{y_j}} \sigma_{fs_{y_{j+1}}} (y_{j+1} - y_j)}{(y_{j+1} - \bar{y}_{j+1}) \sigma_{fs_{y_j}} + (\bar{y}_{j+1} - y_j) \sigma_{fs_{y_{j+1}}}} \quad (A.20)$$

$$L_{EK_{\bar{y}_{j+1}}} = \frac{\sigma_{fs_{y_{j+1}}} L_{EK_{y_j}} (\bar{y}_{j+1} - y_j) + \sigma_{fs_{y_j}} L_{EK_{y_{j+1}}} (y_{j+1} - \bar{y}_{j+1})}{(y_{j+1} - \bar{y}_{j+1}) \sigma_{fs_{y_j}} + (\bar{y}_{j+1} - y_j) \sigma_{fs_{y_{j+1}}}} \quad (A.21)$$

$$\sigma_{fs_{\bar{z}_{k+1}}} = \frac{\sigma_{fs_{z_k}} \sigma_{fs_{z_{k+1}}} (z_{k+1} - z_k)}{(z_{k+1} - \bar{z}_{k+1}) \sigma_{fs_{z_k}} + (\bar{z}_{k+1} - z_k) \sigma_{fs_{z_{k+1}}}} \quad (A.22)$$

$$L_{EK_{\bar{z}_{k+1}}} = \frac{\sigma_{fs_{z_{k+1}}} L_{EK_{z_k}} (\bar{z}_{k+1} - z_k) + \sigma_{fs_{z_k}} L_{EK_{z_{k+1}}} (z_{k+1} - \bar{z}_{k+1})}{(z_{k+1} - \bar{z}_{k+1}) \sigma_{fs_{z_k}} + (\bar{z}_{k+1} - z_k) \sigma_{fs_{z_{k+1}}}} \quad (A.23)$$

Appendix B

Brine Viscosity and Brine permittivity calculations

Brine Viscosity

The brine viscosity (μ) was described as a function of temperature (T, C^o) and concentration (C_f , M/L) by Kestin et al. (1978) as follows

$$\mu(T, C_f) = \mu(T, 0) \times \mu_r(T, C_f) \quad (B.1)$$

Where

$$\log \left(\frac{\mu(T, 0)}{\mu(20, 0)} \right) = \frac{1}{(T + 96)} [(20 - T)(1.2378 - 1.303 \times 10^{-3} \times (20 - T) + 3.06 \times 10^{-6} \times (20 - T)^2 + 2.55 \times 10^{-8} \times (20 - T)^3)] \quad (B.2)$$

and

$$\mu(20, 0) = 0.001002 \quad (B.3)$$

The relative viscosity (μ_r) as function of concentration and temperature is given by

$$\log_{10} (\mu_r(T, C_f)) = A(C_f) + B(C_f) \log \left(\frac{\mu(T, 0)}{\mu(20, 0)} \right) \quad (B.4)$$

where

$$A(C_f) = 3.3324 \times 10^{-2} C_f + 3.624 \times 10^{-3} C_f^2 - 1.879 \times 10^{-4} C_f^3 \quad (B.5)$$

$$B(C_f) = -3.96 \times 10^{-2} C_f + 1.02 \times 10^{-2} C_f^2 - 7.02 \times 10^{-4} C_f^3 \quad (B.6)$$

Brine permittivity

The brine permittivity can be defined as function of temperature (T, C°) and salinity (C_f , *part per thousand*) as follows (Stogryn, 1971)

$$\varepsilon_r(T, N) = \varepsilon_r(T, 0)a(N) \quad \text{B.7}$$

$$\varepsilon_r(T, 0) = 87.74 - 0.40008T + 9.398 \times 10^{-4}T^2 + 1.41 \times 10^{-6}T^3 \quad \text{B.8}$$

$$a(N) = 1 - 0.2551N + 5.151 \times 10^{-2}N^2 - 6.889 \times 10^{-3}N^3 \quad \text{B.9}$$

Where N is the normality of the brine and is related to the concentration through

$$N = 1.707 \times 10^{-2}C_f + 1.205 \times 10^{-5}C_f^2 + 4.058 \times 10^{-9}C_f^3 \quad \text{B.10}$$

Then, the brine permittivity is given by

$$\varepsilon = \varepsilon_r \varepsilon_0 \quad \text{B.11}$$

Where ε_0 is the vacuum permittivity ($8.85 \times 10^{-12} \text{ F/m}$).

