The Effect of Clay, Pressure and Temperature on the Electrical and Hydraulic Properties of Real and Synthetic Rocks

by

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ABSTRACT

This thesis presents the methods and results of a systematic study of the effect of clay, pressure and temperature on the electrical and hydraulic properties of natural and synthetic rocks. A better understanding of the mechanisms of the effect of pressure and temperature on rock petrophysical characteristics has been achieved in this study. An improved shaley sand interpretation technique based on the experimental data and the numerical simulation results has been developed.

A novel multi-sample high pressure and high temperature rock testing system connected to an automatic data acquisition unit has been developed to measure the electrical and hydraulic properties of 5 core plugs of 1.5” in diameter simultaneously. The use of this novel experimental system increases the speed of testing and, since all the samples are placed in identical conditions, eliminates experimental comparison errors caused by the fluctuations of pressure and temperature.

A new technique of making synthetic shaley rock samples with desired clay type, content and distribution mode has been developed in order to study systematically the effect of clay minerals on the electrical properties of shaley sands at both room and reservoir conditions. The synthetic shaley samples made are tested in the multi-sample high pressure and high temperature experimental rig.

Two 3D pore space network models (NETSIM and CLAY) have been developed to interpret and predict the effect of pressure, temperature and clay on the electrical and hydraulic properties of porous rocks. NETSIM relates the electrical resistivity and permeability of porous rocks to their microscopic pore structures and, therefore, provides an insight into the mechanisms of the effect of pressure and temperature. CLAY simulates the effect of clay content and clay distribution on shaley sand conductivities, and provides a means for quantifying the clay distribution coefficient defined in this study.

Significant effect of pressure and temperature on both the electrical resistivity
and the absolute permeability of sandstone rocks has been observed. This effect is more pronounced for less porous and permeable rocks compared with more porous and permeable rocks. The combined effect of pressure and temperature on the electrical properties of sandstone rocks is found to be approximately the sum of their individual effect. In addition to the actual effect of pressure and temperature, a significant hysteresis effect has been observed in both pressure and temperature tests. In order to ensure the accuracy of the estimation of in situ rock porosity and hydrocarbon saturation from electrical logs, the Archie cementation factor and saturation exponent need to be quantified in the laboratory at simulated reservoir conditions accounting for the effect of coupled pressure and temperature and the hysteresis.

An improved Waxman-Smits model is proposed by including a temperature coefficient \((\omega)\) for the equivalent clay counterion conductivity, which is a function of temperature and clay content, and a clay distribution coefficient \((\tau)\) for the clay content \((Q_v)\). The values for \(\omega\) as a function of temperature and clay content have been determined experimentally. The clay distribution coefficient \((\tau)\) as a function of clay distribution modes has been quantified for identified clay distributions based on the numerical model (CLAY). The use of this modified W-S model enables an improvement in the accuracy of the estimation of in situ porosity and hydrocarbon saturation of shaley formations.
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<td>empirical constant</td>
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<td>empirical constant relating to clay content</td>
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<tr>
<td>B'</td>
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<td>empirical constant</td>
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<td>b'</td>
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<td>half width of elliptic or tapered cross-section</td>
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<td>empirical constant</td>
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<td>shaley solid conductivity</td>
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<td>mho/m or mho/cm</td>
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<td>mho/m</td>
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<td>mho/m</td>
<td>equivalent clay counterion conductivity</td>
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<tr>
<td>DOD</td>
<td></td>
<td>degree of dispersion of clay</td>
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<td>DOL</td>
<td></td>
<td>degree of lamination of clay</td>
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<tr>
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<td>formation factor</td>
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<td>formation factor at $R_w = 0.01\ ohm \cdot m$</td>
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<td>$F_T^*$</td>
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<td>shaley sand formation factor</td>
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<tr>
<td>I</td>
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<td>$i, j, k$</td>
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<tr>
<td>k</td>
<td>$mD$</td>
<td>permeability</td>
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<td>$mD$</td>
<td>liquid phase permeability</td>
</tr>
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<td>$k_{oo}$</td>
<td>$mD$</td>
<td>Klinkenber corrected permeability</td>
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<td>$k_o$</td>
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<td>pore shape factor</td>
</tr>
<tr>
<td>Symbol</td>
<td>Unit</td>
<td>Description</td>
</tr>
<tr>
<td>--------</td>
<td>------</td>
<td>-------------</td>
</tr>
<tr>
<td>$L, L_0, l$</td>
<td>$m$ or $cm$</td>
<td>length</td>
</tr>
<tr>
<td>$l_c, l_{c_{max}}$</td>
<td>$m$</td>
<td>pore tube characteristic length</td>
</tr>
<tr>
<td>$m, m^*, m'$</td>
<td></td>
<td>Archie cementation factor</td>
</tr>
<tr>
<td>$N_x, N_y, N_z$</td>
<td></td>
<td>number of nodes in three directions</td>
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<tr>
<td>$n, n^*, n'$</td>
<td></td>
<td>Archie saturation exponent</td>
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<td>$P$</td>
<td>MPa, psi</td>
<td>pressure</td>
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<td>$P_C, P_p$</td>
<td>MPa, psi</td>
<td>confining pressure and pore pressure</td>
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<tr>
<td>$P_c$</td>
<td>MPa, psi</td>
<td>capillary pressure</td>
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<td>atm.</td>
<td>mean pressure</td>
</tr>
<tr>
<td>$Q$</td>
<td>cc/sec</td>
<td>flow rate</td>
</tr>
<tr>
<td>$Q_{sc}$</td>
<td>cc/sec</td>
<td>gas flow rate at standard conditions</td>
</tr>
<tr>
<td>$Q_v, Q_{ve}$</td>
<td>meq/cc</td>
<td>total and effective clay concentration</td>
</tr>
<tr>
<td>$R_e$</td>
<td>$m$</td>
<td>electrical resistance</td>
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<td>$m$</td>
<td>equivalent electrical radius</td>
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<tr>
<td>$R_h$</td>
<td>$m$</td>
<td>hydraulic resistance</td>
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<td>$r_h, r_{he}$</td>
<td>$m$</td>
<td>equivalent hydraulic radius</td>
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<td>$R_{sh}$</td>
<td>ohm $\cdot m$ or ohm $\cdot m$</td>
<td>resistivity of shale</td>
</tr>
<tr>
<td>$R_t, R_o, R_w$</td>
<td>ohm $\cdot m$ or ohm $\cdot m$</td>
<td>resistivity of rock and solution</td>
</tr>
<tr>
<td>$\overline{R}$</td>
<td>$m$</td>
<td>average pore throat radius</td>
</tr>
<tr>
<td>$R^*$</td>
<td>$m$</td>
<td>average radius of curvature at contact point</td>
</tr>
<tr>
<td>$r^*$</td>
<td>$m$</td>
<td>average radius of grains</td>
</tr>
<tr>
<td>$RC$</td>
<td></td>
<td>the ratio of $\frac{R^<em>}{r^</em>}$</td>
</tr>
<tr>
<td>$S$</td>
<td>$m$</td>
<td>nodal pore radius</td>
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<tr>
<td>$S_0, S_w$</td>
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<td>saturation of oil and water</td>
</tr>
<tr>
<td>$s_o$</td>
<td></td>
<td>constant</td>
</tr>
<tr>
<td>$S(l^*<em>{c</em>{max}})$</td>
<td></td>
<td>fraction volume of pore space</td>
</tr>
<tr>
<td>$T$</td>
<td>$^\circ C$</td>
<td>temperature</td>
</tr>
<tr>
<td>$V$</td>
<td>cc</td>
<td>volume</td>
</tr>
<tr>
<td>$V_p$</td>
<td>cc</td>
<td>rock pore volume</td>
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<tr>
<td>$V_{sh}$</td>
<td>cc</td>
<td>shaley volume fraction</td>
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<tr>
<td>$v_{IDL}$</td>
<td></td>
<td>volume fraction of double layer</td>
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<td>$v_Q$</td>
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<td>constant relating to the volume of salt-free water</td>
</tr>
<tr>
<td>$W_c$</td>
<td>grams</td>
<td>total clay content</td>
</tr>
</tbody>
</table>
Greek Letters.

$\alpha$ expansion factor for diffuse layer

$\alpha'$ radius of contact point of grains

$\beta$ equivalent conductivity of clay counterions

$\beta'$ displacement of the centres of grains

$\gamma$ constant

$\theta$ phase angle

$\lambda^c_{Na}$ maximum conductance of counterions

$\mu$ fluid viscosity.

$\nu$ Poisson's ratio for rock matrix or grains

$\sigma'$, $\sigma''$ real and imaginary conductivity

$\tau$ clay distribution coefficient

$\phi$ porosity fraction

$\omega$ temperature coefficient for $\lambda^c_{Na}$
CHAPTER 1

INTRODUCTION
1.1 Preamble

For adequate analysis of petroleum reservoir performance and prediction of its future production behaviour, the engineer must be furnished with sufficient and reliable information about the in situ properties of the reservoir. To this end, properly determined petrophysical characteristics, e.g. porosity, saturation and permeability play a major role as they have direct bearing on the hydrocarbon in place predictions and mechanics of fluid flow in porous media.

There are essentially two well established methods for the determination of the physical properties like porosity and saturation of reservoir rocks, namely open hole well logging interpretation and laboratory core sample analysis. Well logging provides a set of continuous and unbiased physical measurements of rock properties. It is relatively less expensive and quicker than coring; also, in unconsolidated rock, core may be unobtainable, so that logs provide the only continuous data set. However, logging tools need to be calibrated usually based on the results obtained from laboratory core analysis.

Among many different logging techniques (e.g. electrical, magnetic, acoustic and nuclear logging, etc.), electrical logs have been regarded as one of the more ‘reliable’, and therefore more frequently used. The quantitative interpretation of down hole electrical resistivity measurements is based on the presumption that saline formation water in the pores conducts electrical current, whereas hydrocarbons and rock do not. Two famous simple formulas called the Archie equations (Archie 1942), which for the first time related quantitatively porosity and saturation with the electrical resistivity of rocks, have been commonly used in the oil industry:

\[
\frac{R_o}{R_w} = \frac{1}{\phi^2} \quad (1.1)
\]

and

\[
\frac{R_t}{R_o} = \frac{1}{S_w^2} \quad (1.2)
\]

where \(R_w\), \(R_o\) and \(R_t\) are the resistivity of the saline water, the resistivity of formations when fully saturated by water and resistivity of formations when partially
saturated by water respectively.

It has been noticed, however, that clay minerals in shaley rocks provide a second conductive path for the cations in the brine, complicating the situation. Ignoring the effects of the excess conductivity from such clays during the calculation of porosity and hydrocarbon saturation in shaley sands from electrical logs may result in a considerable underestimation of the volume of hydrocarbons present (Waxman and Smits 1968, Clavier et al. 1977). Since reservoirs exist under conditions of high temperature and pressure, a knowledge of the effects of temperature and pressure on the electrical properties of reservoir rocks, therefore, is important in order to relate the rock petrophysical properties measured in the laboratories to those in the in situ reservoir conditions.

The current state of the art measurements of rock electrical properties at high pressures have usually been limited to room temperatures. This limitation results from the well known experimental difficulties such as the inadequacy of facilities and the lengthy period of waiting for the stress and temperature equilibrium. Under the circumstances, the standard practice in the industry has been to use some empirical extrapolation techniques to convert laboratory results to in situ high pressure conditions while ignoring the effect of temperature. In addition, the effects of clay minerals on the electrical properties of reservoir rocks, which have been regarded as perhaps the most complex problem encountered in formation evaluation, remain to be fully understood.

1.2 Objectives of this Research

The main objectives of this research are, therefore, as follows:

a. Experimental determination of the effects of clay, including the clay content, type and distribution, on the electrical properties of reservoir rocks at both room and reservoir conditions,

b. Experimental investigation of the individual and the combined effects of pressure and temperature on the electrical properties of reservoir rocks,

c. Experimental measurements on the effect of pressure, temperature and clay on the absolute permeability of rocks, and finally,
d. Interpretation of the experimental results in the context of predictive models.

1.3 Methods of Investigation

To realise the research objectives, the following methods have been developed and applied:

a. A novel multi-sample high pressure and high temperature rock testing system connected to an automatic data acquisition unit has been set up to measure the electrical and hydraulic properties of five core plugs of 1.5” in diameter and 3” long simultaneously. These rock samples measured include clean (clay-free) sandstones and synthetic shaley sands. The use of this new system increases the speed of testing and, since all the samples are placed in identical conditions, eliminates any experimental comparison errors caused by the fluctuations of pressure and temperature.

b. A new method for making synthetic shaley sands with desired clay type, content and distribution mode has been developed, in order to systematically study the effect of clay minerals on the electrical properties of shaley sands at both room and reservoir conditions.

c. Two 3D computer models of pore space networks have been written for interpreting the effect of clay, pressure and temperature on the electrical and hydraulic properties of both real and synthetic rocks.

1.4 Arrangement of Thesis

In the next chapter, basic theories of electrical conduction through rocks and some empirical relationships between the porosity, saturation and the electrical resistivity are reviewed. Also included in this chapter are the reviews of the previous studies on the effects of pressure and temperature on the electrical properties of rocks. Chapter 3 introduces basic theories of clay mineralogy and the geological explanations of the presence of clays with different distributions in the reservoir rocks. Some existing methods and models for the interpretations of shaley sand conductivities are also reviewed and discussed. Chapter 4 describes the details of the novel multi-sample high pressure and temperature rock testing system and
the experimental procedure employed in this study. Both the individual and the combined effects of pressure and temperature on the electrical properties of sandstone rocks are presented and discussed in Chapter 5. A parametric study is also provided to demonstrate the errors in the estimation of in situ rock properties from electrical logs while ignoring the effect of pressure, temperature and hysteresis during the laboratory calibration of logs. Chapter 6 introduces the new method for making synthetic shaley samples for the study of the clay effect on rock electrical properties at reservoir conditions. A modified version of the W-S model, which includes a temperature coefficient and a clay distribution coefficient, is presented. Chapter 7 reports the results of an experimental study on the effect of clay, pressure and temperature on the absolute permeability of natural and synthetic rocks. In Chapter 8, two 3D pore space petrophysical models are presented. The effect of clay distribution on shaley sand conductivities and the effect of pressure and temperature on the rock electrical and hydraulic properties are numerically simulated. The final chapter provides a summary of the key conclusions of this thesis and suggestions for further work.

References


CHAPTER 2

THEORY OF ELECTRICAL RESISTIVITY AS A MEANS TO DETERMINE ROCK PETROPHYSICAL PROPERTIES
2.1 Introduction

The electrical resistivity ($R$) of a substance is the measure of its resistance to the passage of electrical current. It is usually expressed in units of ohm $\cdot$ m or ohm $\cdot$ cm. The electrical conductivity ($C$) is the inverse of the resistivity, which is often expressed in units of mho/m or mho/cm. It has been found that most rock forming materials in sedimentary formations have very high resistivities (e.g. $> 10^6$ ohm $\cdot$ m). Electronic conduction or metallic electrical conduction plays no important role in most reservoir rocks. The conductive properties of sedimentary rocks are actually of electrolyte origin — the presence of saline water (or mixtures of water and hydrocarbons) in the rock pore space. Because of the electrically non-conductive character of hydrocarbons, the saline water phase in the pore space is the only electrical current path and must of course be continuous. The interpretation of the electrical properties of a particular reservoir rock, therefore, helps the estimation of the quantity of saline water present in the pore spaces, i.e. rock porosity and saturation. In this thesis the word water will be used to imply saline water in the rock pore space.

The resistivity of an in situ rock depends on (Serra 1984):

a. The resistivity of the water in the pores, this varies with the nature and concentration of its dissolved salts.

b. The quantity of water present; i.e. the porosity and saturation.

c. Lithology, i.e. the nature and percentage of clays present, and traces of conductive minerals.

d. The texture of the rock; i.e. distribution of pore sizes, clays and other conductive minerals.

e. The formation temperature.

Because the electrical resistivity of rocks depends on so many factors especially the last three mentioned above, any analytical and exact solution of the petrophysical characteristics such as porosity, saturation and permeability of sedimentary rocks as a function of the electrical properties becomes virtually impossible. However, many empirical equations have been established over the past five decades to enable the practical use of electrical logging data for the interpretation
This chapter reviews the basic concepts of electrical conduction in rocks and the electrical property measurement as a means to determine the petrophysical properties such as porosity and saturation for reservoir rocks. The interrelationships between the electrical properties, porosity, permeability, and pore structure of rocks will be reviewed and discussed. Finally the effects of pressure and temperature on rock electrical properties will also be reviewed and discussed.

2.2 Theory of Electrical Conduction in Rocks

Due to the complex pore structure of rocks, the conduction through rocks can be represented as a system of a combination of many resistors and capacitors in parallel and in series. The impedance of this complex circuit lies somewhere in between two simple cases which are described in Appendix A (i.e., one resistor and one capacitor in series, or in parallel). Since the impedances calculated for rocks are complex quantities, the resistivities (or conductivities), which are calculated from the impedances by Ohm's law while considering the rock geometry factors, are also complex quantities. For a linear isotropic material under a sinusoidally varying electric field, a complex conductivity can be expressed as follows:

\[ \sigma^* = \sigma' + j\sigma'' \quad (2.1) \]

where \( \sigma' \) is the real conductivity and \( \sigma'' \) is the imaginary conductivity. A so-called loss tangent \( (\tan \delta) \) can be written as:

\[ \tan \delta = \frac{\sigma'}{\sigma''} \quad (2.2) \]

The phase angle \( -\theta \) by which the total current density leads the electric field is given by (Lockner and Byerlee 1985):

\[ -\theta = \frac{\pi}{2} - \delta \quad (2.3) \]
The term "conductivity" of rocks is commonly measured as $C_o = \sqrt{\sigma'^2 + \sigma''^2}$. At low frequencies (e.g. $f < 10$ KHz), the real part of the complex conductivity is much greater than the imaginary part ($\sigma' \gg \sigma''$). Thus the phase angle approaches zero ($\phi' \approx 0$), leading to $C_o \approx \sigma'$, i.e. the rock conductivity measured at these low frequencies is almost independent of frequency. At high frequencies, the complex conductivity (or resistivity) and the phase angle depend on the frequency, rock types, clay contents, pressure and temperature (King 1977, King et al. 1982, Lockner and Byerlee 1985). However, the complex conductivity study is beyond the scope of this thesis. In all the following chapters, only the real conductivity and resistivity, which are not dependent on frequency, will be concerned.

2.3 The Archie Type Equations

Although the era of formation evaluation using logging technique began from the first ever well-log, a measurement of electrical resistivity, conducted by the Schlumberger brothers in September 1927, the quantitative interpretation of well-log results became possible only after the early 1940’s. Archie (1942) defined formation resistivity factor ($F$), also written as FF or FRF, for formations completely saturated by brine as:

$$ F = \frac{R_o}{R_w} \quad (2.4) $$

where $R_o =$ resistivity of the sand fully saturated with brine, $R_w =$ resistivity of the brine. Based on the experimental studies of the relation between porosity and formation factor for sandstone cores from USA Gulf Coast oil reservoirs, the following empirical relation was found by Archie:

$$ F = \frac{1}{\phi^m} \quad (2.5) $$

where $\phi =$ porosity fraction of the sand and $m = 2$ — a cementation factor as defined by Guyod (1944), which is the slope of the $log \ F \ vs. \ log \ \phi$ plot as shown in Fig.2.1.
Winsauer et al. (1952), after studying 40 sandstone cores from a wide range of formations, proposed two empirical formulas:

\[ F = \frac{1}{\phi - 0.06}^{1.48} \]  \hspace{1cm} (2.6)

and

\[ F = \frac{0.62}{\phi^{2.15}} \] \hspace{1cm} (2.7)

Equation (2.7) is also called Humble equation. The following formula is often called Tixier equation which is similar to the Humble equation but more convenient to use manually:

\[ F = \frac{0.81}{\phi^{2}} \] \hspace{1cm} (2.8)

There are many Archie type equations available in the literature for various reservoirs. In a general form, these modified Archie equations can be written as:
where $a$ and $m$ are empirical constants which are related to the pore geometry. Compared with equation (2.5), equation (2.9) is often cited because the extra degree of freedom provided by the second parameter ($a$) improves the degree of fit of a given data set. From the definition of formation resistivity factor, it is expected that $F = 1$ at $\phi = 1$, but many modified Archie equations in the form of equation (2.9) when constant $a \neq 1$, do not satisfy this constraint. For practical purposes, however, this is not a serious deficiency as long as the relation between porosity and resistivity is sufficiently accurate over the porosity range of interest.

For hydrocarbon bearing formations, Archie observed increases in resistivity and defined a new term called formation resistivity index ($I$) as follows:

$$
I = \frac{R_t}{R_o} \tag{2.10}
$$

where $R_t$ is the true resistivity of hydrocarbon bearing formations, and $R_o$ is the resistivity of the same formation when it is fully saturated by water. Formation resistivity index ($I$) was related to the saturation by Archie as follows:

$$
\frac{R_t}{R_o} = I = \frac{1}{S_w^n} \tag{2.11}
$$

where $S_w$ is the water saturation which is defined as the fraction of the porosity occupied by water, and $n$ is the Archie saturation exponent which can be determined experimentally by plotting $\log I$ vs. $\log S_w$ as demonstrated in Fig.2.2.

The saturation exponent $n$ varies with rock type and with the distribution of the brine and the non-conducting fluids within the pore spaces. Typically it has a value of $2 \pm 0.5$ for many reservoirs encountered. If water tends to spread on the pore wall surface in preference to oil, the rock is said to be water-wet as opposed to oil-wet. Usually water exists initially as the continuous phase covering the inner pore surfaces in water-wet rocks and provides good continuity for electrical conduction. If rocks are oil-wet, oil becomes the continuous phase, water occurs as
isolated droplets, and resistivity becomes much higher. Consequently, the value of
\( n \) can be much greater than 2 in oil-wet rocks (Hearst and Nelson 1985). The effect
of wettability on saturation exponent \( (n) \) is not addressed here and is a subject of
further research.

\[ \text{Equation of line is } \frac{R_l}{R_o} = (1 - S_w) \cdot (1 - S_o)^2 \]

**Fig.2.2 Resistivity index vs. saturation for a Berea sandstone sample**
(after Archer and Wall 1986)

2.4 The Relation between Resistivity, Porosity,
Permeability and Pore Structure of Rocks

As reviewed earlier, Archie related the electrical resistivity to the porosity and
saturation of reservoir rocks. Although there was only one variable \( (m) \) involved,
later extended to two \( (a \) and \( m) \), the fit between the experimental data and the
Archie equation was amazingly good for those rocks from USA Gulf Coast. For
other rock types, however, modifications may be needed to use Archie type of
equations due to the empirical and non-precise basis. This raised a new research
topic for petroleum engineers and geophysicists to understand the theoretical foun-
dations of the electrical conduction in rocks.

Wyllie and Rose (1950) examined the theoretical basis of Archie equations
based on the Kozeny-Carmen equation (Kozeny 1927, Carmen 1938) for fluid flow

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in porous media and the capillary pressure phenomena. A definition of tortuosity was given as $\tau = \left(\frac{L_t}{L}\right)^2$ when representing the rock pore system by many simplified single fluid filled channels with a rather complex shape but of constant cross sectional area. $L_t$ is the total tortuous length of this pore channel which is always greater than the actual length ($L$) of the porous media. It was concluded by Wyllie and Rose that formation resistivity factor, cementation factor and constant (a) in Archie equations depend on not only rock porosity but also rock texture or pore tortuosity. Modified Kozeny equations correlating permeability, formation factor, cementation factor, saturation and capillary pressure were developed.

Winsauer et al. (1952) further studied the effect of pore tortuosity on the electrical properties of sands. They defined tortuosity as $\tau = \frac{L_t}{L}$ where $L_t$ and $L$ were the same as defined by Wyllie and Rose (1950). This definition of tortuosity has been more commonly used mainly because of its clear physical meaning. The formation resistivity factors of these sandstones of widely different properties were found to be related to their porosities and tortuosities. As a result of their theoretical studies, two popular Archie type empirical equations (equation (2.6) and (2.7)) were proposed.

A physical model was presented by Owen (1952) in which the pore space consists of a system of voids and interconnected tubes to account for some high formation factor and cementation factor of rocks. Relationships between porosity and formation resistivity factor were determined by experimentally measuring the void cube resistance and then calculating the resistance of the pore space network. A concept of pore constriction was suggested in addition to pore tortuosity to explain the electrical properties of natural porous media.

Formation resistivity factors of unconsolidated porous media were found to be related to the particle shape and cementation by Wyllie and Gregory (1953). Aggregates of spheres in the porosity range 12-56% and of cubes, cylinders, discs and triangular prisms in the porosity range 30-45% were used in their experiments. For consolidated sands, the Archie equation in the general form as equation (2.9) can be applied to relate porosity to the electrical resistivity. According to Wyllie and Gregory, it is also possible to estimate the porosity and resistivity of the original unconsolidated sand before cementation commenced, if the particles are all perfect spheres, by extrapolating the straight line ($\log F$ vs. $\log \phi$) to the origin point.
Atkins and Smith (1961) further investigated the effect of particle shape on the formation factor - porosity relationship. The cementation factor ($m$), which was called “shape factor”, was found to be constant for a given rock system with certain particle shapes. If rocks were taken from different reservoirs, presumably with different types of grain size distributions, different values of $a$ and $m$ in the Archie equation should be used to ensure the accuracy of the empirical equation.

Electrical conduction through porous media was modelled by Shankland and Waff (1974) with a simple array of 2340 resistors from which resistors were removed at random to simulate a decrease in porosity. Percolation theory, which suggests that there is a critical fraction of branches or bonds that must exist before the probability of a complete connection across a large cluster of such bonds is finite (Sykes and Essam 1964, Shante and Kirkpatrick 1971), was tested experimentally by Shankland and Waff. An insight into the mechanisms responsible for the Archie’s law dependence of electrical conduction on porosity was revealed. This insight provided a “conductivity model” that emphasises the importance of both the conductive space and the interconnections of conductive regions.

Since $m$ is a pore geometry factor and permeability of rocks is related to pore geometry, Raiga-Clemenceau (1977) deduced by logic the following empirical equation to relate cementation factor($m$) to rock permeability ($k$):

$$m = \frac{\log F}{\log \phi} = 1.28 + \frac{2}{\log k + 2} \quad (2.12)$$

This equation was used to estimate $m$ from permeability data for some reservoirs and was found to be more convenient to use compared with the Humble equation. If equations like (2.12) exist for all the reservoirs, it might become possible to derive permeability values of reservoirs when other methods for permeability determination are not available. However, for a particular reservoir comprehensive experimental data base is always needed to relate accurately the permeability with porosity by simple equations like (2.12).

Brace (1977) examined experimentally the following equation (Wyllie and Spangler 1952, Hubbert 1956, Brace et al. 1965), which relates fluid flow and electrical conductivity in rocks, based on the Poiseuille’s law:
where $k_o$ is a shape factor which can vary between 2 to 3, and $R_h$ is the hydraulic radius, which is the volume of the interconnected pores divided by their surface area. Combining equation (2.13) with the Archie's empirical law (equation (2.5)), the following equation was obtained by Brace:

$$k = \frac{R_h^2}{k_o F^2 q^2}$$

Based on equation (2.14), experimental results measured by Brace and published in the literature on two granites and a number of sandstones and ceramics were used to estimate the permeabilities of these rocks. Predicted and measured permeability agreed to within about a factor of 2 over the 9 orders of magnitude range of permeability for those samples tested. Although equation (2.14) cannot be applied directly as a predictive tool in practice, it provides a base for possible correlations between rock petrophysical characteristics after refinement and further investigation.

A laboratory investigation was made on formation factor-porosity relationships by Jackson et al. (1978), using natural and artificial sand samples with a wide range of grain size and different grain shapes. It was noticed that all samples obeyed Archie's law in the form of equation (2.5) and that $m$ was dependent on the shape of particles, increasing as they became less spherical, while variations in size and spread of size appeared to have little effect.

Hagiwara (1984) substituted Archie's law into the Swanson (1981) result in order to relate cementation factor, permeability and average pore radius of rocks. The following empirical equation was proposed:

$$k = C \phi^m \bar{R}^2$$

where $C$ is a constant and $\bar{R}$ is the average pore throat radius determined from the air-mercury capillary pressure curve. This equation, which was derived based on
the bundle of tube pore space model following the procedure presented by Purcell (1949), agreed with the experimental data when an average pore radius obtained from capillary pressure derived pore size distribution was used. However two empirical parameters \((C\) and \(\bar{R}\)) are needed in the equation to calculate permeability, which limits the general application of the equation.

Katz and Thompson (1986) reported another model for relating absolute permeability to electrical conductivity of rocks. Their key result is as follows:

\[
k = \frac{c l_c^2 C_o}{C_w}
\]  

(2.16)

where \(c\) is a constant of the order of \((1/226)\), and \(l_c\) is a so-called characteristic length which may be determined experimentally from the threshold pressure in a mercury injection experiment. The threshold pressure, as determined from both mercury injection and electrical conductivity measurements, defines the point at which the invading mercury first forms a connected path spanning the rock sample. According to Katz and Thompson, absolute permeabilities predicted from equation (2.16) containing no adjustable parameters agree with measured values with an accuracy to ±2%. Katz and Thompson (1987) soon extended their previous study (Katz and Thompson 1986) to calculate electrical conductivity of rocks:

\[
\frac{C_o}{C_w} = \frac{l_c}{l_{\text{max}}} \phi S(l_{\text{max}})
\]

(2.17)

where \(l_c\) and \(l_{\text{max}}\) are experimentally defined characteristic length for electrical conduction in rocks, and \(S(l_{\text{max}})\) is the fractional volume of connected pore space involving pore widths of size \(l_{\text{max}}\) and larger. Equation (2.16) and (2.17) are both based on percolation ideas. No adjustable parameters are needed, i.e., all variables involved in both equations can be determined from the mercury injection capillary pressure experiments, to predict permeability and conductivity. It is important to note, however, that the calculation of \(l_c\), \(l_{\text{max}}\) and \(S(l_{\text{max}})\) is based on a highly idealised pore space model which ignores the effect of pore constrictions. Any information on the pore sizes and pore size distribution obtained, therefore, can only be regarded as semi-quantitative.
Electrical conductivity and hydraulic permeability of clay-free rocks have been related to the geometry of pore space using image processing techniques. In two dimensions the pore network of weakly cemented sandstones appears as long chains of pore chambers connected by narrow passages. Rink and Schopper (1978) used erosion and dilation to remove the small bridges connecting the pores, and subdivide the two-dimensional pore system into a collection of discrete "void particles" with simple convex shapes. Using the bundle of tubes model, they then calculated the permeability from pore size histograms constructed by measuring the dimensions of the artificially individualised pore elements. An order of magnitude agreement was obtained between measured and predicted permeability values. Using digitised scanning electron microscope images of rock microsections, Berryman and Blair (1986) estimated porosity and specific surface area from measured two-point spatial correlation functions. These two parameters were then combined with known values of the formation resistivity factor to predict permeability from Kozeny-Carmen equations. Pore casts of sandstone (Pittman 1984) revealed that the void space forms a complicated multiply connected three-dimensional volume, and a priori it is not clear that a cross section across a statistically homogeneous and isotropic rock sample contains enough information about the geometry and topology of the pore system to predict the macroscopic three-dimensional flow properties. Using image analysis techniques, Ehrlich et al. (1984) studied empirical correlations between permeability and various geometrical attributes of the pore space extracted from digitised and segmented thin sections of sandstone. They showed that a significant degree of correlation exists between the macroscopic transport properties and geometrical features such as throat size histograms or two-dimensional pore connectedness. One important conclusion of their work is that the changes of the three-dimensional pore structure that control the variations of the transport coefficients are reflected in the microsections.

Since both electrical conductivity and hydraulic permeability reflect the geometry and topology of the network of microscopic flow channels in sandstone, in principle, they can be calculated by solving Navier-Stokes and Laplace's equations, respectively, in the pore space. Practically, this approach is rendered intractable by the complexity of the boundary conditions, which must be imposed at the irregular pore-grain interface. Doyen (1988) studied both conductivity and permeability of a set of sandstone samples with the same lithology but with various porosity values from 5% to 25%. The effective medium theory was employed to homogenise the irregular real rock pore space, therefore, to construct a simpli-
fied equivalent pore system after expanding uniformly the flow channels about the branches forming the skeleton of the pore network. This dilation operation gave rise to a microscopically homogeneous pore system in which all the flow channels are identical cylinders with the same equivalent electrical radius \( r_e \) and the same equivalent hydraulic radius \( r_h \). Fig.2.3 illustrates the process of simplifying the microscopically inhomogeneous pore system (a) to the homogeneous pore system (b) by dilating uniformly the skeleton into a network of cylindrical flow channels.

Both \( r_e \) and \( r_h \) were determined self-consistently from the experimental throat size distribution. In the calculation, both the electrical resistance and the hydraulic resistance of the voids (nodal pores) were neglected. Very good agreement was achieved between the predicted values and experimental results.

So far it is well known that the pore space of sedimentary rocks controls or influences most of the rock petrophysical properties, such as electrical resistivity, porosity, permeability, compressibility and elastic wave velocity. However, because of the complexity and variability of the pore spaces of a given rock and because of the wide range of pore size, pore shape and rock matrix composition found between various rocks, realistic and quantitative models which can relate these various rock petrophysical properties for a wide range of rock types are very difficult to
The "fractal" concept has been recently developed (Mandlebrot 1982), based on partly probability theory and partly algebra theory (e.g. topology), to describe the irregular or fragmented geometries often found in nature. The rough surfaces of objects should have fractional dimensions of $2 < D < 3$. The higher the value of $D$ the more convoluted and irregular the surface will be. The advantage in using fractals in the study of rock pore structures is that the degree of the pore surface roughness can be described by a number rather than many words. For quantitative study of flow of fluids, electrical current and heat in porous media, however, the possible application of fractals remains as a matter of investigation.

Another group of studies involving the relationships between resistivity, permeability, porosity and pore structures is the pore space network modelling. Networks have become fairly common tools for modelling rock transport properties since they can simulate the interconnectedness of real rock pore space. Details of network modelling will be discussed in Chapter 8.

Although the experimental and theoretical studies reviewed above progressively revealed some aspects of the mechanisms of electrical conduction in porous rocks and how these petrophysical characteristics are related, no firm conclusion has yet been reached and, therefore, no single empirical equation reviewed in this section may be used for a given reservoir rock without the support of reliable experimental data.

Since most oil reservoirs exist at great depth subsurface under conditions of high pressure and temperature, a knowledge of the effects of pressure and temperature on electrical properties of reservoir rocks is important to convert room condition laboratory measurements of rock petrophysical properties into in situ reservoir condition real values. This has led to numerous studies on the effects of confining pressure and more recently formation temperature on these rock characteristics such as porosity (i.e. compressibility), electrical resistivity, permeability, relative permeability, acoustic velocity, and capillary pressure to various pore fluids. In the following sections, the previous studies on the effect of pressure and temperature on the electrical properties of reservoir rocks will be reviewed and discussed.
2.5 The Effect of Pressure

Many investigators have studied the effect of confining pressure on the formation resistivity factor and the cementation factor of various rocks. In this thesis the word confining pressure will be used to imply net confining pressure which is the difference between external confining pressure and internal pore pressure. Most of the previous studies were performed using sandstone rocks, although there are also a few experiments on carbonate rocks, crystalline rocks, glass beads and sands bonded with epoxy resins. Investigations by Fatt (1957) revealed that formation factor increases with an increase in applied pressure and that the $F - \phi$ relationship is pressure dependent. As much as 35% increase of formation factor under a net confining pressure of 34.5 MPa (5000 psi) was reported by Fatt, which indicates that a formation factor measured in situ at great depths would differ significantly from one measured in the laboratory, if the measurement is not conducted under the same net confining pressure. Fatt also concluded that the pressure effect is more pronounced for clean sands than for shaley sands, and that laboratory measurements of formation resistivity factor, in which only external pressure is varied, are sufficient to study the effect of overburden pressure. Similar results were also reported by Wyble (1958) in the study of the effects of pressure on formation factor, permeability and porosity. An increase of Archie cementation factor together with formation factor with confining pressure was observed. The experimental observation was attributed by Wyble to the closure of small crack-like pore space presented in sandstone and crystalline rocks. Glanville (1959) showed an increase of formation factor with pressure and greater effect in less porous, less permeable rocks. To the contrary, Redmond (1962) reported a decrease in formation factor and cementation factor with pressure especially for high porosity sandstone rocks. Helander and Campbell (1966) observed increase in formation factor and cementation factor with pressure and attributed the change to mostly an increase in the pore constriction factor. The reports of Brace et al. (1965), Brace and Orange (1968) and Timur et al. (1972) also confirmed the significant increases in formation factor by net confining pressures of the same magnitude as in reservoirs. A review of the studies of the electrical properties at high pressures was given by Parkhomenko (1982) showing that the electrical resistivity at high pressures is related to other rock properties such as porosity, permeability, rock structure and pore geometry. For carbonate rocks, Longeron et al. (1986) noticed less variation in their formation factor and cementation factor with pressure com-
pared with sandstone rocks. Recently, Mahmood et al. (1988) reported increase in formation factor and cementation factor with confining pressure. They confirmed the conclusion by Fatt (1957) and King (1965) that the net confining pressure (confining pressure - pore pressure) influences the transport and elastic properties of rocks, but not the individual confining pressure and pore pressure values.

Only limited research has been reported on the effect of pressure on the formation resistivity index ($I$) and the saturation exponent ($n$). Both increase and decrease of saturation exponent with an increase of pressure have been reported in the literature. Glanville (1959) found that $n$ increased with an increase of confining pressure for two sandstones, two limestones, and one dolomite. He attributed the experimental observation to that small capillaries, which are fully saturated with brine (for water-wetting reservoir rocks only), are compressed in a greater amount than the large ones, and that fluid redistributions may also play some roles. A small increase of $n$ with net confining pressure up to 34.5 MPa (5000 psi) was also observed by Mahmood et al. (1988). Longeron et al. found, however, that $n$ may increase or decrease with an increase in net confining pressure depending on the type of rock.

### 2.6 The Effect of Temperature

The effect of temperature on formation factor has been investigated by Hilchie (1964) using consolidated sandstone and limestone samples. It was indicated that as the temperature increased while the net confining pressure remained constant, the formation factor went through a minimum after which it increased. According to Hilchie, this significant change of formation factor with temperature was a function of the percent of small pores of radius less than 0.5 micron and the clay content. Helander and Campbell (1966) presented their results of resistivity measurements on six synthetic bead cores and one synthetic sand core bonded by an epoxy resin at varying conditions of pressure up to 69 MPa (10,000 psi) and temperature up to 160 °C. A definite trend of change of formation factor with pressure was noticed due to the changes of rock tortuosity, pore constriction and the change of the electrochemical double layer. The effect of temperature on formation factor was not as well defined as the pressure effect because of the much greater experimental difficulty. Sanyal (1972, 1973) reported results of formation
factor measurements at different temperatures to a maximum of 149 °C using three sandstone and one limestone samples. He reported that the relative formation factor, which was defined as the ratio of formation factor at high temperatures to the formation factor at ambient temperatures, increased with temperature and showed hysteresis between the heating and cooling sequence runs. A decrease in apparent formation factors with increasing temperature was found experimentally by Waxman and Thomas (1974) and was attributed to the effect of clay cation exchange capacity. The results by Brannan and Gonten (1973) also indicated the significant effect of temperature on formation factor. An increase in temperature from ambient conditions to 150 °C resulted in an increase in the formation factor from 55% to 106% for three samples with brine resistivities from 5 to 20 ohm·cm. According to Brannan and Gonten, since the cation exchange capacity associated with the clay was not changed, the change in formation factor with temperature may possibly be a function of pore constriction. Kern et al. (1977) conducted electrical conductivity measurements on fully water saturated sandstones, in order to obtain excess clay conductivity. They concluded that the electrical conductivity of these shaley sandstones at constant brine salinity varies linearly with temperature in °C, and the electrical conductivity associated with shaliness of a sandstone varies linearly with temperature in °C in a manner similar to the electrical conductivity of brine solutions. The formation factor values calculated from the experimental results by Kern et al. were either constant or decreasing as the temperature increased and depended on the clay content of the samples. Ucok (1979) reported the results of electrical resistivity of rock samples and aqueous solutions of the chlorides of sodium, potassium and calcium as a function of temperature. It was found that the resistivity of aqueous solution decreased sharply with increasing temperature, went through a minimum and then increased again. The formation factor of clean sandstone samples was independent of temperature up to 150 °C. Beyond 175 °C a clear increase in formation factor was noticed and attributed to the structure changes inside the cores as a result of thermal expansion. For a sample with strong surface conduction, a decrease in formation factor was observed at temperatures below 150 °C. Above 150 °C, the pore structural resistance due to the heating contributed to the total resistance and, therefore, led to an increase of formation factor. The experimental data presented by Parkhomenko (1982) revealed that the formation factor of limestone and shaley sandstone rocks was temperature dependent. Various degrees of decrease in formation factor with temperature were observed for shaley sandstones. The temperature effect on formation factor of
limestones, however, was relatively insignificant. Mahmood et al. (1988) found that no noticeable effect of temperature on formation factor and cementation factor was found for most of the rock samples tested. Table 2.1 summaries the results of many previous studies on the effect of temperature on formation factor.

Hilchie’s work (1964) is one of the few studies reported on the combined effect of pressure and temperature on the electrical properties of reservoir rocks. He concluded that at low to moderate temperatures, the combined effect of pressure and temperature was equal to the sum of the two individual effects.

The following conclusions can be drawn based on the above literature survey:

a. Except Redmond’s (1962) conflicting results, overwhelming majority of the findings by previous authors support the idea that as the confining pressure increases, the formation resistivity factor (F) also increases. Although most of these measurements were carried out at room temperatures, they signified the influence of pressure dependency of F on the volumetric estimations of hydrocarbons.

b. There is a conflict between the findings of these previous research works on the pressure and temperature dependency of formation resistivity index and saturation exponent. The volume of works reported in the literature on this aspect is also extremely limited and a clear trend is yet to be established.

c. There is a greater confusion in determining the effects of temperature on F and m. While some authors like Mahmood et al. (1988) reported that the temperature dependency of F and cementation factor (m) is negligible, many others like Hilchie (1964), Helander and Campbell (1966), Sanyal (1972, 1973), Brannan and Gonten (1973), Waxman and Thomas (1974) reported an appreciable change of F as temperature changes. It is believed that the confusion arises mainly due to the inadequacy of the experiments and, therefore, the inadequacy of high quality experimental data.

d. The experimental work on the combined effects of pressure and temperature is extremely limited. No firm conclusion has yet been reached in this aspect.
Table 2.1 Summary of Previous Studies

<table>
<thead>
<tr>
<th>Investigator</th>
<th>Types of cores</th>
<th>P, T conditions</th>
<th>Typical Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hilchie (1964)</td>
<td>Boise sandstone, Berea sandstone,</td>
<td>P &lt; 69 MPa, T &lt; 200 °C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bandera sandstone, Limestone</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Helander &amp; Campbell (1966)</td>
<td>Synthetic beads, Synthetic sands</td>
<td>P &lt; 69 MPa, T &lt; 160 °C</td>
<td></td>
</tr>
<tr>
<td>Sanyal (1972)</td>
<td>Boise sandstone, Berea sandstone,</td>
<td>P = 2.2 MPa, T &lt; 149 °C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bandera sandstone, Limestone</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brannan &amp; Gonten (1973)</td>
<td>Berea sandstone, Paluxy sandstone</td>
<td>P = 3.8 MPa, T &lt; 187 °C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(with clay)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waxman &amp; Thomas (1974)</td>
<td>Shaley sands</td>
<td>P = 6.9 MPa, T &lt; 200 °C</td>
<td></td>
</tr>
<tr>
<td>Kern, Hoyer &amp; Spann (1977)</td>
<td>Shaley sands, Muffled Berea sandstone</td>
<td>P = 2.8 MPa, T &lt; 120 °C</td>
<td></td>
</tr>
<tr>
<td>Ucok (1982)</td>
<td>Berea sandstone, Boise sandstone,</td>
<td>P = 31 MPa, T &lt; 350 °C</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hawaiian basalt</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Parkhomenko (1982)</td>
<td>Shaley sands, Limestone</td>
<td>P = 10 MPa, T &lt; 250 °C</td>
<td></td>
</tr>
</tbody>
</table>

“...” line for clean sandstone and limestone cores
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Glanville, R.R. Laboratory study indicates significant effects of pressure on resistivity of reservoir rock. *JPT,* (April, 1959), p.20.


Longeron, D.G., Argaud, M.J. and Feraud, J.P. Effect of overburden pressure, nature, and microscopic distribution of the fluids on electrical properties of rock samples. *61st SPE Annual Technical Conference and Exhibition, SPE*


CHAPTER 3

REVIEW OF SHALEY SAND CONDUCTIVITY MODELS
3.1 Introduction

Electrical properties are measured in boreholes to determine the porosity and the hydrocarbon saturation of reservoir rocks. This is based on the presumption that saline formation water in pores conducts electrical current, whereas hydrocarbons do not. It has been noticed ever since the early 1950's, however, that clay minerals in reservoir rocks can provide a second conductive path for cations in the brine, complicating the situation. Fig. 3.1 illustrates schematically the water saturated formation conductivity ($C_o$) as a function of formation water conductivity ($C_w$) for shaley sands in a curved solid line and for clean (clay-free) sands in a straight dashed line.

Ignoring the effects of the excess conductivity of clays during the calculation of porosity and hydrocarbon saturation in shaley sands from the electrical logs may result in underestimation of the volume of hydrocarbon reserves.

The effect of clay minerals on the electrical properties of reservoir rocks has been recognized as being perhaps the most complex problem encountered in formation evaluation. Over the past five decades, attempts to solve the interpretation problems of shaley sands have resulted in the establishment of numerous empirical techniques and some idealized and over-simplified conceptual models based on some physical laws to predict the conductive behaviour of shaley sands.
This chapter reviews some existing models for the interpretations of shaley sand conductivities. A brief introduction to the clay mineralogy and some geological background of the presence of clays with different distributions in the reservoir rocks are also given. Finally limitations in using existing shaley sand models and problems encountered during the interpretations are discussed.

3.2 Background of Clay Mineralogy

The term "clay" may be defined as a natural, earthy and fine-grained material which develops plasticity when mixed with a limited amount of water (Grim 1968). Chemical analyses of clays show them to be composed essentially of silica, alumina, and water, frequently with appreciable quantities of iron, alkalies and alkaline earths. The maximum size of particles in the clay size grade is defined differently in different disciplines. For instance, in petroleum industry, the tendency has been to define clay as material with grain sizes less than 1/256 mm. Table 3.1 gives an example of the classification of clastic rocks according to their texture (Jorden and Campbell 1984).