Appendix C

Theoretical descriptions of the pure diffusion and pure exclusion end-members have been provided previously (Sen, 1989; Revil, 1999, Leinov and Jackson, 2014), and we present only a succinct summary here. In porous media where diffusion dominates, ion transport (including multiple, multi-valent ionic species) can be described in terms of chemical diffusion and electromigration in the absence of other thermodynamic driving forces according to the Nernst-Planck equation (Lanteri et al., 2009)

$$j_i = -K_i D_i \left(\nabla c_i + \frac{F z_i}{RT} c_i \nabla V_D \right) \quad (\text{C.1})$$

where subscript i refers to a specific ionic species, j_i is the ion molar flux, K_i is the hindrance diffusion coefficient, D_i is the diffusion coefficient, c_i is the concentration, z_i is the charge number, F is the Faraday constant, R is the ideal gas constant, T is the absolute temperature and V_D is the diffusion potential. Assuming that the length of the porous medium (connected pore-space) is much larger than the pore throat radius, equation (C.1) can be expressed in one dimension as (Lanteri et al., 2009)

$$j_i = -K_i D_i \left(\frac{dc_i}{dx} + \frac{F z_i}{RT} c_i \frac{dV_D}{dx} \right) \quad (\text{C.2})$$

Equation (C.2) can be coupled with the electroneutrality condition (Lanteri et al., 2009)

$$\sum F z_i j_i = 0 \quad (\text{C.3})$$

Substituting equation (C.2) in equation (C.3) and introducing $R = k_B N$ and $F = eN$, where k_B is the Boltzmann constant, e is the electron charge and N is Avogadro's number, yields

$$\frac{dV_D}{dx} = -\frac{k_B T}{e} \left(\frac{\sum K_i D_i z_i \frac{dc_i}{dx}}{\sum K_i D_i z_i^2 c_i} \right) \quad (\text{C.4})$$

Assuming constant concentration gradient and integrating equation (C.4) over the length of the porous medium of interest yields an expression for the diffusion dominated electrical potential that arises in response to a concentration difference $C_i^L - C_i^0$ across a porous medium (Figure C.1)

$$\Delta V_D = -\frac{k_B T}{e} \left(\frac{\sum_i K_i D_i z_i (C_i^L - C_i^0)}{\sum_i K_i D_i z_i^2 (C_i^L - C_i^0)} \right) \ln \left(\frac{\sum_i K_i D_i z_i^2 C_i^0}{\sum_i K_i D_i z_i^2 C_i^L} \right) \quad (\text{C.5})$$

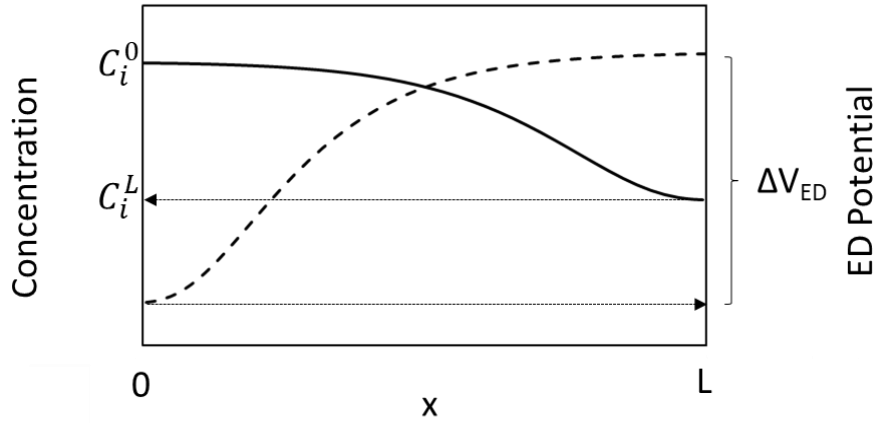


Figure C.1: An example of a 1-D system showing the variation of concentration and ED potential along the length of a porous media (from 0 to L).