Clay minerals have a sheet structure similar to that of mica in which the principal building elements are (a) sheet of silicon and oxygen atoms in a tetrahedral arrangement, and (b) sheet of aluminium, oxygen and hydroxy 1 atoms in an octahedral arrangement (van Olphen 1963). The four principal groups of clays, namely kaolinite, montmorillonite, illite and sedimentary chlorite, all have essentially these two building elements mentioned, but with different arrangements as shown in Table 3.2 by Grim (1968).

The crystal structures of clays are responsible for many typical clay properties such as ion exchange, swelling, sorption, dehydration and rehydration etc.. Since this thesis deals with the electrical properties of rocks, the ion exchange phenomenon is described here in detail. As shown in Table 3.2, a montmorillonite crystal is composed of two unit layers. Each unit is characterized by a three-sheet lattice in which there are two tetrahedral sheets and an octahedral one sandwiched in between. The unit layers are held together rather loosely in the c-direction which is perpendicular to the crystal layers as shown in Table 3.2, with water occupying the interlayer spaces. In the tetrahedral sheet, some tetravalent silica ($Si^{4+}$) may be partially replaced by trivalent aluminium ($Al^{3+}$), while in the
Table 3.1 Classification of clastic rocks according to texture (after Jorden and Campbell 1984).
### TABLE 2.4—CLASSIFICATION OF CLAY MINERALS (after Grim)

<table>
<thead>
<tr>
<th>Basic Classification and Nomenclature</th>
<th>Definitions, Species, and Additional Data</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>I Two-layer type</strong></td>
<td></td>
</tr>
<tr>
<td>A. Kaolinite group</td>
<td>Sheet Structure: one silica tetrahedral sheet + one alumina octahedral sheet = a unit layer. Very little ion substitution occurs.</td>
</tr>
<tr>
<td>B. Halloysite group</td>
<td>kaolinite, nacrite, dickite, anauxite halloysite</td>
</tr>
<tr>
<td><strong>II Three-layer type</strong></td>
<td></td>
</tr>
<tr>
<td>A. Expanding lattice</td>
<td>Sheet Structure: one alumina dioctahedral sheet (gibbsite) or magnesia trioctahedral sheet (brucite) sandwiched between two silica tetrahedral sheets = a unit layer. Al substituted for Si in tetrahedral sheet. Mg or Fe, Cr, Zn, Li, etc.) substituted for Al in octahedral sheet to form various montmorillonite species. Excess negative charge compensated by exchangeable cations.</td>
</tr>
<tr>
<td>1. Montmorillonite (Smectite) group</td>
<td>montmorillonite, volkonskoite, sauconite, montmorone, saponite, hectorite, vermiculite</td>
</tr>
<tr>
<td>2. Vermiculite group</td>
<td></td>
</tr>
<tr>
<td>B. Non-expanding lattice</td>
<td>Sheet Structure: one dioctahedral or trioctahedral sheet sandwiched between two silica tetrahedral sheets = unit layer. One Al always substituted for one Si in tetrahedral sheet; excess negative charge compensated by fixed K. Various ion substitutions in both tetrahedral and octahedral sheets form various illite species; excess negative charge compensated by K and exchangeable ions.</td>
</tr>
<tr>
<td>1. Illite group</td>
<td>illite, glauconite</td>
</tr>
<tr>
<td><strong>III Regular mixed-layer type</strong></td>
<td>Sheet Structure: ordered stacking of alternate layers of different types.</td>
</tr>
<tr>
<td>A. Chlorite group</td>
<td>alternate layers of montmorillonite-type unit layer and a magnesia trioctahedral sheet (brucite)</td>
</tr>
<tr>
<td><strong>IV Chain-structure type</strong></td>
<td>Chain Structure: chains of silica tetrahedral sheets linked by octahedral groups (oxygens and hydroxyls containing aluminum and magnesium)</td>
</tr>
<tr>
<td>A. Attapulgite</td>
<td></td>
</tr>
<tr>
<td>B. Sepiolite</td>
<td></td>
</tr>
<tr>
<td>C. Palygorskite</td>
<td></td>
</tr>
</tbody>
</table>

Table 3.2 Classification of clay minerals (after Grim 1968).
octahedral sheet, there may be a replacement of $\text{Al}^{3+}$ by divalent $\text{Mg}^{2+}$, or some other cations like iron, chromium, zinc and lithium, without a complete filling of the vacant positions. When the ion exchange happens, some excess negative charges may be generated on the surface of the clay crystal.

In the presence of a saline solution, the counterions such as $\text{Mg}^{2+}$, $\text{Na}^+$ and $\text{Ca}^{2+}$ on the layer surfaces may also be exchanged by other cations. The total amount of the exchangeable cations of clays can be determined analytically by the so-called cation-exchange capacity (CEC) measurements. Table 3.3 lists the ranges of CEC for some clays after Grim (1968). The difference in CEC values of these clays may also be explained by studying their crystal structures. For instance montmorillonite has the highest value of CEC because there are more exchangeable counterions such as $\text{Mg}^{2+}$, $\text{Na}^+$ and $\text{Ca}^{2+}$ between the two unit crystal layers.

<table>
<thead>
<tr>
<th>Clay Type</th>
<th>CEC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaolinite</td>
<td>3 - 15</td>
</tr>
<tr>
<td>Montmorillonite</td>
<td>80 - 150</td>
</tr>
<tr>
<td>Illite</td>
<td>10 - 40</td>
</tr>
<tr>
<td>Chlorite</td>
<td>10 - 40</td>
</tr>
</tbody>
</table>

3.3 Distributions of Clay in Shaley Sands

Clay minerals are often found in clastic reservoir rocks. Petrographic thin section examination provides a means for estimating clay distribution in rocks. More detailed description of clay distribution, morphology and shapes can be obtained from the SEM photomicrographic analysis. Three essentially different forms of clay distribution have been recognised: dispersed, laminated and structural as shown in Fig.3.2.

"Dispersed clay" is the main mode of occurrence of diagenetic clays. It is
Fig. 3.2 Clay distribution models.

a) Dispersed

b) Laminated

c) Structural

- Clay
- Sand
developed by the precipitation of clay crystals from pore fluids, in response to changes in pore water chemistry as a result of changes of temperature and pressure conditions during the process of burial and compaction of sediments. Subsequently, dispersed clays grow within the pore fluid system and are usually attached to sand grain surfaces.

Dispersed clays may occur in rock pore structures as (a) discrete particles, (b) intergrown crystals lining on the pore walls forming a relatively thin and continuous coating and (c) crystals extending far into, or completely across, a pore or pore throat creating a so-called "bridge effect" when clay crystals grow across the pore (Neasham 1977). Dispersed clays often reduce the rock porosity and permeability significantly.

"Laminated clays" are of detrital origin, i.e. they are formed outside the sandstone framework and then moved into the rock system. They appear as thin laminae and sometimes act as vertical flow barriers.

"Structural clays" are of diagenetic origin, i.e. they are formed within the sand framework. One source of diagenetic clay is the in situ alteration of non-quartz particles with interstitial saline solution. A typical example is the alteration of feldspar to kaolinite and hornblende to chlorite. Also considered as structural clays are those originated when pellets or clasts of clays are deposited as an integral part of a rock matrix predominated by sand.

When clays in rocks are in the form of thin layers (also called shales), the conductivity contribution from the diffuse layer is substantially higher than that from the same amount of interstitial clays (Raiga-Clemenceau 1988). Although several simple analytical models (Poupon et al. 1954 and Haley 1979) have considered the case of laminated clay distribution, most of the existing shaley sand conductivity models are only applicable to the shaley sands containing uniformly distributed dispersed clays. After comparing the results of clay concentration from membrane potential measurements and from conductometric titration measurements on some shaley rock samples, de Waal (1989) recently indicated the significant influence of clay distribution on electrical conductivity of shaley sands.

So far, it appears that no systematic study has been reported which reveals the mechanisms of clay distribution on shaley sand conductivities. This thesis, therefore addresses both experimental and numerical model results on the effect of clay distribution on shlaey sand conductive behaviour. Details will be discussed
3.4 Early Empirical Interpretation Models for Shaley Sands

Patnode and Wyllie (1950) noticed that sands containing shale or clay may exhibit abnormally low formation resistivity factors when the saturating solution resistivity is fairly high. The Archie equations are no longer applied here for the interpretation of the porosity and saturation of these reservoirs. Instead they assumed that the conductivity of a shaley sand saturated with an electrolyte may be represented as the sum of two quantities: solution conduction in parallel with solid conduction. An expression for 100% brine saturated shaley sand is given by Patnode and Wyllie as:

\[
\frac{1}{R_o} = \frac{1}{R_{sh}} + \frac{1}{F \cdot R_w} \tag{3.1}
\]

where \( R_{sh} \) is the resistivity of shale. Although equation (3.1) lacks theoretical foundations, for the first time it considered the effect of clay minerals on the electrical properties of rocks and indicated the limitations of Archie equations.

Following the work of Patnode and Wyllie, De Witte (1950) established a different empirical two element model as follows:

\[
C_o = \frac{1}{F}[(1 - X_w)C_s + X_wC_w] \tag{3.2}
\]

where \( X_w \) is the volumetric fraction of saline water in the pore space. Since the so-called solid conductivity in the pore space \( (C_s) \) was assumed constant, the above model may be simplified as follows:

\[
C_o = A + BC_w \tag{3.3}
\]

where \( A \) and \( B \) are empirical constants related to the conductivity and volume fraction of clay. Therefore equation (3.3) suffers the same deficiency as equation
(3.1), i.e. it can only describes the linear portion of the $C_o$ vs $C_w$ plot.

Winsauer and McCardell (1953) further studied the mechanism of the abnormal conduction in shaley sands. An ionic double layer theory, instead of "conductive solids", was proposed to account for the clay effects. Their shaley sand interpretation model is as follows:

$$C_o = \frac{1}{F}(C_{dt} + C_w)$$

(3.4)

where $C_{dt}$ is the conductivity caused by the "electric double layer", which depends on (a) mobility (i.e. type) of positive ions in the double layer, and (b) difference in number of positive and negative ions in the double layer. This theory formed a base for numerous later models such as the W-S and D-W, which will be described later in detail. According to the authors, the abnormal conductivity of shaley sands and limes is a consequence of adsorption of ions on the clay surface and a resultant concentration of ions adjacent to the surface. The magnitude of the excess double layer conductivity varies with the concentration of the electrolyte.

Wyllie and Southwick (1954) conducted an experimental investigation on the effects of ion-exchange materials on the electrical properties of natural and synthetic porous materials. They concluded that as the amount of ion-exchange material decreases, the intercept of the straight line portion of the $C_o$ vs. $C_w$ plot also decreases. In addition, it was observed that the slope of the $C_o$ vs. $C_w$ plot at low salinities varies with the amount of conductive materials. Since two element models failed to describe the non-linear part of the $C_o$ vs. $C_w$ plot, Wyllie and Southwick introduced a three element model, (two in parallel and then in series with the third), given as follows:

$$C_o = \frac{C_s C_w}{x C_s + y C_w} + \frac{C_w}{F} + \frac{C_s}{z}$$

(3.5)

where $x$ and $y$ are geometric factors describing the arrangement of conductive solids and interstitial water; $z$ is the dimensionless geometric factor for the conductive solids. Since the interactive term is capable of modelling the curvature exhibited at low salinities, this model could be used to represent both the linear and non-linear portions of the $C_o$ vs. $C_w$ plot and to fit the experimental data more closely.
However, because of the difficulties in defining precisely these geometric factors, no attempt has been made to develop this equation further (Bussian 1983).

After extensive laboratory studies on electrical resistivity of shaley sands at room conditions, Hill and Milburn (1956) developed an empirical equation which relates the formation resistivity factor to the resistivity of the solution as shown in the following form:

\[ F = F_{0.01} \cdot (R_w)^{b \cdot \log(R_w)} \]  

(3.6)

where \( F_{0.01} \) is the formation resistivity factor which corresponds to a hypothetical equilibrating solution resistivity of 0.01 \( \text{ohm.m} \) at 25 °C when clay effects are presumed minimised, and \( b \) is a function of the clay content of the rock. This model earned its popularity in the early time due to the good agreement with the experimental data of a variety of shaley cores although it is purely empirical. There are two important contributions by Hill and Milburn to the more advanced later development in shaley models. First contribution is the statement that both the electrochemical and conductive behaviour of shaley sands are strongly related to the cation exchange capacity (CEC) per unit pore volume of rock. Second contribution is the introduction of the now well-known concept that formation resistivity factor changes with both shaliness and solution conductivity (\( C_w \)).

All the empirical shaley sand interpretation equations reviewed so far are for the fully water saturated formations. For the hydrocarbon bearing sands, the equations are the same as equation (2.11) except that the \( R_o (\frac{1}{C_w}) \) term is replaced by various shaley sand \( C_o \) formulas.

Despite the considerable efforts given to the shaley-sand problem during the 1950’s, the models described above collectively suffered from one fundamental drawback - in no case could the shale related parameter be determined directly from logging data (Worthington 1985). Beginning from the early 1960’s, therefore, attention was focused on the search for a model which did not suffer from as many shortcomings as in many previous models. The evolution of modern shaley sand concepts has produced two well defined types of models: the \( V_{sh} \) models based on the shale volume fraction and the cation-exchange or “double layer” models. A brief review of the \( V_{sh} \) models will follow, while the double layer models will be
reviewed in detail later in this chapter.

3.5 $V_{sh}$ Shaley Sand Models

The shale volume fraction, $V_{sh}$, is defined as the volume of wet shale per unit volume of reservoir rock. This definition takes into consideration the volume of chemically bound waters. An excellent review of the $V_{sh}$ models have been recently presented by Worthington (1985). Table 3.4 lists these models in chronological order for both water bearing shaley sands and hydrocarbon and water bearing shaley sands.

Table 3.4 $V_{sh}$ Models (After Worthington 1985)

<table>
<thead>
<tr>
<th>Models for Water Zone</th>
<th>Models for Hydrocarbon Zone</th>
<th>Authors</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_o = \frac{G_{f}}{F} + V_{sh}^{2}C_{sh}$</td>
<td>$C_t = \frac{G_{f}}{F} S_{w}^{c} + V_{sh}^{2}C_{sh}$</td>
<td>Hossin(1962)</td>
</tr>
<tr>
<td>$C_o = \frac{G_{f}}{F} + V_{sh}C_{sh}$</td>
<td>$C_t = \frac{G_{f}}{F} S_{w}^{c} + V_{sh}C_{sh}$</td>
<td>Simandoux(1963)</td>
</tr>
<tr>
<td>$\sqrt{C_o} = \sqrt{\frac{G_{f}}{F} + V_{sh}\sqrt{C_{sh}}}$</td>
<td>$\sqrt{C_t} = \sqrt{\frac{G_{f}}{F} S_{w}^{c} + V_{sh}\sqrt{C_{sh}}}$</td>
<td>Doll(unpublished)</td>
</tr>
<tr>
<td>$\sqrt{C_o} = \sqrt{\frac{G_{f}}{F} + V_{sh}^{2} \frac{F}{V_{sh}} \sqrt{C_{sh}}}$</td>
<td>$\sqrt{C_t} = \sqrt{\frac{G_{f}}{F} S_{w}^{c} + V_{sh}^{1 - \frac{3}{2a}} \sqrt{C_{sh}S_{w}^{3}}}$</td>
<td>Poupon and Leveaux(1971)</td>
</tr>
</tbody>
</table>

In Table 3.4 $C_{sh}$ is the wet clay conductivity which varies with both the shaliness and brine conductivity. The field application of $V_{sh}$ models requires the estimation of $V_{sh}$ at each designed level using the so-called shale indicators. A shale indicator is simply a conventional log or log combination whose response equations can incorporate a shale fraction term. Although the $V_{sh}$ models have continued to retain an important role in formation evaluation, they have often been misused due to the complex nature of the clay composition, mode of distribution and surface geometry in reservoir rocks.
As described earlier, the surface of clay minerals carries excess negative charges as a result of the substitution of certain positive elements by others of lower valence. When the clays are brought in contact with an electrolyte, these negative charges on the clay surface attract positive ions and repulse negative ions present in the solution. As a result, an electrical ionic double layer is generated on the exterior surface of clays. The accumulation of ions near the charged surface makes a contribution to the total solution conductivity and this may be called the surface conductance. According to the classic double layer models, the electrical double layer essentially consists of two regions between the solid surface and the bulk of the solution. These regions are called a “Stern layer” adjacent to the solid surface and a “Gouy diffuse layer” between the Stern layer and the bulk water.

3.6.1 The Gouy and Stern Concepts

As shown in Fig.3.3, an ionic atmosphere is created near the clay surface with the negative potential decreasing from maximum at the clay particle surface to zero at a distance $X_d$ (Robinson and Stokes 1959, Robbins 1972). Because this diffuse nature of the ionic atmosphere in the double layer was first explained in the Gouy theory, it is often referred as Gouy layer or simply diffuse layer.

The Gouy theory allows the calculation of the distribution of both positive and negative ions in the diffuse layer. The average electric potential at any point inside the diffuse layer can also be determined. The distribution of charges, according to this theory, depends on the concentration of the equilibrating electrolyte, the nature of the surface potential and the character of the surface charge. As the concentration of the bulk solution or the valence of the counterions increases, the thickness of the diffuse layer decreases.

There are some assumptions in the Gouy theory which limit its practical application. For instance, the ions are considered as mathematical point charges without actual sizes. Possible interactions between the counterions, the charged surface and the electrolyte are also neglected.

The Stern theory suggests that the approach of the counterions towards the charged surface is limited by a distance equivalent to the size of these ions. As
Fig. 3.3 Gouy’s diffuse layer model.
\( \sigma_1 \) - Net counterion charge of Stern layer
\( \sigma_2 \) - Net counterion charge of diffuse layer
\( \sigma \) - Total charge = \( \sigma_1 + \sigma_2 \)

Fig. 3.4 Stern's electrical double layer model.
illustrated schematically in Fig.3.4, a Stern layer of thickness $\delta$, which carries a fraction of the total charges, exists between the clay surface and a plane passing through the center of the closest ions. Beyond the Stern layer, there is a diffuse layer with almost identical properties as described by the Gouy model. It is predicted that the outer diffuse layer is compressed as the electrolyte concentration increases. Also, most importantly, this theory suggests that an increase in solution concentration forces counterions in the outer layer move towards the inner Stern layer. As a result, the equivalent counterion conductivity, or the surface conductivity, also changes as the diffuse layer expands as a function of the bulk water concentration.

### 3.6.2 The Waxman-Smits Model

Waxman and Smits (1968) used a simple physical model, consisting of two resistances in parallel, in order to develop an equation relating the electrical conductivity and the cation exchange capacity (CEC) per unit pore volume of rock. Their generalised equation (W-S) for water saturated shaley sands is as follows:

\[
C_o = \frac{1}{F^*}(B Q_v + C_w)
\]

and

\[
B = [1 - a \cdot exp(-\frac{C_w}{\gamma})]0.001\lambda^e_{Na}
\]

where

- $C_o$ = specific conductance of sand, 100% saturated with brine solution,
- $F^*$ = formation resistivity factor for shaley sand,
- $Q_v$ = volume concentration of clay exchange cations,
- $C_w$ = specific conductance of aqueous electrolyte solution,
- $a$ = dimensionless constant,
- $\gamma$ = constant,
- $\lambda^e_{Na}$ = maximum equivalent ionic conductance of sodium exchange cations associated with clay at 25 °C.

For a hydrocarbon zone, Waxman and Thomas (1974) assumed that the exchange cations associated with the clay become more concentrated in the remaining pore water and, therefore, proposed a conductivity equation as follows:
where $n^*$ is the W-S shaley saturation exponent. The W-S model was tested against the data given by Hill and Milburn (1950) and Waxman and Smits's experimental results on a wide variety of core samples and proved to be acceptable for analysing a wide range of shaley rock samples because of the simplicity and the relatively sound theoretical basis. In the absence of core data, Juhász (1981) proposed obtaining $Q_v$ from the "dry clay fraction," a parameter which can be determined using the neutron and density log responses.

### 3.6.3 The Dual-Water Model

Clavier et al. (1977) constructed a dual-water conductivity model (D-W) starting with the same over-simplified assumptions as in the W-S model but introducing the Gouy double-layer theory, in order to account for the so-called "clay-water" effect observed in experiment. The D-W model for a water-bearing shaley sand is given as follows:

$$C_o = \frac{1}{F_o} [(1 - \alpha v_Q Q_v)C_w + \beta Q_v]$$

(3.9)

where

- $F_o =$ formation factor for shaley sand as used in D-W model,
- $\alpha =$ expansion factor for diffuse layer,
- $v_Q =$ constant relating to the volume of salt-free water,
- $\beta =$ equivalent conductivity of sodium counterions.

For water-wet rocks, Clavier et al. observed that the hydrocarbons are kept in the central part of the pores by interfacial tension. They, therefore, assumed that the hydrocarbons displace the bulk water first. The equation for hydrocarbon zones before the clay-water is displaced can be expressed as follows:

$$C_t = \frac{S_w^{w'-1}}{F_o} [(S_w - \alpha v_Q Q_v)C_w + \beta Q_v]$$

(3.10)
where $S_w$ is the water saturation and $n'$ is the D-W shaley saturation exponent. Although this model is theoretically more advanced compared with the W-S model, it fits the experimental data with nearly the same accuracy as the latter because after all both models are based on the same over-simplified assumptions, i.e., two conductors (bulk solution and clay bound water) are in parallel with the same tortuosity. Clavier et al. (1984) reported the latest version of D-W model after improving the estimation of all the empirical constants $\alpha$, $\beta$ and $v_Q$. This new version will be used later in this thesis to model the experimental results.

### 3.6.4 Other Shaley Sand Models

Silva and Bassiouni (1985) developed a shaley sand conductivity model (S-B) based on the variable equivalent counter-ion conductivity and dual water concepts. The S-B equation for a water-bearing shaley sand at 25 °C is as follows:

$$C_{wspd} = \frac{C_{wec}}{F_e} = \frac{1}{F_e} [C_{eq}^+ Q_v + (1 - \nu_{DL}) C_w]$$  \hspace{1cm} (3.11)

where

- $C_{wspd} =$ conductivity of water-bearing shaley sand,
- $C_{wec} =$ effective conductivity of formation water,
- $F_e =$ formation factor of an equivalent water-bearing clean sand,
- $C_{eq}^+ =$ equivalent clay counter-ion conductivity,
- $Q_v =$ electrically effective counter-ion concentration expressed in terms of total PV,
- $\nu_{DL} =$ fractional volume under the influence of the electrical double layer, and
- $C_w =$ conductivity of free formation water.

The S-B model has not yet been extended to cover the hydrocarbon bearing sands. But the derivation of the equation is rather simple if the same assumptions as in the D-W model are made here. Although the S-B model originates from the D-W model, it is based on both the Gouy and the Stern models, and considers the changes of the equivalent counter-ion conductivity as the double layer expands, or in other words, as the temperature or the conductivity of the far water changes.

Recently, Sen and his co-authors (Sen 1987, Johnson and Sen 1988, Schwartz and Sen 1988) have developed a new theory of shaley sand conductivity, to ac-
count for the difference in the tortuosities of the bulk and surface conductance. The shaley sand is modelled by a three dimensional periodic array of charged overlapping spherical grains suspended in an electrolyte solution. The shaley sand conductivity \(C_o\) is solved numerically as a function of rock porosity \(\phi\), brine salinity \(C_w\), charge density \(Q_v\), and water saturation \(S_w\). Good agreement, according to the above authors, between some experimental results and the modelling results has been achieved. The use of the new model for both water and hydrocarbon zones requires the estimation of three empirical geometrical parameters. Although no firm conclusion can be drawn at this stage about this so-called grain consolidation model because a thorough comparison with previous models and, more importantly, with experimental data is still not available, the new model does seem to provide a different approach towards the complex problem of shaley sand conductivity.

There are also some models dealing specifically with hydrocarbon bearing shaley sands (Worthington et al. 1989, Argaud et al. 1989). Details are not included in this review since we are concentrating more on the cases where shaley sands are fully water saturated.

3.7 Discussion and Summary

There are over 30 different shaley sand interpretation models available in the literature, none of which, however, can be accepted for shaley sand conductivity interpretation without careful calibration based on some reliable experimental data. These early empirical interpretation techniques proposed in the 1950’s are no longer being used in the industry mainly due to the poor theoretical basis. Nevertheless, they all contributed to the understanding of the complex problem of shaley sand conductive behaviour in many different ways, especially the work by Winsauer and McCardell (1953) which formed a basis for the exciting late development of a group of double layer models such as the W-S and D-W. The \(V_{sh}\) models developed in the 1960’s are still being used in the industry mainly due to their apparent advantages of direct application in well logging. As reviewed earlier, however, these \(V_{sh}\) models are scientifically inexact and, therefore, often misused, leading to erroneous interpretations of shaley sand conductivities.

The W-S model (1968), which assumed a variable counterion conductivity in parallel with the electrolyte conductivity, became the first popular double layer
model. Clavier et al. (1977, 1984) offered an extension to the W-S model by accounting for the "clay water" effect based on the Gouy diffuse layer theory. Later on Silva and Bassiouni (1985) combined the features of the above two models and established a new model (S-B). Recently Sen (1987) and his co-authors developed a new shaley conductivity model which considers the difference in the tortuosity of both clay-water and bulk water conductions. These latest shaley models (Silva and Bassiouni 1985 and Sen 1987) which cover more physics, however, have not been tested against enough experimental data. Thus no firm conclusion can be drawn about their practical use.

Following the evolution of the double layer models, it is clear that a better understanding of the mechanism of shaley sand conductivity has been achieved as many new models were developed. These model's practical applications are sometimes disappointing contrary to their relatively sound theoretical foundation due to the following reasons: (a) empirical correlations of $Q_n$ or some related quantity with a log-derivable parameter are needed before these models can be used, (b) these existing models do not represent all the prevailing mechanisms of the conductive behaviour of shaley sands.

This study aims to investigate both experimentally and numerically the effect of clay on the electrical properties of shaley sands at reservoir conditions and, therefore, to enhance the predictive capacity of some significant shaley sand models. A comparison of some significant shaley sand conductivity models based on the experimental data of this study is given in Chapter 6. In particular, the W-S and D-W, which have become the industrial standards, are studied and treated in order to cover the effect of temperature and clay distribution on shaley sand conductivity.

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CHAPTER 4

EXPERIMENTAL APPARATUS AND PROCEDURE
4.1 Introduction

In Chapter 2, it has been concluded that a comprehensive experimental data base covering a wide range of rock types is necessary in order to predict the petrophysical properties of given reservoir rocks at elevated pressures and temperatures. Results based on a few samples may reveal some aspects of the mechanisms for the particular rock types tested, but not any general conclusions about the complex subject. So far there isn't enough experimental data available in the literature mainly due to the experimental limitations in the past and the well-known disadvantages of time-consuming in high pressure and temperature rock testing experiments.

At the initial stage of this research a single sample high pressure and temperature rock testing rig with an automatic data acquisition system was developed for the measurements of resistivity, permeability and pore volume deformation of core plugs at reservoir conditions. Preliminary testing with this single sample set-up required excessive times, sometimes up to two months, to test only one sample and most of the time was spent waiting for establishment of stress and thermal equilibria after each change of pressure and temperature. To overcome this problem, a novel multi-sample rock testing system was designed in collaboration with ITR (Lombos 1989). The use of this multi-sample system enables increase in the speed of testing and, since all the samples can be placed in identical conditions, elimination of any experimental comparison errors caused by the fluctuations of pressure created by an intensifier and temperature set by an oven.

This chapter outlines the multi-sample high pressure and temperature rock testing system and the experimental procedures for testing the electrical properties of core plugs at simulated reservoir conditions.

4.2 Multi-sample Rock Testing Apparatus

An experimental apparatus has been designed and constructed for Imperial College by ITR Ltd to measure the formation resistivity factor (F) and formation resistivity index (I) at elevated pressure and temperature and it is depicted schematically in Fig.4.1.(a). It is a multi-sample rock testing system in which a
maximum of five rock samples can be subjected to a variable thermostatic formation temperature, a variable hydrostatic confining pressure and an independently controllable pore pressure, to enable both hydraulic and electrical measurements. Fig.4.1.(b) shows the picture of the experimental rig.

This experimental system can be divided into four main sub-systems as follows:

4.2.1 The Pressure Vessel

The high temperature and pressure vessel used as shown in the left part of Fig.4.1 is tested to withstand pressures of up to 69 MPa (10,000 psi) at a maximum temperature of 175 °C. It permits flow of fluids or electrical current through all five core samples simultaneously. The five fluids inlet ports and five drain ports also serve as current electrodes which are insulated from the top and bottom end closures respectively. Special high pressure electrical feedthroughs are used for connecting the potential electrodes to the outside of the pressure vessel. The pressure vessel is mounted on a frame in the oven which may be heated to a temperature of 250 °C, with a temperature control inside ± 0.2 °C.

Inside the cell there are five cores each enclosed in a viton sleeve through which electrical measurements can be made via six electrodes. The reasons for using the multi-electrode sleeve are to ensure that two of these electrodes providing the best contacts with the sample are chosen for data collection and to determine the saturation distribution when two fluids are introduced in the core during any study of resistivity index and capillary pressure at reservoir conditions.

4.2.2 Hydraulic Circuits

There are two separated hydraulic circuits in the system. One is used to supply a hydrostatic confining pressure to the rock samples. Another is used to supply a constant pore pressure to all the samples and also to record the pore volume deformations due to changes of confining pressure and temperature. The details of these two hydraulic systems are as follows:
4.1.(a) Schematic diagram of the multi-sample system for measuring the electrical properties of rock samples at reservoir conditions.
4.1.(b) Picture of the multi-sample rig.
(a) Confining Pressure System

The confining pressure environment is created using an air-oil hydraulic pressure intensifier which has a maximum output oil pressure of 34.5 MPa (5000 psi). As shown in Fig.4.1, the intensifier is driven by the nitrogen gas from a gas bottle. The stability of the confining pressure supplied from the intensifier depends on the degree of the temperature control in the oven.

(b) Pore Pressure System

The two interface units as shown in the centre of Fig.4.1 are used to measure pore volume changes and to control pore pressure. A maximum of 2.4 MPa (350 psi) of pore pressure can be supplied at room temperatures. These five glass burettes inside the oil/brine interface unit are enclosed in a stress free annealed perspex tube and the assembly is held rigid between two aluminium end pieces. The perspex tube is sealed against the aluminium end piece using “O” ring seal. These calibrated glass tubes inside the oil/brine unit are partially filled with oil and partially filled with brine. In the gas/oil unit, the upper part is nitrogen gas which enters through the top end piece from a gas bottle. The lower part is filled with oil which is connected to the oil/brine unit below. A pressure regulator is connected in the gas line to regulate the pore pressure as required. To record the pore pressure a transducer is positioned between the regulator and the gas/oil interface unit. The pore pressure measurement is accurate to within ±0.0035 MPa (0.5 psi). And the pore volume changes can be measured with an accuracy of within 0.01 cc.

4.2.3 Electrical Circuit

The electrical connection is based on the principle of four-wire resistivity measurement (Rust 1952) as shown in Fig.4.2 to eliminate the errors caused by the electrode reaction and the contact resistance. Although there isn’t any significant difference among the readings taken at various low frequencies, the electrical resistances of some samples have been measured using an AC resistance technique at four frequencies for comparison (i.e. 200 Hz, 500 Hz, 2 KHz and 10 KHz). For consistency, the experimental results to be presented in this thesis are all measured
at 2 KHz. The AC voltages across both the known resistance and the sample are compared to calculate the resistance of the sample using the following simple equation:

\[ R_{(sample)} = \frac{V_{(sample)}}{V_{(resistor)}} \cdot R_{(resistor)} \]  

(4.1)

![Schematic diagram of the 4-wire resistivity measurement](image)

Fig. 4.2 Schematic diagram of the 4-wire resistivity measurement

### 4.2.4 Automatic Data Acquisition System

Recording manually all the experimental data including confining pressure, pore pressure, temperatures, deformations and voltages across both the precision resistor and across five intervals of each rock sample, from the multi-sample rock testing rig is highly time-consuming. Also the conditions of pressure and temperature may vary during the period of data recording, which reduces the accuracy of the experiments. Therefore, establishing an automatic data acquisition system became necessary.

The automatic data acquisition is achieved by employing a resistivity unit which generates the AC current with required frequency and convert the AC signals into DC signals and a data bus which transfers experimental data to a microcomputer. A switch box is used to connect each core with the data recording
system. Two pressure transducers are used to record the confining pressures and pore pressures. Both the formation temperature and room temperature are measured with two platinum resistance probes. Finally a multi-recorder is used to monitor the pressure and temperature deviations continuously.

The resistivity unit generates 0 - 10 volt AC current with a frequency range from 20 Hz to 20 KHz. It has three core resistance settings, namely small, medium and large, which can be set to measure cores with three resistance ranges (i.e. < 10 ohms, 10 - 1000 ohms and > 1000 ohms) in order to obtain maximum resolutions of the resistivity readings.

The converter interface has the standard connector of the IEEE-488 bus mounted on the back-panel of the interface. This 16 line bus is used to interconnect up to 15 separate devices each connected in parallel to the bus. There are 6 modules for recording the voltages across the precision resistor and across the five intervals of the core, 2 modules for measuring both the confining pressure and pore pressure and a module for reading both the oven and room temperatures. The calibration of these voltage and pressure recording units is carried out using a constant DC current supply and a digital volts meter. The temperature unit is calibrated using a precision thermometer which has already been calibrated. A timer is used to set the time intervals for data collections. The steps involved in transferring experimental data to the computer are as follows:

a. Send out an address (an integer number) to select the data bus interface as a TALKER on the IEEE-488 bus.
b. Selecting the module to which the experimental apparatus is connected by sending a secondary address.
c. Set the HPIB to LISTEN so that it can receive data from the bus.
d. Enter the data placed on the data bus through the HPIB interface and into the computer.
e. Terminate the TALK function and restore the HPIB.

4.3 Design of Experimental Programme

Fourteen different clean (clay-free) sandstone rock samples have been chosen to measure their electrical properties at elevated pressures and temperatures. Five clean sandstone samples and 7 synthetic shaley samples are used to study the effect
of pressure, temperature and clay on the absolute permeability of rocks. Finally in order to quantify the effect of clay on the electrical conductivities of shaley sands at both room and reservoir conditions, 14 synthetic shaley samples containing various type and amount of clays and with different clay distributions are prepared and tested. The detailed descriptions of these sandstone and synthetic samples are included in Appendix C and Chapter 6 respectively.

4.4 Experimental Procedure

The experimental procedure for measuring the electrical properties of natural sandstone rocks at elevated pressures and temperatures is described in the following sections.

4.4.1 Preparation of Rock Samples and Brine Solutions

(a) Preparation of Rock Samples

The natural rock samples used for experimental measurements are thoroughly cleaned to remove dirt which may be present in the pores. A method similar to the Soxhlet refluxing solvent extraction technique (Pirson 1958) is applied by flushing methanol through the rock sample. This refluxing process is carried out overnight and in some cases longer until the colour of the output fluids remains the same, indicating that no further residue inside the core can be washed out.

Rock samples are first cut into cylinders with 1.5” in diameter using a diamond core drill, and then cut into 3” long plugs with a diamond impregnated cutting wheel mounted on the tool-post grinder of a lathe. Ten percent NaCl solution is used as the bit coolant. For good contacts between the rock sample and the current electrodes, both core ends are made parallel.

The geological description of rock samples is given by thin section analysis. The sample porosity and grain density are determined using a helium gas expansion volume meter. Permeability measurements at room conditions are taken using a Hassler cell with air as the flowing medium. Some samples are chosen to measure rock pore size distributions using a mercury injection technique. The detail of
the apparatus and procedure for the porosity, permeability and capillary pressure measurements is described in Appendix B.

Core samples are dried for over 24 hours at 70 °C in an oven to remove any moisture from the pores. The dimensions are then measured precisely with callipers to determine the bulk volume, and the cores are weighed. Before being placed in the high temperature and pressure vessel for testing, the core plugs are fully saturated with the brine solution. This is accomplished using a saturator as shown in Fig. 4.3. Core samples are placed in a pressure vessel under a vacuum for about 12 hours in order to remove air from the pores. The brine inlet valve is then opened, which allows the de-aerated brine solution to enter the chamber, until the cores are completely submerged. Finally, an air-hydraulic pump is used to create a pressure of about 13.8 MPa (2000 psi) inside the chamber to force brine solution into very small pores. The samples are removed after 12 hours, at which point they are weighed. The porosities are then calculated from the difference between the dry weight and the wet weight. The difference of porosity obtained from this technique and the helium expansion method is generally less than 0.5% pore volume.

The procedure for preparing and saturating synthetic shaley samples will be described in Chapter 6.

(b) Preparation of Brine Solutions

Brine solutions of different concentrations are made up of NaCl and, de-aerated and de-ionised distilled water. At least 48 hours are required for the coarse particles to dissolve completely in the water and the solution to reach equilibrium. The solution resistivities ($R_w$), which vary as a function of solution temperature, are measured with a digital conductivity meter. Very close agreement has been found between the solution resistivities measured and those calculated from the empirical equations given by Arps (1953) and some conductivity charts commonly used in the oil industry (e.g. Hilchie 1982).

Five different NaCl solutions, namely 120, 50, 20, 5 and 2 grams/litre, were selected. The solution resistivity data points measured were fitted by polynomial curves with an accuracy inside 0.1%. The solution resistivities ($R_w$) in ohm-meters changing as a function of temperature ($T$) in °F between 50 °F (10 °C) and 317
Vacuum pump

Vacuum port

Vacuum de-airing tank

Mercury vacustat

Air hydraulic pump

Pressure gauge

Relief valve

Core

Pressure vessel

Fig. 43 Schematic diagram of the ITR saturator.
\(^{\circ}F\) (175 \(^{\circ}C\)) are listed as follows:

1. C = 120 grams/litre

\[
R_w = 0.1633 - 1.854 \cdot 10^{-3}T + 1.000 \cdot 10^{-5}T^2 - 2.633 \cdot 10^{-8}T^3 + 2.693 \cdot 10^{-11}T^4
\]  
(4.2)

2. C = 50 grams/litre

\[
R_w = 0.3091 - 3.438 \cdot 10^{-3}T + 1.799 \cdot 10^{-5}T^2 - 4.525 \cdot 10^{-8}T^3 + 4.387 \cdot 10^{-11}T^4
\]  
(4.3)

3. C = 20 grams/litre

\[
R_w = 0.8084 - 1.079 \cdot 10^{-2}T + 6.717 \cdot 10^{-5}T^2 - 1.961 \cdot 10^{-7}T^3 + 2.163 \cdot 10^{-10}T^4
\]  
(4.4)

4. C = 5 grams/litre

\[
R_w = 2.661 - 3.138 \cdot 10^{-2}T + 1.766 \cdot 10^{-4}T^2 - 4.758 \cdot 10^{-7}T^3 + 4.910 \cdot 10^{-10}T^4
\]  
(4.5)

5. C = 2 grams/litre

\[
R_w = 6.717 - 8.221 \cdot 10^{-2}T + 4.673 \cdot 10^{-4}T^2 - 1.255 \cdot 10^{-6}T^3 + 1.285 \cdot 10^{-9}T^4
\]  
(4.6)

It must be stressed here that all five \(R_w\) equations listed above can be used only within the temperature range specified. Also the pressure dependence of solution conductivity is assumed to be negligible.

### 4.4.2 Resistivity Measurements at Reservoir Conditions

The first step in the measurements is the placement of the five core samples inside the Viton sleeves. To prevent air bubbles being trapped inside the core, the core is inserted into the sleeve under the brine solution. Two platens which also serve as current electrodes are inserted into the sleeve so that both ends of the core are tightly against the platens. The core holder is wrapped carefully and assembled onto the bottom end closure with the 1/8” flow tube passing smoothly
through the electrical feedthrough in the bottom end closure. The same procedure is repeated for the four remaining samples. Before the bottom end closure with all five core holders assembled on it is loaded into the pressure vessel, electrical connections of all the potential electrodes are made and electrical insulations of the current leads (flow tubes) are checked using a digital volts meter. After the bottom end closure is installed and fixed with a screwed ring, the vessel is filled with oil. The top end closure is then loaded with all the flow process tubes going through the feedthroughs. The electrical insulation of all the current and potential electrodes is finally checked, and both screwed rings are tighten. The oil from the pressure intensifier is pumped through the confining pressure lines to prevent any air bubbles being trapped inside. To remove any air bubbles trapped at the core ends, de-aerated brine is injected into the 1/16” tube inside the 1/8” tube while the annular space between the two tubes provides the drainage port. The five pore fluid tubes are then connected to the oil/brine interface unit which is used to apply pore pressures and to measure the core deformations. An initial overburden pressure of about 1.7 MPa (250 psi) is applied to ensure that all the sleeves seal onto the core plugs and the platens. Before the automatic data acquisition system being connected, the electrical properties of all five rocks are measured manually for the comparison with the base line information obtained using a room condition 4-wire resistivity unit.

To ensure reliable experimental results of rock electrical properties, the calibration procedure for the multi-sample system is summarised as follows:

a. Check the electrical insulation of both current electrodes and all the potential electrodes,

b. Compare the reservoir condition resistivity with the base line reading collected using a room condition 4-wire resistivity unit,

c. Calculate the resistivity values measured among five different intervals on the same core, to prevent wrong resistivity readings due to the bad contact between the potential electrodes and the core sample,

d. When studying the effect of one variable such as confining pressure, fix all other variables including the pore pressure, the temperature and the current through the circuit to minimise the system error,

e. Calibrate the automatic data recording and processing system using the non-inductive precision resistors,

f. Study the stability (time effect) and reproducibility (hysteresis) of experimental data collected using the fully automatic data acquisition system. If
the calibration process is successful, experiments can proceed. Otherwise the
system needs to be dismantled and the electrical contact and insulation need
to be checked.

For each pressure and temperature, readings are taken when the brine level
in the calibrated glass burette stops rising and the voltages are stabilised. It takes
about 2 hours for the pressure to be stable and over night for the temperature to
be stable, with a pressure change of about 3.4 MPa (500 psi) and a temperature
variation of about 20°C. Some experiments were conducted to study the mechanical
relaxation effect by prolonging the time interval to more than 24 hours. For
the study of hysteresis, data are taken in both cycles. One such experiment in-
volves increasing pressure and temperature from lower limits, and another reduces
pressure and temperature from the upper limits.

In order to establish the effects of the excess conductivity of clay minerals (Co
vs. Cw plot) for the synthetic shaley samples, experiments have been carried out
to measure the electrical conductivities at various brine concentrations. This is
accomplished by flushing more than 20 pore volumes of de-aerated brine through
the core until no measurable changes in resistance (within known error limits) is
observed over a period of several hours. The details will be described in Chapter
6.

4.5 Error Analysis

The accuracy of measured formation resistivity factor (F) values at laboratory
conditions is influenced by errors in the individual measurements and also some
generally unrecognised deviations in the conditions of measurement (Worthington
1975). Table 4.1 summarises reasonably attainable errors in calculated formation
factor of 1" diameter cores from room condition measurements using a Hassler
type of resistivity cell. It is assumed that the following three sources of error are
eliminated: drainage of brine from surface, plastic impregnation of surface and
evaporation of water from surface.

It is indicated in Table 4.1 that although the mentioned sources of error may
cancel each other, the maximum error of the calculated formation factor may still
reach 10%. Therefore, unless greater attention is paid to the accuracy of individual measurements and the time dependent deviations, the investigation of the effects of pressure and temperature on formation factor may become impossible.

Although resistivity measurements at elevated pressure and temperature conditions have advantages such as eliminating drainage and evaporation of brine from core surface, minimising the effects of plastic impregnation and excess brine film conduction on the surface because of the confining pressure, new sources of error are introduced as a result of high pressure, temperature and the use of a resistivity cell which simulates reservoir conditions. In order to detect the changes of resistivity factor due to pressure and temperature, an improved calibration procedure has been developed. Table 4.2 illustrates the errors in the experiments of measuring formation resistivity factor at simulated reservoir conditions.

The values in Table 4.2 are derived using a simple computer program based on the experimental measurements on core plug S5 which is 1.5" in diameter and 3" in length. Most of the errors in resistivity measurements at reservoir conditions occurs in the temperature control and measurement and \( R_w \) measurement. It is also indicated by comparing Table 4.1 and 4.2, the errors due to the measurements of core length and diameter can be significantly reduced when larger core plugs are used. The maximum error occurring in the formation factor measurements at simulated reservoir conditions of pressure and temperature, calculated with an error analysis technique taking the differential of formation factor equation (\( F = f(L, D, P, T, R_w) \)) and knowing the error in each measurement, is less than 3%. For example the changes of formation resistivity factor for sample S5 with pressure varying from atmospheric to 30 MPa and temperature changing from ambient to 130 °C are 20% and 15% respectively, which are significant enough to be determined accurately by the experimental system used in this study.

The error analysis of permeability measurements at reservoir conditions will be given in Chapter 7.

4.6 Results of Rock Characterisation

Table 4.3 lists the results of core length (\( L \)) in cm, cross sectional area (\( A \)) in \( cm^2 \), grain density (\( \rho_g \)) in grams/cc, porosity (\( \phi \)) in % and Klinkenberg corrected
liquid permeability ($k_{\infty}$) in $mD$ for the 15 sandstone samples measured. The geological description of these rocks is included in Appendix C. The information of the synthetic shaley samples is listed in Chapter 6.