When exclusion dominates, only counter-ions with opposing polarity to the electrical charge on the mineral surfaces are allowed to enter the pore space; co-ions are excluded. Therefore, to obtain the exclusion potential, the same derivation shown in equations (C.1) through (C.5) is applied to the counter-ions only. For example, in a negatively charged porous media saturated with 1:1 brine (e.g. NaCl), the negative ions are excluded from the pore space. Equation (C.5) becomes

$$\Delta V_E = -\frac{k_B T}{e} \left(\frac{K_+ D_+ z_+ (C_+^L - C_+^0)}{K_+ D_+ z_+^2 (C_+^L - C_+^0)} \right) \ln \left(\frac{K_+ D_+ z_+^2 C_+^0}{K_+ D_+ z_+^2 C_+^L} \right) \quad (C.6)$$

where subscript + refers to positive ions (Na^+ in case of NaCl brine) and V_E is the exclusion potential. Substituting the charge number of Na^+ ($z_+ = +1$) and simplifying leads to

$$\Delta V_E = -\frac{k_B T}{e} \ln \left(\frac{C_+^0}{C_+^L} \right) \quad (C.7)$$

which is equivalent to the expression for 1:1 brine presented as equation (14) in Leinov and Jackson (2014).

The parameters used in equation (C.5) to calculate the diffusion potential are presented in Table C.1. The diffusion coefficients (D_i) for each ion are from Haynes and Lide (2012). The hindrance diffusion coefficients (K_i) are calculated using the approach presented in Lanteri et al. (2009)

$$K_i = \frac{6\pi}{K_{i,t}} \quad (C.8)$$

$$K_{i,t} = \frac{9}{4} \pi^2 \sqrt{2} (1 - \lambda_i)^{-5/2} \left[1 + \sum_{n=1}^2 a_n (1 - \lambda_i)^n \right] + \sum_{n=0}^4 a_{n+3} \lambda_i^n \quad (C.9)$$

$$\lambda_i = \frac{r_i}{r_p} \quad (C.10)$$

where r_i is the stokes radius of ion i and r_p the pore radius. The pore radii used for the investigated rock samples are 10^{-5} m and 10^{-8} m for the sandstone and shale samples, respectively ((Al-Jallad et al., 2017). Coefficients a_1 to a_7 are given as -73/60, 77.293/50.400, -22.5083, -5.6117, -0.3363, -1.216, and 1.647, respectively. The stokes radius can be calculated as follows

$$r_i = \frac{k_B T}{6\pi\mu D_i} \quad (C.11)$$

where k_B is the Boltzmann constant, D_i is the diffusion coefficient of ion (i), T is the absolute temperature and μ is the fluid dynamic viscosity.

Table C.1: Parameters used in the equation (C.5) to calculate the doffusion-dominated potential.

$k_B, \text{m}^2\text{kg s}^{-2}\text{K}^{-1}$	1.38065×10^{-23}			
T, K°	295.65			
e, C	1.60218×10^{-19}			
Salt	$D_i, \text{m}^2/\text{s}$	z_i	K_i (Sandstones)	K_i (Shale)
Na ⁺	1.334×10^{-9}	+1	0.995147	0.996471
Cl ⁻	$2.032E \times 10^{-9}$	-1	0.995097	0.995965
K ⁺	1.957×10^{-9}	+1	0.995186	0.996002
Mg ⁺²	7.06×10^{-10}	+2	0.995278	0.997782
Ca ⁺²	7.92×10^{-10}	+2	0.995248	0.997483
Br ⁻	$2.08E \times 10^{-9}$	-1	0.995095	0.995943
SO ₄ ⁻²	1.065×10^{-9}	-2	0.995184	0.996843
HCO ₃ ⁻¹	1.185×10^{-9}	-1	0.995166	0.996656