Table 4.1 Errors in the Laboratory Measurement of $F$
(after Worthington (1975))

<table>
<thead>
<tr>
<th>Nature of Error</th>
<th>Unit of Error</th>
<th>Error in Parameter</th>
<th>Error in $F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length Measurement</td>
<td>inches</td>
<td>±0.01</td>
<td>±1.0%</td>
</tr>
<tr>
<td>Diameter Measurement</td>
<td>inches</td>
<td>±0.005</td>
<td>±2.0%</td>
</tr>
<tr>
<td>Excess Brine Film</td>
<td>inches</td>
<td>$10^{-4}$</td>
<td>-3.9%</td>
</tr>
<tr>
<td>Bevelled Edge on Core</td>
<td>inches</td>
<td>+0.05</td>
<td>+1.2%</td>
</tr>
<tr>
<td>Resistivity Measurement</td>
<td>%</td>
<td>±1.0</td>
<td>±1.0%</td>
</tr>
<tr>
<td>$R_w$ Measurement</td>
<td>%</td>
<td>±1.0</td>
<td>±1.0%</td>
</tr>
<tr>
<td>Temperature Measurement</td>
<td>°C</td>
<td>±0.2</td>
<td>±0.2%</td>
</tr>
</tbody>
</table>

Table 4.2 Errors in the Measurements of $F$ at Simulated Reservoir Conditions

<table>
<thead>
<tr>
<th>Nature of Error</th>
<th>Unit of Error</th>
<th>Error in Parameter</th>
<th>Error in $F$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length Measurement</td>
<td>cms</td>
<td>±0.005</td>
<td>±0.1%</td>
</tr>
<tr>
<td>Diameter Measurement</td>
<td>cms</td>
<td>±0.005</td>
<td>±0.3%</td>
</tr>
<tr>
<td>Geometry after Deformation*</td>
<td>cms</td>
<td>±0.005</td>
<td>±0.1%</td>
</tr>
<tr>
<td>Pressure Measurement</td>
<td>psi</td>
<td>±10.0</td>
<td>±0.2%</td>
</tr>
<tr>
<td>Temperature Measurement</td>
<td>°C</td>
<td>±0.5</td>
<td>±0.5%</td>
</tr>
<tr>
<td>$R_w$ Measurement</td>
<td>%</td>
<td>±1.0</td>
<td>±1.0%</td>
</tr>
<tr>
<td>Data Recording and Processing</td>
<td>%</td>
<td>±0.2</td>
<td>±0.2%</td>
</tr>
</tbody>
</table>

* - error in estimating the true size of cores after deformation
Table 4.3 List of Sandstone Samples for Resistivity Test

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Block No.</th>
<th>Rock Type</th>
<th>( L )</th>
<th>( A )</th>
<th>( \rho_d )</th>
<th>( \phi )</th>
<th>( k_{\infty} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>16-5B</td>
<td>Sandstone</td>
<td>7.615</td>
<td>11.116</td>
<td>2.634</td>
<td>13.30</td>
<td>9.83</td>
</tr>
<tr>
<td>S2</td>
<td>15-8C</td>
<td>Sandstone</td>
<td>7.670</td>
<td>11.187</td>
<td>2.651</td>
<td>23.07</td>
<td>3481.93</td>
</tr>
<tr>
<td>S3</td>
<td>17-4B</td>
<td>Sandstone</td>
<td>7.750</td>
<td>11.092</td>
<td>2.645</td>
<td>16.67</td>
<td>8.34</td>
</tr>
<tr>
<td>S4</td>
<td>19'-2C</td>
<td>Sandstone</td>
<td>7.608</td>
<td>11.151</td>
<td>2.641</td>
<td>22.10</td>
<td>873.39</td>
</tr>
<tr>
<td>S5</td>
<td>18-2C</td>
<td>Sandstone</td>
<td>7.640</td>
<td>11.377</td>
<td>2.639</td>
<td>14.25</td>
<td>74.11</td>
</tr>
<tr>
<td>S6</td>
<td>18-2A</td>
<td>Sandstone</td>
<td>7.638</td>
<td>11.365</td>
<td>2.638</td>
<td>14.18</td>
<td>70.63</td>
</tr>
<tr>
<td>S7</td>
<td>19'-2A</td>
<td>Sandstone</td>
<td>7.726</td>
<td>11.074</td>
<td>2.599</td>
<td>20.42</td>
<td>711.24</td>
</tr>
<tr>
<td>S8</td>
<td>17-4C</td>
<td>Sandstone</td>
<td>7.782</td>
<td>11.068</td>
<td>2.645</td>
<td>16.46</td>
<td>8.78</td>
</tr>
<tr>
<td>S10</td>
<td>17-4A</td>
<td>Sandstone</td>
<td>7.740</td>
<td>11.080</td>
<td>2.644</td>
<td>15.70</td>
<td>6.00</td>
</tr>
<tr>
<td>S11</td>
<td>16-5A</td>
<td>Sandstone</td>
<td>7.618</td>
<td>11.116</td>
<td>2.623</td>
<td>12.81</td>
<td>6.70</td>
</tr>
<tr>
<td>S12</td>
<td>16-5B</td>
<td>Sandstone</td>
<td>7.617</td>
<td>11.118</td>
<td>2.623</td>
<td>13.11</td>
<td>7.86</td>
</tr>
<tr>
<td>S13</td>
<td>15-8A</td>
<td>Sandstone</td>
<td>7.656</td>
<td>11.127</td>
<td>2.651</td>
<td>22.18</td>
<td>3132.42</td>
</tr>
<tr>
<td>S14</td>
<td>15-8B</td>
<td>Sandstone</td>
<td>7.655</td>
<td>11.145</td>
<td>2.652</td>
<td>22.36</td>
<td>2893.56</td>
</tr>
<tr>
<td>S15</td>
<td>19'-2B</td>
<td>Sandstone</td>
<td>7.686</td>
<td>11.139</td>
<td>2.641</td>
<td>22.43</td>
<td>837.21</td>
</tr>
</tbody>
</table>

References


Worthington, A.E. Errors in the laboratory measurement of formation resistivity factor. *SPWLA Sixteenth Annual Logging Symposium*, (June 4-7, 1975), paper D.
CHAPTER 5

THE EFFECT OF PRESSURE AND TEMPERATURE ON
THE ELECTRICAL PROPERTIES OF SANDSTONE ROCKS
5.1 Introduction

In Chapter 4, the multi-sample rock testing apparatus and the experimental procedures for measuring the electrical properties of core plugs at simulated reservoir conditions have been described. Using the apparatus, experiments have been carried out on 15 different outcrop sandstone samples. The mineral composition of these rock samples identified by thin section analysis is described in Appendix C.

This chapter presents the experimental results of electrical resistivity measurements on the sandstone samples at simulated reservoir conditions of pressure and temperature. Interpretations of both the individual effect and the combined effect of pressure and temperature on the formation resistivity factor (F) and the Archie cementation factor (m) are presented and discussed. Finally, a parametric study is provided to demonstrate the importance of the effect of pressure, temperature, and hysteresis on the estimation of the petrophysical properties of these sandstones.

5.2 The Effect of Confining Pressure

During the confining pressure tests, the rock resistance ($r_o$) and the rock deformation are measured with respect to net confining pressure which is defined as: confining pressure - pore pressure. Many previous researchers ignored the rock geometry changes during the calculation of the resistivity ($R_o = r_o F$) at high pressures which can induce considerable error in the formation resistivity factor and cementation factor calculations.

The deformation of rocks under confining pressures is considered in this study to calculate the rock resistivity ($R_o$) from the resistance using Ohm's Law. The following three simple equations, which have been derived based on the assumption that the rock samples are ideally elastic and isotropic, are used to calculate the total changes in bulk volume ($\Delta V$), length ($\Delta L$) and diameter ($\Delta D$) of these rocks:
\[ \Delta V = \frac{3(1-2\nu) \cdot P \cdot V}{E} \quad (5.1) \]

\[ \Delta L = \frac{4\Delta V}{3\pi D^2} \quad (5.2) \]

and

\[ \Delta D = \frac{4\Delta V}{3\pi \cdot D \cdot L} \quad (5.3) \]

where \( V, D \) and \( L \) are the initial bulk volume, diameter and length of rocks before loading, \( E \) and \( \nu \) are the Young's modulus and Poisson's ratio, and \( P \) is the hydrostatic confining pressure. Then the true cross-sectional area of the rock sample becomes:

\[ A = \frac{\pi}{4}(D - \Delta D)^2 \quad (5.4) \]

Since the measuring interval is fixed by the potential electrodes in the Viton sleeve, there is no need to modify the length.

5.2.1 Formation Factor versus Confining Pressure

Figs.5.1 - 5.6 show the effect of confining pressure on the normalised formation factor, which is defined as the \( F \) at elevated pressures over the base line values obtained at atmospheric pressure conditions, for 6 sandstone samples (S1, S2, S3, S4, S5 and S11). The general observations of this section are:

a. Normalised formation factor increases significantly with confining pressure over a range from 0 to 32 MPa. However, the rate of increase of \( F \) is generally greater in the lower pressure range (e.g. < 10 MPa) than in the higher pressure range. Also as shown comparatively by Fig.5.7 the pressure effect on \( F \) is greater for S1, S3 and S5 than that for S2 and S4 which are relatively more porous and more permeable.
b. Another interesting feature shown by Figs.5.1 - 5.7 is that the $F$ values in the unloading cycles are always higher than those measured in the loading cycles. Similar hysteresis effects have been obtained for all the other samples.

The reason for the increase of $F$ with pressure is simply because of the compression effect which reduces the pore sizes and changes the tortuosity of current flow paths (Fatt 1957, Brace et al. 1965, Brace and Orange 1968, Timur et al. 1972). The amount of increase in resistivity with pressure appears different for different rocks depending upon the porosity, permeability, pore size distribution, clay content and cementation. The more rapid increase of resistivity with pressure at lower pressures than at higher pressures can be explained because rocks are more compressible at lower confining pressures (i.e., the bulk modulus increases with pressure). This is due to the fact that rocks contain a spectrum of pores with various geometries. These pores with small aspect ratios are very pressure sensitive so that they deform significantly even at low pressures, while those pores with large aspect ratios do not deform with pressure significantly. As pressure increases, the $F$ may eventually become constant due to the closure of pores with small aspect ratios.

An explanation for the greater effect on $F$ in less porous, less permeable rocks was suggested by Glanville (1959) as these rocks have larger percentage of small pores which can be compressed more effectively than large capillaries. Xu et al. (1990) suggested that tight rocks usually have relatively large percentage of micro-cracks or pores with very small aspect ratios which are sensitive to pressure changes. Therefore, as a result of the relatively more dramatic pore geometry and size changes, the bulk pore constrictions of less porous and permeable rocks increase with confining pressure more significantly compared with that of more porous and permeable rocks (Jing et al. 1989). All the above observations of pressure effect on $F$ have been simulated numerically based on a pore space network model in order to achieve further understanding of the mechanisms. The details of the simulation will be described later in Chapter 8.

According to Fatt (1957), there was little or no difference between the data obtained during loading cycles and those measured during unloading cycles, if sufficient times were allowed for the equilibrium. However, this study shows significant hysteresis between the loading and unloading pressure cycles occurring even after long waiting time intervals up to 12 hours and after many loading and unloading cycles as illustrated by Fig.5.8. However, this hysteresis is generally
Fig. 5.1 Normalized $F$ vs. confining pressure for sample S1 at room temperatures ($F(0) = 40.75$).

Fig. 5.2 Normalized $F$ vs. confining pressure for sample S2 at room temperatures ($F(0) = 12.64$).
Fig. 5.3 Normalized $F$ vs. confining pressure for sample S3 at room temperatures ($F(0) = 39.50$).

Fig. 5.4 Normalized $F$ vs. confining pressure for sample S4 at room temperatures ($F(0) = 17.12$).
Fig. 5.5 Normalized $F$ vs. confining pressure for sample S5 at room temperatures ($F(0) = 51.13$).

Fig. 5.6 Normalized $F$ vs. confining pressure for sample S11 at room temperatures ($F(0) = 35.14$).
Fig. 5.7 Comparison of confining pressure effect on F for 5 sandstone samples at room temperatures.

Fig. 5.8 Normalized F vs. confining pressure for sample S11 at room temperatures showing the hysteresis effect.
Fig. 5.9 Cementation factor vs. confining pressure for sample S1 at room temperatures.

Fig. 5.10 Cementation factor vs. confining pressure for sample S2 at room temperatures.
Fig. 5.11 Cementation factor vs. confining pressure for sample S3 at room temperatures.

Fig. 5.12 Cementation factor vs. confining pressure for sample S4 at room temperatures.
reproduceable when these loading-unloading cycles are repeated. The hysteresis observed may be explained by the relaxation or the so-called time dependent rock elastic behaviour. For a given rock the hysteresis observed depends on the magnitude, the increment and the duration of confining pressure (Jaeger and Cook 1977).

5.2.2 Cementation Factor versus Confining Pressure

The experimental results of Archie cementation factor ($m$), which is calculated by $m = -\log F / \log \phi$ derived from equation (2.5), at various confining pressures for the 4 sandstones samples (S1, S2, S3 and S4) are shown in Figs.5.9 - 5.12. Before correction for changes in porosity caused by overburden pressure, i.e. ignoring the porosity change during the calculation of $m$ at various pressures, $m$ seems to increase dramatically with pressure for all the samples. After porosity correction, however, the $m$ changes resulting from increasing confining pressure become relatively smaller but still significant. As in the previous figures of $F$ at elevated pressures, there is also an obvious hysteresis occurring here between the $m$ values in the loading and unloading cycles for all the cores. The hysteresis observed for cementation factor at various pressures might be explained in the same way as in the plot of $F$ versus confining pressure mentioned previously.

Similar results of cementation factor at various pressures were reported by Fatt (1957) indicating that compression of the rock causes more radical changes in resistivity and permeability than does the change in porosity. It might be concluded based on the experimental results that the increase of resistivity with confining pressure not only results from the rock deformation but also from other sources such as changes of pore constrictions. The same conclusion can also be obtained by pore space network modelling which will be described later in this thesis.

5.3 The Effect of Temperature

In order to investigate the effect of temperature on the electrical properties of rocks, experimental results obtained from 6 sandstone cores, namely S1, S2, S3, S4, S5 and S6, are presented. The measured values of formation factor are
normalised using a base line value obtained at ambient temperatures as shown in Figs.5.13 - 5.18. It is clear from these figures that F increases significantly with temperature and is accompanied by an obvious hysteresis between the heating and cooling cycles over a range from 20 °C to 130 °C. However, the rate of increase is generally less significant in the lower temperature range (e.g. < 100 °C) than in the higher pressure range. The temperature effect on F varies among these sandstone samples as shown comparatively by Fig.5.19. A maximum increase of 28% and a minimum increase of 15% in F from ambient to 130 °C under a net confining pressure of 13.8 MPa were observed for core S1 and S5 respectively. Similar results of temperature effect on F have been obtained for all the other sandstone samples tested.

Figs.5.20 - 5.23 show the results of Archie cementation factor plotted before and after porosity corrections for 4 cores (S1 - S4) at various temperatures from ambient to 130 °C and under a constant confining pressure of 13.8 MPa. Since the external size of rock samples is assumed to be the same at various temperatures, when a confining pressure is applied, thermal expansion of rock forming materials leads to the reduction in the total pore spaces. This thermal induced porosity decrease has been measured using the two pore fluid interface units calibrated using dummy cores to account for thermal expansions of pore fluids at elevated temperatures.

The same hysteresis as observed in the plots of F versus temperature also manifests itself in the Archie cementation factor versus temperature curves. Similar changes in the slope of both F and m at various temperatures have been observed. The changing rate of both F and m is smaller in the lower temperature range (e.g. < 100 °C) than in the higher temperature range.

There are two particular factors influencing the electrical properties of reservoir rocks at elevated temperatures.

a. One is related to the thermal effects including thermal expansion and perhaps pore structure changes.

b. Another is the electrochemical effect associated with the clay minerals.

Theoretically, although the possible micro-cracks resulted from the heating and cooling process may reduce the rock resistivity, the thermal expansion of rock forming materials increases the rock resistivity (Hilchie 1964, Sanyal 1972, 1973, Brannan and Gonten 1973 and Ucok 1979, Mahmood et al. 1988).
Fig. 5.13 Normalized F vs. temperature for sample S1 under a confining pressure of 13.8 MPa ($F(0) = 45.62$).

Fig. 5.14 Normalized F vs. temperature for sample S2 under a confining pressure of 13.8 MPa ($F(0) = 12.86$).
Fig. 5.15 Normalized $F$ vs. temperature for sample S3 under a confining pressure of 13.8 MPa ($F(0) = 42.22$).

Fig. 5.16 Normalized $F$ vs. temperature for sample S4 under a confining pressure of 13.8 MPa ($F(0) = 17.73$).
Fig. 5.17 Normalized $F$ vs. temperature for sample S5 under a confining pressure of 13.8 MPa ($F(0) = 57.32$).

Fig. 5.18 Normalized $F$ vs. temperature for sample S6 under a confining pressure of 13.8 MPa ($F(0) = 48.49$).
Fig. 5.19 Comparison of temperature effect on F for 5 sandstone samples under a confining pressure of 13.8 MPa.
Fig. 5.20 Cementation factor vs. temperature for sample S1 under a net confining pressure of 13.8 MPa.

Fig. 5.21 Cementation factor vs. temperature for sample S2 under a net confining pressure of 13.8 MPa.
Fig. 5.22 Cementation factor vs. temperature for sample S3 under a net confining pressure of 13.8 MPa.

Fig. 5.23 Cementation factor vs. temperature for sample S4 under a net confining pressure of 13.8 MPa.
excess conductivity associated with clays, which changes with temperature, can reduce the total rock resistivity (Hill and Milburn 1956, Waxman and Smits 1968, Waxman and Thomas 1974, Kern et al. and Parkhomenko 1982). Therefore the total effect of temperature on $F$ depends on which particular factor or factors dominate in a given rock.

The effects of temperature on $F$ measured in these sandstone cores may only be related to thermal expansion and perhaps some permanent pore structure changes caused by heating and cooling, since all the samples have been treated at high temperatures so that the clay cation exchange capacity approaches zero. When a confining pressure is applied, thermal expansion of rock forming materials leads to the reduction of the pore spaces and microscopic changes in the internal pore geometries. As a result decreases in the porosity and changes of pore constrictions may happen at the core plug scale. The increase of $m$ with temperature further reveals that the reduction in rock porosity is not sufficient to cause the observed changes in $F$. The change of the pore space geometries and tortuosities at elevated temperatures, which lead to the change of the pore constrictions, also play an important role in the effect of temperature on rock resistivity.

The more dramatic increase in $F$ at relatively higher temperatures (e.g. > 100°C) may be due to the non-linear nature of the changes in pore constrictions due to thermal expansions of rock forming minerals and also some possible permanent pore structure collapses. The difference in the rate of change of $F$ against temperature among various rocks may be explained by the differences in the mineral compositions of these rocks as shown in Appendix C as well as the differences in pore shapes and pore size distributions.

It is interesting to note that the hysteresis which occurred in the temperature experiments for sample S2 and S4 is different from that for sample S1, S3, S5 and S6 as illustrated by Figs.5.13 - 5.18. All the $F$ and $m$ values measured during cooling cycles are greater than those measured during the heating cycles for S2 and S4, while the opposite has been observed for the other samples mentioned above. The hysteresis observed for sandstone S2 and S4 during the temperature experiments may be the result of (a) the similar relaxation effect or the time effect as mentioned previously in the pressure experiments, i.e. during the cooling cycle, the reduction of pore spaces and closures of some small pores caused by heating or thermal loading can not be totally recovered within a short period; (b) some possible permanent pore structure collapses introduced during the heating.
and cooling process, which may reduce the total pore spaces and increase the tortuosity of flow paths. The reason for the opposite hysteresis observed for some other samples may be because of the effect of micro-cracks created by the heating and cooling under a confining pressure which may open new current flow paths. Another possible contribution to the second hysteresis may be because the thermal equilibrium generally takes longer time to establish in the cooling cycle because of the small thermal gradient applied.

5.4 The Combined Effect of Pressure and Temperature

Both the pressure and temperature of oil reservoirs increase generally with depth, e.g. the deeper the reservoir, the higher the pressure and temperature. In addition, in the case of some recovery processes such as in situ combustion, hot water and steam injection, or cold water injection into a hot reservoir, not only the reservoir temperature but also the pressure may be altered. Therefore the separated examination of the effect of pressure and temperature on the electrical properties of rocks becomes less appropriate. To this end, experiments have been carried out to measure the electrical properties of sandstone rock samples, namely S1, S2, S3, S4 and S5, at coupled high pressure and temperature conditions. The results of formation factor versus confining pressure at various temperatures during both heating and cooling cycles obtained from these rocks are shown in Figs.5.24 - 5.28. These data were collected using the multi-sample rock testing rig by varying the confining pressure at fixed temperatures. An one hour interval between successive steps was allowed for stress equilibrium during both loading and unloading cycles, while a 12 hour interval was given for thermal equilibrium.

Panel (a) of Fig.5.24 shows that at a given temperature in the heating cycle the formation factor of S1 increases with confining pressure with a hysteresis between the loading and unloading testing cycles. The trend of the curves of F versus pressure during both loading and unloading cycles remains almost the same at different temperatures. Comparing panel (b) of the same figure where all data were collected during the cooling cycle with panel (a) where all data were collected during heating cycle, it is noticed that there is a temperature hysteresis between the values of F plotted in the two figures. Similar observations can be made in Figs.5.25 - 5.28 for different sandstone samples except the degree of the coupled pressure and temperature effect on the electrical properties of S2 and S4 is rela-
Fig. 5.24 $F$ vs. confining pressure at various temperatures: (a) measured during temperature increasing, (b) measured during temperature decreasing (sample S1).
Fig. 5.25 $F$ vs. confining pressure at various temperatures: (a) measured during temperature increasing, (b) measured during temperature decreasing (sample S2).
Fig. 5.26 $F$ vs. confining pressure at various temperatures: (a) measured during temperature increasing, (b) measured during temperature decreasing (sample S3).
Fig. 5.27 $F$ vs. confining pressure at various temperatures: (a) measured during temperature increasing, (b) measured during temperature decreasing (sample S4).
Fig. 5.28 $F$ vs. confining pressure at various temperatures: (a) measured during temperature increasing, (b) measured during temperature decreasing (sample S5).
tively less significant because these two rocks are more porous and permeable than the other three rocks. Another observation from Figs. 5.24-5.28 is that there seems to be a contradiction in the temperature hysteresis among the five rock samples during the coupled pressure and temperature experiments, *i.e.* the values of formation factor obtained in cooling cycles are in some cases (S2 and S4) greater than that obtained from heating cycles, while for S1, S3 and S5, the opposite has been observed. The hysteresis observed for sandstone S2 and S4 during the coupled temperature and pressure experiments may be explained by the similar relaxation effect or the time effect as mentioned previously in the individual pressure and temperature experiments, *i.e.* (a) during the cooling cycle, the reduction of pore spaces and closures of some small pores caused by heating or thermal loading can not be totally recovered within a short period; (b) some possible permanent pore structure collapses introduced during the heating and cooling process, which may reduce the total pore spaces and increase the tortuosity of flow paths. The reason for the opposite hysteresis observed for other samples may be because of the effect of micro-cracks induced by the heating and cooling under a confining pressure which may open new current flow paths. To confirm the existence of permanent micro-cracks after the temperature and pressure experiments, mercury injection capillary pressure studies and acoustic velocity measurements may be conducted. This, however, is a topic of future research. Another possible contribution to the second hysteresis observed here may also be because the thermal equilibrium may not be established in the cooling cycle if the same time interval (*e.g.* 2 hours) as in the heating cycle is allowed.

Although the variations in porosity for the relatively less porous and permeable rocks (S1 and S5), seem to be more significant than that for the rest, the difference ranging from 0.20% to 0.40% between the values of the estimated porosities based on the coupled pressure and temperature experiments and the summation of the individual experiments for all the five sandstones is rather small. The experimental results based on these five sandstones seem to agree with that reported by Hilchie (1964), *i.e.* the combined effect of pressure and temperature equals the sum of the two individual effects. The same conclusion can be drawn from the experiments of the effect of temperature at various confining pressures obtained by fixing the confining pressure and varying the temperature as shown by Fig. 5.29. Fig. 5.30 illustrates the curves of Archie cementation factor for sample S4 versus confining pressure at various temperatures with all the data collected from the temperature increasing cycles. It is noticed again here that the cementation
Fig. 5.29 $F$ vs. temperature under various confining pressures (sample S4).

Fig. 5.30 Cementation factor calculated after porosity correction vs. confining pressure at various temperatures (sample S4).
Fig. 5.31 $F$ vs. pressure and temperature in a 3D view (sample S1).

Fig. 5.32 $F$ vs. pressure and temperature in a 3D view (sample S2).
factor varies with pressure and temperature in the same manner as the formation factor. To show the combined effect of pressure and temperature more clearly and to show the difference of magnitude between the pressure and temperature effect for a particular rock, Figs.5.31 and 5.32 plot the F against pressure along the x-axis and against temperature along the y-axis for samples S1 and S2 in a three dimensional view.

Based on the limited number of cores tested, it is still not possible to draw general conclusions about the combined effect of pressure and temperature on the electrical properties of sandstone rocks especially the lower permeable ones. However, this study shows that the combined effect of pressure and temperature on the electrical properties of these sandstone rocks tested is found to be approximately the sum of their individual effect.

5.5 Parametric Study

In the previous sections, the effect of pressure and temperature on the formation factor and Archie cementation factor of sandstone cores have been described. It is now possible to study the petrophysical implications of the above experimental results. The following parametric study demonstrates the possible errors in the estimated values of rock porosity caused by ignoring of the effect of pressure, temperature and hysteresis.

5.5.1 Pressure

The resistivity of reservoir rocks is directly measured at in situ conditions during logging operations. However the calibration of logs is usually carried out at room conditions in laboratories using core samples obtained from the wells. Since the conditions of pressure and temperature are different, the Archie types of correlations between the porosity or saturation and the electrical resistivity established at room conditions are no longer valid to interpret the electrical log data. As shown by Figs.5.33 - 5.36, ignoring the effect of confining pressure on the cementation factor (m) during the log calibration leads to significant underestimations of the real in situ rock porosity. The higher the reservoir pressure or the deeper the reservoir, the more significant the difference between the real
Fig. 5.33 Comparison of true and log estimated porosity when the effect of pressure is ignored (sample S1).

Fig. 5.34 Comparison of true and log estimated porosity when the effect of pressure is ignored (sample S2).
Fig. 5.35 Comparison of true and log estimated porosity when the effect of pressure is ignored (sample S3).

Fig. 5.36 Comparison of true and log estimated porosity when the effect of pressure is ignored (sample S4).
porosity and the log estimated porosity. Another conclusion which may be drawn from these experimental results is that the under-estimation of the porosity of relatively less porous and less permeable (tight) rocks is usually more significant compared to these higher porous and permeable (loose) rocks. Table 5.1 illustrates the maximum difference in the true and log estimated porosities of 4 sandstones under a maximum test pressure of 32 MPa which corresponds approximately to an oil reservoir in the depth of 2500 mSS, when ignoring the effect of confining pressure on Archie cementation factor (m).

Table 5.1 Comparison of True and Estimated \( \phi \) Showing the Pressure Effect (\( P = 32 \) MPa, \( T = \) Room Conditions)

<table>
<thead>
<tr>
<th>Core No.</th>
<th>True ( \phi )</th>
<th>Estimated ( \phi )</th>
<th>Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0.128</td>
<td>0.116</td>
<td>9.4</td>
</tr>
<tr>
<td>S2</td>
<td>0.226</td>
<td>0.225</td>
<td>0.4</td>
</tr>
<tr>
<td>S3</td>
<td>0.151</td>
<td>0.145</td>
<td>4.0</td>
</tr>
<tr>
<td>S4</td>
<td>0.217</td>
<td>0.212</td>
<td>2.3</td>
</tr>
</tbody>
</table>

As listed in Table 5.1, up to 9.4% under-estimation in the rock porosity has been observed for sample S1, which is the least porous and least permeable one among the 4 samples listed. On the other hand only 0.4% error exists between the real and estimated porosity for sample S2 which is the most porous and permeable among the 4 samples listed. The results of other 2 samples (S3 and S4) lie somewhere in between the above two extreme cases as predicted. There seems to be a general trend between the error in porosity estimation from logs and the actual rock porosity and permeability. This suggests that if more comprehensive experimental data bases are available, some simple empirical correlations between the log estimated porosity and the real \textit{in situ} porosity may eventually be possible to account for the pressure effect without measuring each individual rock.

5.5.2 Temperature

As shown in Figs. 5.37 - 5.40, the effect of ignoring temperature corrections for the cementation factor (m) during the log calibration can also lead to significant
Fig. 5.37 Comparison of true and log estimated porosity when the effect of temperature is ignored (sample S1).

Fig. 5.38 Comparison of true and log estimated porosity when the effect of temperature is ignored (sample S2).
Fig. 5.39 Comparison of true and log estimated porosity when the effect of temperature is ignored (sample S3).

Fig. 5.40 Comparison of true and log estimated porosity when the effect of temperature is ignored (sample S4).
under-estimations of the true \textit{in situ} rock porosity. The higher the reservoir temperature or, in other words, the deeper the reservoir, the more significant the difference between the true and the log estimated porosity. Another conclusion that can be drawn from these experimental results is that the under-estimation of the porosity of relatively tight rocks is usually more significant than that for loose rocks. Table 5.2 lists the difference between the true and log estimated porosities of the 4 sandstones at a maximum test temperature of 127.9 °C which approximately corresponds to some North Sea oil reservoirs at depths around 3500 - 4000 mSS.

Table 5.2 Comparison of True and Estimated $\phi$ Showing the Temperature Effect ($T = 127.9$ °C, $P = 13.8$ MPa)

<table>
<thead>
<tr>
<th>Core No.</th>
<th>True $\phi$</th>
<th>Estimated $\phi$</th>
<th>Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0.127</td>
<td>0.114</td>
<td>10.2</td>
</tr>
<tr>
<td>S2</td>
<td>0.221</td>
<td>0.220</td>
<td>0.5</td>
</tr>
<tr>
<td>S3</td>
<td>0.149</td>
<td>0.144</td>
<td>3.4</td>
</tr>
<tr>
<td>S4</td>
<td>0.210</td>
<td>0.203</td>
<td>3.3</td>
</tr>
</tbody>
</table>

As listed in Table 5.2, up to 10.2% under-estimation in the rock porosity has been observed for sample S1, which is the tightest one among the 4 samples. On the other hand only 0.5% error exists between the true and estimated porosity for sample S2 which is the most porous and permeable one. The results of other 2 samples (S3 and S4) lie somewhere in between the above two extreme cases as predicted. It may be suggested that both pressure and temperature have very similar influences on the accuracy of \textit{in situ} porosity estimations based on these sandstones tested. This further suggests that if more comprehensive experimental data bases are available, simple empirical correlations between the log estimated porosity and the real \textit{in situ} porosity may be possible to account for both the pressure and the temperature effect without conducting special core analysis on each individual rock.
5.5.3 Pressure and Temperature

Table 5.4 lists the errors in the porosity estimation from well logs calibrated at room conditions of pressure and temperature. The “true” reservoir condition porosities of these sandstone rocks are determined using the two pore fluid interface units as described in Chapter 4. The “estimated” porosities are obtained using reservoir condition formation resistivity factors and the room condition Archie cementation factors.

As much as 13.9% porosity under-estimation has been observed for S1 which is the tightest core listed. For the most porous and permeable core S2 the under-estimation in porosity is only 1.0%. S3 and S4 lie somewhere between the above two extreme cases with 6.1% and 4.0% under-estimation in porosity respectively.

Table 5.3 Comparison of True and Estimated $\phi$ Showing Combined Effect of P and T (T = 127.9 °C, P = 32 MPa)

<table>
<thead>
<tr>
<th>Core No.</th>
<th>True $\phi$</th>
<th>Estimated $\phi$</th>
<th>Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0.122</td>
<td>0.105</td>
<td>13.9</td>
</tr>
<tr>
<td>S2</td>
<td>0.197</td>
<td>0.195</td>
<td>1.0</td>
</tr>
<tr>
<td>S3</td>
<td>0.147</td>
<td>0.138</td>
<td>6.1</td>
</tr>
<tr>
<td>S4</td>
<td>0.198</td>
<td>0.190</td>
<td>4.0</td>
</tr>
</tbody>
</table>

5.5.4 Hysteresis Effect

The hysteresis occurring during both pressure and temperature experiments suggests that not only the reservoir pressure and temperature conditions but also the history of the changes of pressure and temperature influence the formation resistivity and porosity. For instance, although during laboratory tests rock samples may be placed in exactly the same pressure and temperature conditions as found in the in situ reservoirs, the rock properties may still be different due to the hysteresis effect. Table 5.4 illustrates the errors in porosity estimation if the hysteresis effect is ignored.
Table 5.4 The Hysteresis Effect on $\phi$ Estimation

$(T = 127.9^\circ C, P = 32$ MPa$)$

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Error in $\phi$ Pressure Hyst.</th>
<th>Error in $\phi$ Temperature Hyst.</th>
<th>Total Error %</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>0.44</td>
<td>-0.12</td>
<td>0.32</td>
</tr>
<tr>
<td>S2</td>
<td>0.11</td>
<td>0.13</td>
<td>0.25</td>
</tr>
<tr>
<td>S3</td>
<td>0.20</td>
<td>-0.13</td>
<td>0.07</td>
</tr>
<tr>
<td>S4</td>
<td>0.10</td>
<td>0.09</td>
<td>0.19</td>
</tr>
</tbody>
</table>

It is shown in Table 5.4 that the total error in porosity estimation (either under-estimation or over-estimation depending on the sequences of changes in pressure and temperature) due to hysteresis effect ranges from 0.07% to 0.32%, which are of second order magnitude compared to the actual pressure and temperature effect. The negative signs in the table show that the effect of temperature hysteresis cancels some of the pressure hysteresis for some rocks.

5.6 Conclusions

a. A novel reservoir condition multi-sample electrical property apparatus has been established for experimental measurements on a range of rocks.

b. Significant increases in both $F$ and $m$ with pressure and temperature have been observed. The changes of the electrical properties of these clay-free sandstones with pressure and temperature are attributed to the changes in porosity and pore constrictions caused by rock deformations and rock matrix expansions.

c. Ignoring the effect of pressure and temperature on Archie cementation factor ($m$) during the log calibrations leads to under-estimations of porosity up to 14% for these clay-free sandstones tested. The effect of pressure and temperature on the degree of under-estimations of rock porosity is found to be much more pronounced for these low porosity and low permeability rocks.

d. The hysteresis occurring during both pressure and temperature experiments suggests that not only the reservoir pressure and temperature conditions but
also the history of the changes of pressure and temperature influence the formation resistivity and porosity. Comparing with the actual pressure and temperature effect on porosity estimation, the hysteresis effect, however, is of second order magnitude.

e. The combined effect of pressure and temperature on the electrical properties of these sandstone rocks tested is found to be approximately the sum of their individual effect.

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CHAPTER 6

THE EFFECT OF CLAY ON THE ELECTRICAL PROPERTIES OF SHALEY ROCKS AT RESERVOIR CONDITIONS
6.1 Introduction

Although there are many empirical shaley sand conductivity models available in the literature, in practice none may be used directly without careful calibration based on some reliable experimental data. This is because (a) these models may not represent all the prevailing mechanisms of the conductive behaviour of shaley sands, and (b) empirical correlations of the clay content ($Q_v$) or some related quantity with a log-derived parameter are needed before these models can be used. In addition, the effect of temperature on the resistivity of clean and shaley rocks remains unquantified due to the lack of appropriate experimental measurements. To investigate the effect of clay minerals on the electrical properties of shaley rocks at room and reservoir conditions, synthetic shaley samples are used in this study because of the advantage that samples with desired clay type, content and distribution mode can be made and their clay content ($Q_v$) can be accurately determined.

This chapter presents a new method for making synthetic shaley rock samples for the study of the rock electrical and hydraulic properties at reservoir conditions. The effect of temperature and pressure on the apparent formation factor and cementation factor for the shaley sands is described. A comparison between some significant shaley sand conductivity models and experimental results obtained from 14 shaley samples is also given. This study shows that both the W-S (Waxman and Smits 1968) and the D-W (Clavier et al. 1977, 1984) shaley sand conductivity models apply adequately at room conditions to homogeneous samples with dispersed clays which are uniformly distributed. For other clay distributions and for shaley sands at elevated temperatures, however, these well-known shaley sand conductivity models can no longer be applied accurately. A modified version of the W-S model is, therefore, proposed by including a temperature coefficient ($\omega$) for the equivalent clay counterion conductivity, which is a function of temperature and clay content, and a clay distribution coefficient ($\tau$) for the clay content ($Q_v$). The values for $\omega$ as a function of temperature and clay content, and $\tau$ as a function of clay distribution modes are given. Similarly, other shaley sand conductivity models such as the D-W can also be improved to cover the effect of temperature and clay distribution. An experimental data base generated in this chapter will be used later in Chapter 8 for the network modelling of the effect of clay minerals on the shaley sand conductivity.
6.2 Previous Studies Using Synthetic Samples

Synthetic samples made up with sands or glass beads have been used frequently over the past to study the fluid and electrical current flow in porous media. The reason for using synthetic samples in these previous studies is that the complex interconnected pore spaces of natural rocks can be closely assembled and the effect of particle shapes on the transport properties of rocks can be experimentally determined. The previous studies using synthetic samples can be classified in two groups depending on the method of sample preparation, namely, unconsolidated and consolidated synthetic samples.

6.2.1 Use of Unconsolidated Samples

Wyllie and Gregory (1953) related the electrical properties of rocks to the shapes of rock forming particles using unconsolidated artificial porous media. A laboratory investigation was made by Jackson et al. (1978) on the formation resistivity factor and porosity relationships using artificial sand samples with a wide range of grain size and different grain shapes. Although these unconsolidated synthetic samples may be used to study the transport properties of rocks at ambient conditions, they cannot be used to investigate the effect of pressure and temperature on resistivity of rocks because their sand grains are very loosely packed.

6.2.2 Use of Consolidated Samples

Mandel et al. (1957) and Viksne et al. (1961) have used consolidated synthetic rock samples consisting of quartz sand grains mixed with cementing materials for electrical resistivity and acoustic measurements. The consolidation was carried out by pressurising the wet and homogeneous mixture and then allowing the cement to set. Although the amount of cement can be varied, this technique often produced heterogeneous cores without grain-grain contacts. Helander and Campbell (1966) later used an epoxy resin to make synthetic glass bead samples and sand cores, a technique originally designed by Havenaar and Meijs (1963) in completing the gas wells by applying resin in the form of a solution to glue loose sand grains without significantly reducing porosity and permeability in situ. Main disadvantage of this technique, however, was that the resulting cement was not
heat resistant imposing restriction for performing high temperature experiments. 
Lebreton et al. (1978) made large synthetic samples with mortar, which was a 
mixture of cement, sand, water and additive, for acoustic measurements. Very 
large samples could be produced using their technique but it was not possible to 
produce homogeneous samples. In addition the permeability of the samples was 
mainly attributed to fractures and the porosity was created by vugs and channels. 
A so-called “silica-lock” method for consolidating sand grains by flowing vapor-
ised silicon tetrachloride through a water-wet sand pack was proposed by Davies 
and Meijs (1980) to prevent sand production in unconsolidated gas wells. This 
method was suitable for making homogeneous artificial samples with direct grain-
grain contacts. A disadvantage, however, during the consolidation process was the 
violeat reaction of silicon tetrachloride with water, which required strict precau-
tions in the laboratory. Plona (1980) reported a method of making synthetic rocks 
by jointing glass beads at the grain contacts with heating. Small heterogeneous 
samples with a wide range of porosity and permeability could be obtained using 
this method. Due to the perfect roundness of the glass beads and the lack of 
cementing materials in the pore space, the packing characteristics here differ from 
those of natural sandstones.

After comparing many previous techniques of making consolidated synthetic 
rock samples, Visser (1988) developed a procedure for making homogeneous syn-
thetic samples for studying the acoustic properties of rocks. Three types of ce-
menting materials were used, i.e.,

a. silica produced from silicontetrahloride, so-called silica-lock,
b. silica produced from methylsilicate, and
c. araldite.

Precautions are required because cement (a) and (b) are toxic. The araldite 
cement was proved to be the most appropriate since reproducible, homogeneous 
synthetic samples, which resemble the natural rocks in terms of the acoustic char-
acteristics, can be obtained. However araldite is not high-temperature resistant.

It can be concluded that unconsolidated loose synthetic samples cannot be 
used to study the transport and elastic properties of rocks at reservoir conditions. 
Consolidated synthetic cores bonded by epoxy resin, silica cement or araldite can-
not be used either due to the difficulties in having effective clays as cementing 
materiats. The high temperature heating process (e.g. > 300 °C) involved in some 
core consolidation procedures may destroy the crystal structures of clays. In ad-
dition some cementing materials used such as epoxy resin may cover not only the sand grains but also most of the clay particles preventing direct contact between the clays and the electrolyte, therefore, preventing ion exchange.

In this study, clay minerals are used directly as the cementing materials to make synthetic rock samples with required properties including the effective clays with designed CEC. A novel experimental procedure of cyclic loading - unloading and heating - cooling has been developed to consolidate these synthetic core samples (Jing et al. 1990a).

6.3 Apparatus and Procedure for Sample Preparation

The multi-sample experimental apparatus for measuring the electrical properties of core plugs at elevated pressure and temperature has been described in Chapter 4. This section describes the new technique developed to make the synthetic shaley samples and to carry out the electrical resistivity and permeability measurements at simulated reservoir conditions of pressure and temperature.

6.3.1 Experimental Apparatus

Fig.6.1 (a) illustrates schematically the special synthetic core sleeve assemblies designed by ITR Ltd for this research to make synthetic shaley rock samples and to measure electrical properties, following the 4-wire principle, and permeability at reservoir conditions. The mixture of sand and clay is packed inside a heat shrink sample jacket with six wire electrodes woven into it. These six wires around the core correspond with the potential electrodes in the Viton sleeve to enable the measurements of voltages across all intervals along the core as shown in the same figure. The two fine stainless steel mesh discs on both ends of the core stop fine clay and sand particles being carried out by the pore fluid and also act as current electrodes having good contacts with the sample. The two Holland weave stainless steel mesh discs (or coarse mesh discs) between the fine mesh discs and the platens help retaining the sand and clay mixture. Fig.6.1 (b) shows the picture of 5 synthetic samples packed in the sample jackets.

Once the loose pack inside the sample jacket is placed into the Viton sleeve with all the wires around the core properly connected to the potential electrodes,
Fig. 6.1. (a) Schematic diagram of the ITR design for making synthetic rock samples.

Fig. 6.1. (b) Picture of 5 synthetic shaley samples with various clay distributions.
the procedure of loading all five sleeve assemblies into the multi-sample high pressure and temperature vessel is identical to that of loading natural rock samples as described previously in Chapter 4.

6.3.2 Experimental Procedure

(a) Synthetic Sample Preparation

The novel experimental procedure of cyclic loading - unloading and heating - cooling for preparing synthetic shaley samples using 4 ppm ion concentration silica sands and clays is as follows:

a. Determine the amounts of sands with different ranges of grain sizes and the cement materials in order to achieve the designed rock properties (Furnas 1931),
b. To make shaley samples with uniformly dispersed clays, mix the sands and clays until the loose pack becomes homogeneous, then pack the mixed minerals inside a synthetic sample jacket; To make samples with non-uniform, dispersed clays or with laminar clays, the sands and clays are packed into the sample jacket directly according to the distribution type required,
c. Insert the sample jacket into a Viton core sleeve, ensuring contact between the electrodes and the wires around the synthetic sample,
d. Pre-pack the mixed materials in the high pressure cell, then saturate the core with brine,
e. Repeat the cycles of loading and unloading on the core while measuring the electrical resistances and the pore volume deformations until the core has similar mechanical properties as natural rocks,
f. Repeat the cycles of heating and cooling until the results become reproducible like in the case of natural rocks, and,
g. Finally, start the measurements of the electrical and hydraulic properties on these synthetic shaley samples.

The synthetic core saturating process mentioned in step 4 was accomplished using an apparatus as shown in Fig.6.2 (a). The loose pack and the flow lines were vacuumed for over 12 hours to remove air from the system. Then de-aerated brine solution was allowed to fill the system. To further reduce air bubbles which may be trapped inside the core and the flow lines, the same brine was pumped through
the system under vacuum as shown by Fig.6.2 (b). The difference between this synthetic core saturating method and the technique for saturating natural rocks described in Chapter 4 is that high pressure is not needed to force the brine into the pore spaces since the loose sand and clay pack before consolidation is very permeable.

The porosity of the synthetic samples was calculated by comparing the total grain volumes of loose packs with the bulk volumes after consolidation. The effect of clay swelling on the porosity may be assumed to be negligible when high salinity brine solutions are introduced in the pore spaces of the synthetic samples.

(b) The Determination of Clay Content ($Q_v$)

The cation exchange capacity (CEC) of a solid material is a characteristic that describes the number of active points on the surface at which cations can be exchanged. The greater the CEC, the greater is the ability of the solid surface to conduct an electric current. The CEC of clays can be determined by various methods. Table 6.1 lists the average values of CEC for three types of clays determined by the methylene blue method recommended by API (1968).

<table>
<thead>
<tr>
<th>Clay Type</th>
<th>Source</th>
<th>CEC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montmorillonite</td>
<td>Surrey Powder, England</td>
<td>50.0</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>Kaolin Deposits, Georgia, USA</td>
<td>8.0</td>
</tr>
<tr>
<td>Illite</td>
<td>Cambrian Shale, Montana, USA</td>
<td>4.0</td>
</tr>
</tbody>
</table>

According to Grim (1968), accurate determination of CEC is very difficult to accomplish due to many factors such as the effects of particle size, grinding and temperature. The above mentioned methylene blue method may underestimate the CEC.

The volume concentration of clay exchange cations ($Q_v$), which is often simply referred as clay content, for real reservoir shaley samples can be obtained from the following equation:
Fig. 6.2 Schematic diagram of the synthetic sample saturators, (a) initial saturator; (b) core flooding apparatus.
\[ Q_v = \frac{CEC(1 - \phi)\rho}{100\phi}; (meq/cc) \]  

(6.1)

where, \( \rho \) = grain density of rock solids, grams/cc, \( \phi \) = total rock porosity, fraction.

For the synthetic samples used, equation (6.1) can be rewritten as:

\[ Q_v = \frac{CEC \cdot W_c}{100V_p}; (meq/cc) \]  

(6.2)

where, \( W_c \) = total amount of clay minerals, grams, \( V_p \) = total rock pore volume, cc. The \( Q_v \) can also be obtained from the plot of rock conductivity \( (C_o) \) vs. solution conductivity \( (C_w) \) using the shaley conductivity models such as W-S and D-W, the membrane-potential measurements (Thomas 1976, Steward and Burck 1986, Yuan and Diederix 1987 and de Waal 1989), and the \( Q_v \) - porosity correlations (Juhász 1981).

(c) Synthetic Core Consolidation

A technique of repeated loading - unloading and heating - cooling has been developed to consolidate the synthetic shaley samples (Jing et al. 1990a). This laboratory procedure in principle simulates the physical process of sedimentation and compaction of natural sandstone rocks.

Fig.6.3 (a) and 6.3 (b) show the electrical resistance and the total rock deformation for sample A5 as a function of confining pressure in different loading and unloading cycles as mentioned in above step 5 indicating the process of core consolidation. It is shown in the same figures that the curves of electrical resistance and rock deformation versus confining pressure shift upwards initially, then stabilise after about 6 testing cycles. The hysteresis observed during the loading and unloading sequence runs becomes relatively less significant as the number of test cycles increases. Similar results have been obtained for other synthetic samples.

The above experimental observations may be explained by looking at the positions of sand grains at micro-scale. After the initial packing inside the sample jacket, some sand grains may already be placed in a hexagonal close-packed form, but many of them may be placed in a loose cubic packing form or in between
Fig. 6.3.(a) Rock resistance vs. confining pressure in different packing cycles.

Fig. 6.3.(b) Rock deformation vs. confining pressure in different packing cycles.
these two extreme cases. Applying a confining pressure, the sand grains rotate and move in order to be packed in a more stable position such as the hexagonal close packing form. After certain cycles of increasing and reducing pressure, most of the sand grains may have been packed in a stable form. It becomes more difficult, therefore, to further reduce the porosity of the pack once all the grains are packed closely. As packing continues, eventually, the synthetic sample behaves in the same manner as natural sandstone rocks under confining pressure. This means that the resistivity and pore volume deformation readings under confining pressure are reproducible in different cycles such as cycle 7, 8 and 9 as shown in Fig.6.3. The above explanations may further be supported by studying the thin sections of synthetic samples before and after consolidation.

The reason for repeating the loading and unloading cycles is because much less time is needed for the dynamic consolidation process compared with simply applying a confining pressure and waiting for the equilibrium.

After the consolidation process, experiments have been carried out to investigate the changes in $F$ and $\phi$ as a function of temperature in different heating and cooling cycles as mentioned in above step 6. It has been found that after 2-3 cycles $F$ remains almost constant at any given temperature among different heating and cooling cycles. Fourteen synthetic shaley samples made up of different clay minerals and with various clay distribution modes have been prepared following the above procedure. Fig.6.4 shows the $F$ and $\phi$ for all the samples on a log-log scale after consolidation. There seems to be a correlation existing among these experimental data points. This might be a result of a coincidence due to the limited data points available. According to Grim (1968), different clay crystals have different shapes which may affect the total tortuosity of the rock. It may be suggested that the Archie cementation factor ($m$) varies for rocks with different types of clays.

(d) Rock Conductivity ($C_o$) vs. Solution Conductivity ($C_w$)

In order to establish the effects of the excess conductivity of clay minerals at various temperatures ($C_o$ vs. $C_w$ plot), experiments have been carried out to measure the conductivities of rocks at various brine concentrations. This experimental procedure, which is often called the “Multiple-Salinity” technique, was accomplished by flushing more than 20 pore volumes of de-aerated brine through
the core until no measurable change in resistance (within known error limits) is observed over several hours. The $C_o$ vs. $C_w$ plots at elevated temperatures were obtained by circulating de-aerated brine in an oil bath before flushing it through the core. The last temperature point (127.5 °C) was measured by flushing the core in a lower temperature below 100 °C, then increasing the temperature with a 1.4 MPa (200 psi) pore pressure applied to the core to prevent the evaporation of the brine.

6.4 Results and Discussion

Electrical resistivity and absolute permeability measurements have been carried out at simulated reservoir conditions of pressure and temperature. This chapter reports the results of electrical properties of these synthetic shaley sands at various pressure and temperature conditions. The results of permeability study on the synthetic shaley samples are presented in Chapter 7.

For each pressure and temperature, readings were taken when the brine level in the calibrated glass burette stops moving and the voltages were stabilised. It took about 30 minutes to reach the stress equilibrium and 2 hours to reach the thermal equilibrium, with a pressure change of about 3.45 MPa and a temperature difference of about 20 °C. Some experiments have been conducted to study the data stability by prolonging the time interval to more than 24 hours. For the study of hysteresis, data were taken in both cycles. One such experiment involved increasing pressure and temperature from lower limits, and another reducing pressure and temperature from the upper limits. Table 6.2 lists 14 shaley samples prepared and tested.

6.4.1 The Effect of Confining Pressure

Fig.6.5 shows the effect of confining pressure on apparent formation factor (F) for 5 synthetic samples saturated with 5% NaCl brine, namely, A1, A3, A11, A12 and A14. It indicates that F increases significantly with confining pressure over a pressure range from 0 to 30 MPa, and F values measured in the unloading cycles are higher than those measured in the loading cycles. Similar results were obtained for the other synthetic samples.
Fig. 6.4 $F$ vs. porosity for synthetic samples showing the cementation factor.

Fig. 6.5 $F$ vs. confining pressure for 5 synthetic samples at room temperatures.
Table 6.2: Synthetic Core Sample Information

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Diameter (cm)</th>
<th>Length (cm)</th>
<th>$\phi$ (%)</th>
<th>Clay Type</th>
<th>Clay Dist.</th>
<th>Clay Content % weight</th>
<th>$Q_v$ meq/cc</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>3.567</td>
<td>7.454</td>
<td>29.66</td>
<td></td>
<td></td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>A2</td>
<td>3.553</td>
<td>7.847</td>
<td>29.85</td>
<td>Mont.*</td>
<td>Dispersed</td>
<td>10</td>
<td>0.240</td>
</tr>
<tr>
<td>A3</td>
<td>3.475</td>
<td>6.990</td>
<td>28.86</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>15</td>
<td>0.544</td>
</tr>
<tr>
<td>A4</td>
<td>3.331</td>
<td>7.276</td>
<td>25.94</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>20</td>
<td>1.152</td>
</tr>
<tr>
<td>A5</td>
<td>3.430</td>
<td>7.500</td>
<td>29.67</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>10</td>
<td>0.297</td>
</tr>
<tr>
<td>A6</td>
<td>3.544</td>
<td>6.864</td>
<td>29.46</td>
<td>Kaolinite</td>
<td>Dispersed</td>
<td>10</td>
<td>0.020</td>
</tr>
<tr>
<td>A7</td>
<td>3.350</td>
<td>6.714</td>
<td>28.72</td>
<td>Illite</td>
<td>Dispersed</td>
<td>10</td>
<td>0.041</td>
</tr>
<tr>
<td>A8</td>
<td>3.420</td>
<td>6.740</td>
<td>28.55</td>
<td>Kaolinite</td>
<td>Dispersed</td>
<td>15</td>
<td>0.044</td>
</tr>
<tr>
<td>A9</td>
<td>3.600</td>
<td>6.330</td>
<td>27.72</td>
<td>Illite</td>
<td>Dispersed</td>
<td>15</td>
<td>0.093</td>
</tr>
<tr>
<td>A11</td>
<td>3.459</td>
<td>8.128</td>
<td>26.56</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>15</td>
<td>0.596</td>
</tr>
<tr>
<td>A12</td>
<td>3.489</td>
<td>7.994</td>
<td>28.42</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>15</td>
<td>0.542</td>
</tr>
<tr>
<td>A13</td>
<td>3.556</td>
<td>8.185</td>
<td>31.88</td>
<td>Mont.</td>
<td>Laminated</td>
<td>15</td>
<td>0.411</td>
</tr>
<tr>
<td>A14</td>
<td>3.499</td>
<td>8.237</td>
<td>31.18</td>
<td>Mont.</td>
<td>Laminated</td>
<td>15</td>
<td>0.477</td>
</tr>
</tbody>
</table>

* Mont. = Montmorillonite

The reason for the increase in $F$ of the synthetic samples with pressure appears to be simply due to the compression effect which reduces the pore sizes and changes the tortuosity of current flow paths. The amount of increase in resistivity appears different for different synthetic rocks depending upon the porosity, clay mineral composition and content (Jing et al. 1990a).

According to Fatt (1957), there was little or no difference between the data obtained during loading cycles and those measured during unloading cycles for the consolidated sandstone samples tested, if sufficient times were allowed to reach equilibrium. However, our results on synthetic rocks again show significant hysteresis occurring in all the high pressure measurements even after long time intervals of up to 12 hours. Similar to the hysteresis observed for natural sandstones,
the hysteresis observed here can be attributed to the “relaxation effect” or time
dependent rock elastic behaviour. Although it seems to be negligible, possible
further packing under elevated pressures may also contribute to the hysteresis by
rotating sand grains and reducing rock porosity.

The experimental results of Archie cementation factor (m) at various confining
pressures for sample A2, A3, A11 and A12 are shown in Figs.6.6 - 6.9. Prior to
correction for changes in porosity caused by overburden pressure, m seems to
increase dramatically with pressure for all the samples. After porosity correction,
however, the changes in m resulting from confining pressure become smaller, but
still noticeable. Similar to the formation factor plot as shown in Fig.6.5, there is
an obvious hysteresis occurring here between the loading and unloading cycles for
all the cores. This hysteresis observed might be explained in the same way as for
the plot of F versus confining pressure.

Similar results on cementation factor of natural sandstones at various pres-
sures have been reported by Jing et al. (1989) indicating that compression of the
rock causes more radical changes in resistivity and permeability than does the
change in porosity. Therefore, it might be concluded that the increase of resis-
tivity with confining pressure not only results from the rock deformation but also
from other sources such as changes of pore constrictions and perhaps changes in
the geometries of the electrochemical double layer associated with clay minerals
for shaley sands. The latter needs to be further investigated.

6.4.2 The Effect of Temperature

As shown in Fig.6.10, the results of the 6 samples (A2, A5, A6, A7, A8, A9)
measured at different temperatures illustrate that the apparent formation factor
at 5% NaCl concentration increases with temperature and exhibits hysteresis
between the heating and cooling cycles. Unlike the hysteresis observed during
the pressure test, this one shows that all the values of F measured during cooling
cycle are smaller than those measured during the heating cycle.

Fig.6.11 shows the results of Archie cementation factor plotted before and
after porosity corrections for sample A2 at various temperatures from ambient to
160 °C. A hysteresis similar to that in the F versus temperature plot is observed.
The variation of the slope of m versus temperature curve is also in the same manner
as the change of the slope of F versus temperature curve. The rate of change in F
Fig. 6.6 Cementation factor vs. confining pressure for sample A2 at room temperatures.

Fig. 6.7 Cementation factor vs. confining pressure for sample A3 at room temperatures.
Fig. 6.8 Cementation factor vs. confining pressure for sample A11 at room temperatures.

Fig. 6.9 Cementation factor vs. confining pressure for sample A12 at room temperatures.
Fig. 6.10 F vs. temperature for 6 synthetic samples under a confining pressure of 13.8 MPa.

Fig. 6.11 Cementation factor vs. temperature for sample A2 under a confining pressure of 13.8 MPa.
and \( m \) is smaller in the lower temperature range (e.g. 100 °C) than in the higher temperature range.

There are two particular factors influencing the electrical properties of both synthetic and natural shaley rocks at elevated temperatures. One is related to the thermal effects including thermal expansion and perhaps pore constriction changes. Another is the electrochemical effect associated with the clay minerals. Theoretically, as the temperature increases, thermal expansion increases the rock resistivity (Hilchie 1964, Sanyal 1972, 1973, Brannan and Gonten 1973 and Ucok 1979) while clay excess conductivity reduces the rock resistivity (Waxman and Thomas 1974, Parkhomenko 1982). Therefore the total effect of temperature on \( F \) and \( m \) depends on which particular factor dominates in a given rock. The increase of \( F \) and \( m \) with temperature results from not only the reduction of rock porosity but also the increase of rock tortuosity due to the thermal expansion under confining pressures. The above discussion is further supported by Fig.6.12 which shows the normalized formation factor against temperature for 6 synthetic samples with various amount of uniformly dispersed montmorillonite clay (except Al which is clay-free). As the clay content increases, the curves of normalized \( F \) vs. temperature shift down, then pass through a critical point around \( Q_u = 0.8 \), where the clay excess conductivity is balanced by the thermal expansion effect. Above the critical clay content the trend of \( F \) against temperature changes as shown in Fig.6.12 for sample A4 and A10. The decrease in \( F \) with temperature is as a result of the domination by clay effects because A4 and A10 have higher clay contents.

One reason for the hysteresis occurring in the temperature experiment might be that the thermal equilibrium takes longer time to establish in the cooling cycle than in the heating cycle because of the smaller thermal gradient.

6.4.3 The Combined Effect of Pressure and Temperature

Fig.6.13 illustrates the combined effect of pressure and temperature on \( F \) for core A5. These data were collected using the multi-sample rock testing rig with long equilibrium time intervals of up to 12 hours for each temperature change and 1 hour for each confining pressure change. The effects of confining pressure on \( F \) at higher temperatures are similar to such effects at lower temperatures. The effects of temperature at higher pressures are similar to such effects at lower pressures. It
Fig. 6.12 Normalized $F$ vs. temperature for 6 synthetic samples under a confining pressure of 13.8 MPa showing the effect of clay content.

Fig. 6.13 $F$ vs. confining pressure at different temperatures (sample A5).
may be concluded, therefore, that the combined effect of pressure and temperature on the electrical properties of the synthetic shaley rocks tested is approximately the sum of their individual effects.

As shown in Fig. 6.13, one loading and unloading test cycle was repeated at 54.2 °C to compare the F values. It has been found that there is little difference in the rock electrical properties between the two testing cycles. This further indicates that the synthetic sample has been consolidated and therefore behaves like a natural rock at elevated pressures and temperatures.

The pore fluid in both pressure and temperature experiments mentioned above is 5% NaCl brine. The effect of brine salinity has not been considered. The following sections, therefore, extend this study to the "multiple-salinity" cases.

6.4.4 Prediction of Core Conductivity

The non-linear characteristic of the \( C_o \) vs. \( C_w \) plot for shaley sands requires an understanding of the effect of pore fluid salinity on rock conductivity. The term "formation factor (F)" used previously, which is often called the "apparent formation factor" for shaley sands, does not remain constant as formation water concentration varies. In many shaley sand conductivity models, therefore, formation factor has been defined differently as a parameter independent of pore fluid salinity. These later defined formation factors provide a basis for Archie type empirical correlations between porosity, saturation and resistivity for shaley sands.

Following the "Multiple-Salinity" testing procedures mentioned earlier, conductivities of all the synthetic samples were measured at room temperatures with 5 different brines, namely 120, 50, 20, 5 and 2 grams/litre. The conductivities of the 5 solutions at room temperatures range from 0.5 mho/m to 14 mho/m. For comparison, Archie equation (Archie 1941) and three significant shaley sand conductivity models as reviewed in Chapter 3, i.e., P-W (Patnode and Wyllie 1950), W-S (Waxman and Smits 1968) and D-W (Clavier et al. 1977, 1984), are used to model the experimental results of the 14 synthetic rock samples.

(a) Comparison of Some Significant Shaley Sand Conductivity Models

Although both the W-S and D-W shaley sand conductivity models have been
widely used in the industry, different values of the variables in the models are often used in order to achieve better representation of rock electrical properties for specific reservoirs. Table 6.3 lists the values of the variables in the three shaley sand conductivity models used in this study.

Table 6.3: List of the Values of Variables in the Shaley Models

<table>
<thead>
<tr>
<th>P-W Model</th>
<th>W-S Model</th>
<th>D-W Model*</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_{sh} = 4$ (ohm $\cdot$ m)</td>
<td>$a = 0.6$ (dimensionless)</td>
<td>$\alpha = \sqrt{\frac{0.2356}{n}}$ (dimensionless), $n$ in m/l if $n &gt; 0.2356$ $\alpha = 1.0$</td>
</tr>
<tr>
<td>$\gamma = 0.013$ (mho/cm)</td>
<td>$\beta = 2.05(1 - 0.4e^{-2C_w})$</td>
<td></td>
</tr>
<tr>
<td>$\lambda_{Na} = 38.3$ (cm$^2$equiv$^{-1}$mho)</td>
<td>$\nu_Q = 0.3$ (dm$^3$/meq)</td>
<td></td>
</tr>
<tr>
<td>$F^*$ from $C_o$ vs. $C_w$ (dimensionless)</td>
<td>$F_0 = \frac{1 - \nu_Q Q_v}{F^*}$ (dimensionless)</td>
<td></td>
</tr>
</tbody>
</table>

* There is a limit of $Q_v$ around 2.5 meq/cc when applying D-W

Figs.6.14 - 6.18 show the experimental results and the model predictions of rock conductivities by Archie equation (equation 2.4), P-W model (equation 3.1), W-S model (equation 3.7) and D-W model (equation 3.9) for core A1, A2, A3, A4 and A10. The measurements were carried out with the samples maintained at an effective stress of 6.9 MPa (1,000 psi). The results suggest that for clean (clay free) rock sample (A1) the Archie equation applies at any of the solution conductivities ($C_w$) and the P-W, W-S and D-W models can be simplified to the Archie equation. As $Q_v$ increases, the departure of $C_o$ vs. $C_w$ curve from a straight line becomes obvious, and the difference between the model predictions of the shaley sand conductivity becomes more significant. The figures also revealed
Fig. 6.14 Shaley sand conductivities measured and predicted (sample A1).

Fig. 6.15 Shaley sand conductivities measured and predicted (sample A2).
Fig. 6.16 Shaley sand conductivities measured and predicted (sample A3).

Fig. 6.17 Shaley sand conductivities measured and predicted (sample A4).
Fig. 6.18 Shaley sand conductivities measured and predicted (sample A10).

Fig. 6.19 Shaley sand conductivities measured and predicted for 4 samples containing kaolinite and illite.
that the differences between the four models are most pronounced at low water conductivities.

The sharp decrease in conductivity with decreasing concentration of electrolyte in the dilute range of the $C_o$ vs. $C_w$ curves as observed in experiments is attributed to a decreasing exchange-cation mobility (Waxman and Smits 1968). At some relatively high concentration of equilibrating electrolyte solution (e.g., 2 mho/m according to W-S), the rock conductivity decreases linearly with decrease in solution conductivity because the exchange-cation mobility reaches its maximum value and remains constant. According to the D-W model proposed by Clavier et al. (1977), the departure of $C_o$ vs. $C_w$ curve from a straight line may be explained by the expansion of the salt-free layer. The expansion factor ($\alpha$) of the diffuse layer as used in the D-W model remains minimum at relatively high concentration of solution. As $C_w$ decreases below certain level (e.g., 2.5 mho/m according to D-W), the salt-free layer expands beyond the so-called “Outer Helmholtz Plane”, consequently, the rock conductivity decreases sharply and deviates from a straight line.

Fig.6.19 shows the experimental results of $C_o$ vs. $C_w$ for core A6, A7, A8 and A9 which have various amounts of kaolinite or illite respectively. Although these rocks have similar bulk clay contents as those montmorillonite shaley samples, the clay effects on the rock conductivity are relatively insignificant as indicated by Fig.6.19 because of their small cation exchange capacities. Therefore, only montmorillonite clay is of interest in the following sections because of its high cation exchange capacity.

Inspection of these $C_o$ vs. $C_w$ figures leads to the following conclusions.

a. Applying the Archie equation in the interpretation of shaley sand conductivity may lead to erroneous estimates of rock petrophysical properties because it does not consider the clay excess conductivity. Both over-estimate and under-estimate of true rock conductivity are possible depending on whether the in situ brine conductivity is higher or lower than the pore fluid conductivity of the core samples tested in the laboratory.

b. The Patnode-Wyllie (P-W) model does not represent actual rock conductivity relationships adequately because it assumes that the “conductive solids” conductivity is constant and independent of water conductivity. As shown by Figs.6.15 - 6.18, the curvature of the $C_o$ vs. $C_w$ plots of shaley rocks cannot
be modelled by the P-W.

c. Both W-S and D-W models may be applied for the interpretation of shaley sand conductivities with nearly the same accuracy. By selecting different values for the empirical constants in both models, the accuracy may be further improved for a particular shaley reservoir rock. Therefore, although the D-W model is theoretically more advanced, it gives nearly the same accuracy in modelling experimental results as W-S model because both models are based on the same initial over-simplified assumptions.

(b) The Effect of Temperature on Clay Excess Conductivity

Four shaley sand cores containing effective clay concentrations ($Q_v$) varying from 0.240 to 1.152 meq/cc have been used in this study. These shaley sand samples are described in Table 6.2. The cores were equilibrated with 3 NaCl brine solutions: 120, 50 and 20 grams/litre. The electrical conductivities were measured at 5 temperatures: 22.1, 55.7, 76.3, 99.2 and 127.5 °C.

The electrical conductivity measurements were carried out with the samples maintained at a net confining pressure of 6.9 MPa (1,000 psi), consisting of a fixed external pressure of 8.3 MPa (1,200 psi) on the rock matrix and 1.4 MPa (200 psi) on the internal aqueous phase. Resistance equilibrium (less than 0.5% variation in resistance) after each temperature increment was obtained by waiting for about 12 hours (over-night).

Figs.6.20 - 6.23 show the electrical conductivities of 4 shaley sands (A2, A3, A4 and A5) containing various amounts of montmorillonite vs. equilibrating brine conductivities at various temperatures. As temperature increases, the slopes ($\frac{1}{F^*}$ according to W-S) of the straight line portions of the $C_o$ vs. $C_w$ curves decrease while the $C_o$ intercepts ($\frac{BQ_v}{F^*}$ according to W-S), obtained by extrapolation of the straight-line portions of the conductivity curves, increase with temperature. The decrease in the slope further indicates the increase of the formation factor ($F^*$) with temperature as a result of thermal effect. The increase in the $C_o$ intercept with temperature reveals that the equivalent conductance of the clay counterions ($B$) increases accordingly since $F^*$ increases with temperature while $Q_v$ remains constant by definition. This increase in $B$ with temperature may be attributed to the increase in the ion mobility within the layer of clay bound water. Therefore,
Fig. 6.20 $C_o$ vs. $C_w$ at various temperatures. Confining pressure remains unchanged at 6.9 MPa (sample A2).

CORE A2
$Q_v = 0.240$ meq/cc
- 22.1 °C
- 76.3 °C
- 127.5 °C

Fig. 6.21 $C_o$ vs. $C_w$ at various temperatures. Confining pressure remains unchanged at 6.9 MPa (sample A3).

CORE A3
$Q_v = 0.544$ meq/cc
- 22.1 °C
- 76.3 °C
- 127.5 °C
Fig. 6.22 $C_o$ vs. $C_w$ at various temperatures. Confining pressure remains unchanged at 6.9 MPa (sample A4).

CORE A4

$Q_v = 1.152 \text{ meq/cc}$

- 22.1 °C
- 76.3 °C
- 127.5 °C

Fig. 6.23 $C_o$ vs. $C_w$ at various temperatures. Confining pressure remains unchanged at 6.9 MPa (sample A5).

CORE A5

$Q_v = 0.297 \text{ meq/cc}$

- 22.1 °C
- 76.3 °C
- 127.5 °C
the $C_o \text{ vs. } C_w$ plot not only shows the clay effect on the shaley sand conductivity by the $C_o$ intercept but also shows the thermal effect by the slope of the straight line portion.

The experimental results presented in Figs. 6.20 - 6.23 are fitted with the W-S shaley sand conductivity model in order to find the temperature coefficient ($\omega$) for the maximum equivalent ionic conductance of sodium exchange cations associated with clay ($\lambda_{Na}^{e}$). A temperature coefficient ($\omega$) is defined in this study as the ratio of the $\lambda_{Na}^{e}$ at elevated temperatures over that at room temperatures (e.g. 22 °C). Fig. 6.24 shows the experimentally determined values of $\omega$ at various temperatures from 22 to 127 °C with effective clay content ($Q_v$) ranging from 0.240 to 1.152 meq/cc. The following generalised observations may be made after inspecting the experimental results.

a The temperature coefficient ($\omega$) for the equivalent conductance of clay counterions increases with temperature.

b The increase of $\omega$ with temperature is more significant for shaley sands with relatively small effective clay content ($Q_v$).

Observation (a), which may be attributed to the increase in the ion mobility with temperature, agrees with the experimental results reported by Waxman and Thomas (1974). Observation (b), however, reveals an important new aspect of the conductive behaviour of shaley rocks at elevated temperatures. The less significant increase in $\omega$ with temperature for more shaley rocks may be due to the limitation in the increase of ion mobility with temperature as a result of the interaction among the highly concentrated ions. The interference between neighbouring electrical double layers within the very shaley rocks may also contribute to the above observation (b). After considering the temperature effect on shaley sand conductivity, the W-S model (equation 3.7) may be modified as follows (Jing 1990):

$$C_o = \frac{1}{F'}(\omega BQ_v + C_w)$$

(6.3)

where

$F' = \text{apparent shaley sand formation factor at a given temperature and pressure, which is the slope of the straight line portion of the } C_o \text{ vs. } C_w \text{ plot,}$
Fig. 6.24 Temperature coefficient for clay equivalent conductivity vs. temperature and clay content ($Q_v$).
\( \omega = \) temperature coefficient for the equivalent conductance of the clay counterions, which is a function of temperature as well as effective clay content \((Q_v)\) as shown in Fig.6.24. For particular reservoirs with different clay types, experiments may be required to estimate the constant \(\omega\) since this study only considered the montmorillonite and NaCl brine case.

\( B = \) equivalent conductance of the clay counterions as defined in equation (3.7.b) by Waxman and Smits (1968).

Waxman and Thomas's (1974) experimental results on some shaley sandstones showed that the apparent shaley rock formation factor \(F^*\) was temperature independent. However, our experimental results on both natural sandstone rocks and synthetic shaley rocks indicate an increase in \(F^*\) with temperature as a result of thermal expansion of rock forming materials which may reduce the total porosity and change the pore constriction.

The experimental results conducted on 4 shaley samples containing various amount of kaolinite and illite (A6, A7, A8 and A9) at elevated temperatures up to 160 °C show that there is not a remarkable increase in shaley rock conductivity due to temperature increase. This may also be explained by the fact that these synthetic rock samples have relatively very small \(Q_v\) values of less than 0.1 meq/cc.

(c) The Effect of Clay Distribution on Shaley Sand Conductivity

Four shaley samples with similar clay contents but different clay distribution modes were chosen in this study. These are A3, A12, A13 and A14 as listed in Table 6.2. We define two terms "Degree of Dispersion (DOD)" and "Degree of Lamination (DOL)" to describe the fraction of the clay volume per unit volume of reservoir rock for dispersed and laminated clay distribution respectively. Although the definitions of DOD and DOL are similar to the \(V_{gh}\) concept reviewed in Chapter 3, there is a fundamental difference: \(V_{sh}\) includes the fraction of clay and clay bound water, which may only be determined by logs, whereas both DOD and DOL can be estimated from logs and petrographic analysis.

Table 6.4 lists the details of 4 shaley samples with various montmorillonite clay distribution modes.

Fig.6.25 shows the \(C_o\) vs. \(C_w\) plots determined experimentally (symbols) and fitted by W-S model (lines) for the 4 shaley samples (A3, A12, A13 and A14). The
experimental data was modelled by varying the values of $Q_v$ used in the W-S until the best fit was achieved. The difference between the $Q_v$ measured and predicted is also shown in the above table.

Table 6.4: Details of 4 Shaley Samples with Different Clay Distributions

<table>
<thead>
<tr>
<th>Core No.</th>
<th>$Q_v$ Measured</th>
<th>$Q_v$ Predicted</th>
<th>Dist. Type*</th>
<th>$DOD$ or $DOL$</th>
<th>Orientation</th>
</tr>
</thead>
<tbody>
<tr>
<td>A3</td>
<td>0.544</td>
<td>0.500</td>
<td>Dispersed</td>
<td>1.0</td>
<td></td>
</tr>
<tr>
<td>A12</td>
<td>0.542</td>
<td>0.400</td>
<td>Dispersed</td>
<td>0.30</td>
<td></td>
</tr>
<tr>
<td>A13</td>
<td>0.411</td>
<td>0.550</td>
<td>Laminated</td>
<td>0.27</td>
<td>$\parallel$ to Flow</td>
</tr>
<tr>
<td>A14</td>
<td>0.477</td>
<td>0.300</td>
<td>Laminated</td>
<td>0.34</td>
<td>$\perp$ to Flow</td>
</tr>
</tbody>
</table>

Dist. Type = Clay distribution types as shown in Fig.6.1.(b).

It may be suggested that if values of $Q_v$ derived from the conventional conductometric titration measurements are used in the interpretation of shaley sands, which ignores the influence of clay distribution, total clay effect can be underestimated for laminated clay distribution where the shale layers are parallel to the flow direction, while for dispersed clay, total clay effect can be overestimation depending on the $DOD$. For laminated clay with the shale layers perpendicular to the flow direction, the clay effect on shaley sand conductivity is likely to be overestimated.

In order to include the effect of clay distribution in the shaley sand conductivity models such as W-S and D-W, a term “effective clay concentration” is defined as $Q_{ve} = \tau Q_v$, which may be determined experimentally by the “Multiple-Salinity Method” or the “Membrane-Potential Method”, where $Q_v$ is the clay concentration derived from the cation exchange capacity (CEC) measurements and $\tau$ is a clay distribution coefficient relating the above two clay concentrations.

Considering the effect of clay distribution, the modified W-S model (Jing 1990) in the form of equation (6.3) may be written as:

$$C_o = \frac{1}{F_t} (\omega B \cdot \tau Q_v + C_w)$$

(6.4)

After considering the effect of temperature and clay minerals, an Archie type
Fig. 6.25 $C_o$ vs. $C_w$ for 4 shaley samples under a confining pressure of 6.9 MPa showing the effect of clay distribution.

Fig. 6.26 $Q_{ve}$ vs. $Q_v$ for 7 shaley samples showing the effect of clay distribution.
equation relating $F'$ to in situ porosity ($\phi$) exists:

$$F' = \frac{1}{\phi^{m'}}$$

(6.5)

where $m'$ is the temperature and pressure dependent cementation factor of shaley sands which can be determined experimentally accounting for the combined effect of temperature and pressure. Similarly, for the hydrocarbon zone, Waxman and Thomas's (1974) shaley sand conductivity model (equation 3.8) may also be modified by introducing the temperature and clay distribution coefficients:

$$C_t = C_o S_w' C_w + \omega B \cdot \tau Q_v / S_w$$

(6.6)

where $n'$ is the saturation exponent which depends on pressure, temperature and wettability for a given rock.

(d) Comparison of $Q_{ve}$ Obtained from Multiple-Salinity Measurements and $Q_v$ from the Chemical Analysis (CEC)

Values of $Q_v$, determined by chemical method (CEC measurement), may be compared with values of $Q_{ve}$ obtained from the W-S and D-W models using the $C_o$ vs. $C_w$ curves (Multiple-Salinity Method). Table 6.5 shows the chemical analysed values of $Q_v$ listed against the values of $Q_{ve}$ calculated from W-S model.

<table>
<thead>
<tr>
<th>Core No.</th>
<th>$Q_v$ from CEC</th>
<th>$Q_{ve}$ from $C_o$ vs. $C_w$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A2</td>
<td>0.240</td>
<td>0.200</td>
</tr>
<tr>
<td>A3</td>
<td>0.544</td>
<td>0.500</td>
</tr>
<tr>
<td>A4</td>
<td>1.152</td>
<td>1.000</td>
</tr>
<tr>
<td>A5</td>
<td>0.297</td>
<td>0.250</td>
</tr>
<tr>
<td>A12</td>
<td>0.542</td>
<td>0.400</td>
</tr>
<tr>
<td>A13</td>
<td>0.411</td>
<td>0.550</td>
</tr>
<tr>
<td>A14</td>
<td>0.477</td>
<td>0.300</td>
</tr>
</tbody>
</table>
Fig. 6.26 plots the $Q_{ve}$ vs. $Q_{v}$ for the shaley samples listed in Table 6.5. There is general agreement between the values of $Q_{ve}$ and $Q_{v}$ for sample A2, A3, A4 and A5, which are homogeneous samples with uniformly dispersed clay ($DOD = 1.0$). Sample A12, A13 and A14 are off-trend due to their different clay distribution modes.

A 3D pore space network model (Jing et al. 1990b) has been developed to relate the clay distribution coefficient ($\tau$) to the computer generated stochastic clay distributions. This model enables the practical application of the modified W-S model proposed in this study (equations 6.4 and 6.6). The details of the numerical study are presented in Chapter 8.

6.5 Conclusions

The following conclusions can be drawn based on the studies in this chapter:

a. A new method for making synthetic shaley rock samples for the study of rock electrical properties has been demonstrated. A reservoir condition multi-sample electrical property apparatus is used to study the electrical properties of synthetic shaley samples.

b. Significant changes in apparent formation factor and cementation factor with confining pressure and temperature of the shaley samples have been observed. The increase in rock resistivity with pressure is attributed to the rock deformation as well as changes of rock constrictions. The apparent $F$ and $m$ for shaley sands may increase or decrease with temperature depending on whether the thermal expansion effect or the clay excess conductivity dominates in a particular rock system.

c. The Archie equation and P-W model cannot be used to interpret shaley sands accurately especially for very shaley reservoirs and fairly shaley reservoirs with low brine concentrations, however both W-S and D-W models may be applied for interpreting the electrical conductivities of the shaley sands containing uniformly dispersed clays ($DOD = 1.0$) at room temperatures.

d. The W-S model has been modified by adding a temperature coefficient ($\omega$), which depends on the temperature and clay content, and a clay distribution
coefficient ($\tau$) which is a function of clay distribution type and the volume fraction of clays per unit volume of rocks. It is recommended that equations (6.4) and (6.6) should be used instead of the original W-S model in the interpretation of in situ shaley sand conductivities since they cover two more important aspects of the conductive behaviour of shaley sands. Following the same procedure, other shaley sand models like the D-W may also be improved to include the effect of temperature and clay distribution.

References


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Plona, T.J. Observation of a second bulk compressional wave in a porous medium.


CHAPTER 7

THE EFFECT OF PRESSURE, TEMPERATURE AND CLAY ON ABSOLUTE PERMEABILITY OF ROCKS
7.1 Introduction

Absolute permeability as a basic parameter in reservoir engineering calculations has traditionally been measured in the laboratory under conditions of temperature and pressure very different from those in the reservoir. As a result, unrealistic values of permeability are often used throughout a range of temperature and pressure, which may lead to erroneous calculations in well productivity and wrong predictions of future reservoir performance. Although there are numerous attempts in the literature to investigate the effect of confining pressure and temperature on the absolute permeability of porous media, no conclusion has yet been reached on how pressure and temperature influence the absolute permeability of a wide range of rocks.

This work investigates further the effect of pressure, temperature and clay minerals on the absolute permeability of natural and synthetic rocks. The multi-sample high pressure and temperature rock testing rig, described in Chapter 4, is used to measure the absolute permeability of 5 rock samples simultaneously at simulated reservoir conditions. Synthetic samples with various clay contents and clay distribution modes are made and used to study the clay effect on the absolute permeability of rocks with various pore fluids. The experimental results obtained from 5 natural sandstones and 7 shaley synthetic rock samples are described and discussed in this chapter. Finally the experimental data base established is used in the next chapter to simulate the experimental observations in the context of a 3D petrophysical model.

7.2 Literature Review

The effect of confining or overburden pressure on the absolute permeability of porous media has been studied by a number of authors. Fatt and Davies (1952) reported decrease in nitrogen air permeability of sandstones with an increase in confining pressure. Oil permeability of cores was measured under various confining pressures by McLatchie et al. (1957). They indicated that reduction of permeability in clean sands was relatively small while for sandstones containing large amounts of clay, very large reductions in permeability with increasing confining pressure was found. Asymptotic decreases in Klinkenberg permeability were
observed over the 0 - 24 MPa (3500 psi) range by Wyble (1958). A possible limit of the asymptotic decrease rate around 24 - 31 MPa (or 3500 - 4500 psi) was found and explained as that represented the maximum pressure which the formations had undergone during their geological life as a result of burial. During an experimental and theoretical study of some physical properties of sandstone rocks at elevated overburden pressures, Dobrynin (1962) related the reduction of absolute permeability at high pressures to the pore compressibility of rocks, and developed mathematical equations to predict the changes in permeability for the sandstones studied. Gray et al. (1963) studied the permeability anisotropy of several sandstones at high confining pressures. They showed that permeability reduction for 2 cylindrical cores was a function of the ratio of radial and axial stress. Kilmer et al. (1987) showed from a number of laboratory tests on low permeability sandstones that the permeability decreased when the confining pressure increased from 3.45 MPa (500 psi) to 34.5 MPa (5000 psi). The decrease was roughly 50% for 1 milli-Darcy and 80 - 90% for 10 microDarcy sandstones. For some higher permeability sandstones, Yale (1984) confirmed the trend as above: The decrease in permeability versus increase in hydrostatic load from 3.45 to 34.5 MPa was nearly 5% for 500 - 1000 milliDarcy sandstones. Holt (1989) observed relatively more pronounced reduction in permeability when the applied stress is non-hydrostatic: In particular, as failure was approached in triaxial loading or unloading, the permeability may be significantly reduced (in some cases to less than 10% of its initial value). Wei et al. (1986) conducted experiments on absolute permeability of sandstones at high pressures with various pore fluids. They showed a decrease in the permeability of the rocks with an increase in confining pressure. Absolute permeabilities to liquids were found to be significantly lower than Klinkenberg permeabilities for gases. A significant hysteresis effect was observed by Gobran et al. (1987) during the cyclic pressure experiments on unconsolidated sands.

The results of temperature effect on absolute permeability show much less consistency compared with the pressure effect, although the majority of published results show a decrease in absolute permeability with an increase in temperature. When studying flow of oil and water through both consolidated and unconsolidated sandstone, and stainless steel powder cores, Weinbrandt et al. (1975), Aruna et al. (1976), Daneshy et al. (1978) and Cassé and Ramey (1979) found a reduction in permeability with temperature increase with water flow but no change with oil flow. While the studies with sandstone as the porous medium by Somerton and Gupta (1965), Somerton et al. (1965) and Aktan and Farouq Ali (1975) indicated
an increase in permeability with temperature. Recently the studies on low permeability sandstones (Wei et al. 1986), medium permeability sandstones (e.g. 100 - 200 mD) and unconsolidated sand (Gobran et al. 1987) indicated that the absolute permeabilities are essentially temperature independent.

This study aims to provide an insight into the effect of pressure and temperature on the absolute permeability of rocks. The effect of clay minerals and pore fluid salinity on the absolute permeability of rocks is also studied using synthetic shaley rock samples with various amount of clay minerals and different clay distribution modes.

7.3 Experimental Apparatus and Procedure

The multi-sample experimental rig as described in Fig.7.1 is used to measure the absolute permeability of 5 core plugs simultaneously at elevated confining pressures and temperatures. This system comprises the multi-sample pressure vessel, a no-pulse solvent delivery pumping system providing a constant output of flow, two differential pressure transducers for measuring the pressure drop (\(\Delta P\)) across each rock sample and a clock for measuring the flow rate. Three multi-switch values are used for connecting each sample to the flow lines and measuring the pressure drops. A first stage pump is used to supply de-aerated brine to an ACS 351 solvent delivery system which then pumps brine into a small capillary tube at a constant flow rate and output pressure. The two differential pressure transducers [0.055 MPa (8 psi) and 0.552 MPa (80 psi)] were calibrated using a manometer and a dead-weight tested pressure transducer respectively. Fig.7.2 and Fig.7.3 show the calibration results and the least square fit equations. It is recommended that the differential pressure transducers need to be recalibrated regularly in order to ensure the accuracy of permeability measurements. A “short-circuit” loop is used to maintain zero pressure differential across the transducers when they are not in use.

Two stainless steel screens are mounted on the two end platens to prevent sand or clay migration into the flow system when the unconsolidated sand is tested. The core jacket is contained in a Viton sleeve with the ends tighten to the end platen with rubber rings to prevent confining-oil migration into the core during the core loading process.
Fig. 7.1 Schematic diagram of the experimental system for measuring the permeability of rock samples at reservoir conditions.
Fig. 7.2 Calibration of the differential pressure transducer (8 psi).

Fig. 7.3 Calibration of the differential pressure transducer (80 psi).
For permeability measurements at elevated temperatures, de-aerated brine is circulated in a 1/16" tube, which serves as a heat exchanger, through a constant temperature oil bath before it is injected into the cores. The maximum temperature in this study (i.e. < 100 °C), which is set by the vapour pressure of brines, can be increased if a back-pressure regulator is used to raise the pore pressure and, therefore, the boiling point temperature of the brines. At each pressure and temperature condition, the measurements start when the sample reaches stress, thermal and flow equilibria. The time allowed for the first two equilibria has been mentioned in resistivity measurements. The so-called flow equilibrium means that the ΔP across the core is stabilised. A multi-recorder is used to monitor the stability of differential pressures, the confining pressure and the temperatures continuously.

The value of permeability at any set of conditions is the average of the values at three different flow rates. The value at each flow rate is the average of the values after 5 and 10 incremental PV's provided the flow equilibrium has been reached. The absolute permeabilities of 5 sandstone and 7 synthetic rock samples with confining pressures ranging from atmospheric to 34.5 MPa (5000 psi) and temperatures ranging from ambient to 95 °C were measured.

7.4 Results and Discussion

Liquid permeabilities of 5 sandstone rocks of various origins as listed in Appendix C, which differ by up to three orders of magnitude, have been measured at elevated pressures and temperatures. These rocks are listed in Table 7.1.

As indicated by Table 7.1, liquid permeabilities (k_L) of all 5 rocks are smaller than the k∞ values for air after the Klinkenberg (1941) correction. This reduction of liquid phase absolute permeability, which generally increases with increasing liquid polarity, is caused by the rock/liquid interactions mainly as a result of dispersion of fine particles in the presence of liquids (Juhász 1986 and Wei et al. 1986). To minimise the effect of rock/liquid interaction, oil may be used instead of water or brine.
Table 7.1 List of Sandstones for Permeability Test

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Length (cm)</th>
<th>Area (cm²)</th>
<th>$k_{\infty}$ (md)</th>
<th>$k_L$ (md)</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>7.615</td>
<td>11.116</td>
<td>9.83</td>
<td>6.54</td>
</tr>
<tr>
<td>S2</td>
<td>7.670</td>
<td>11.187</td>
<td>3081.93</td>
<td>1023.21</td>
</tr>
<tr>
<td>S3</td>
<td>7.740</td>
<td>11.080</td>
<td>8.34</td>
<td>4.70</td>
</tr>
<tr>
<td>S4</td>
<td>7.608</td>
<td>11.151</td>
<td>873.39</td>
<td>321.22</td>
</tr>
<tr>
<td>S5</td>
<td>7.640</td>
<td>11.377</td>
<td>74.1</td>
<td>13.21</td>
</tr>
</tbody>
</table>

The following sections present the experimental results on the effect of pressure, temperature and clay on absolute permeability of natural and synthetic rocks.

7.4.1 The Effect of Confining Pressure

The absolute permeabilities of 5 sandstone samples are measured at elevated pressures with 5% (5 gram NaCl / 100 cc solution) brine as the flow medium. Fig. 7.4 (a) shows the results of the normalized liquid phase absolute permeabilities of 5 sandstones at various confining pressures ranging from atmospheric to 30 MPa. The normalized permeability is defined as the permeability at elevated pressures over that at atmospheric conditions. The following observations can be made based on the experimental results:

a. There is a decrease in absolute permeability with confining pressure for all 5 rocks tested. The rate of decrease is relatively higher in the low pressure range (e.g. < 10 MPa) than that at high pressure range.

b. For different rock types, the amount of decrease in the absolute permeability with confining pressure varies depending on their porosity and permeability. For instance, there is only a 10% decrease in permeability of sample S2 which is the most porous and permeable rock with 23.07% porosity and 321.21 mD permeability before the pressure test. For sample S1 which is the least porous and permeable rock among the 5 cores tested, up to 35% decrease in permeability is observed within the same pressure range. While for the other 3 samples, the curves of permeability against confining pressure lie somewhere in between the these extreme cases. The above observation agrees with the results presented by Yale (1984) and Kilmer et al. (1987).
Fig. 7.4.a Normalized permeability vs. confining pressure for 5 sandstone samples.

Fig. 7.4.b Normalized conductivity vs. confining pressure for the same 5 sandstone samples.
c. Comparing Fig. 7.4 (a) with Fig. 7.4 (b), it is interesting to notice that the change in permeability against pressure follows nearly the same trend as the change in the electrical conductivity factor (FCF), which is defined as the ratio of rock conductivity over the solution conductivity. The amount of change in permeability for the same rock within given pressure range, however, is generally greater than that of electrical conductivity.

The change of permeability with confining pressure may be explained in the similar way as for the electrical conductivity (Jing et al. 1989) which has been presented previously in Chapter 5. For example, the decrease in the absolute permeability of rocks with confining pressure is caused by the rock deformation which reduces the pore size, increases the tortuosity of the fluid flow paths and alters the internal surface roughness of pore spaces. The reason for the less significant change in permeability at higher pressure range is that rocks become less compressible as pressure increases due to the closure of small pores. There is a limit in the deformation of rock pore spaces before the pore structures collapse (Wyble 1958). The more significant decrease in permeability with pressure for less porous and less permeable rocks can be explained as tight rocks with a larger percentage of small pores can be compressed more effectively mainly as a result of the closure of these small pores. The similar trend observed in both permeability and electrical conductivity experiments at elevated pressures is due to the fact that both fluid flow and electrical current flow in the rock pore spaces are controlled by the pore size distribution, pore tortuosity and pore connectivity. The difference in the magnitude in the pressure effect on both the hydraulic and electrical conductivity of rocks, however, may be attributed to the following two reasons (Jing et al. 1990):

a. Fluid flow through a pore is controlled not only by the pore size, but also by the pore shape whereas the electrical current flow depends only on the pore size as described by Ohm's Law. Therefore as pressure increases, the resulted change in pore shape affects the permeability, but not the electrical conductivity.

b. The hydraulic resistance of a pore is proportional to \( r^4 \) as stated by Hagen-Pouiselle pipe flow equation, while the electrical resistance of the same pore is only proportional to \( r^2 \), where \( r \) is the radius for cylindrical pores, or the equivalent pore radius for any other pore shape. As a result, the flow map (either potential or velocity distribution) for fluid is different from that for electrical current in a porous media. Small pores contribute more to the
electrical current flow than to the fluid flow. As pressure varies, both hydraulic and electrical flow maps change differently according to the pore size change. This may be further supported in the next chapter using a 3D pore space petrophysical model.

Fig.7.5 and Fig.7.6 plot the absolute permeability of sample S1 and S2 in both loading and unloading pressure cycles showing the hysteresis effect. The error bars as shown in above two plots, calculated with an error analysis technique taking the differential of permeability equation and knowing the error in each individual measurement, indicate the maximum error occurring in the permeability measurements at a given pressure. For both rocks, the permeabilities obtained in the unloading cycle are lower than that obtained in the loading cycle although the hysteresis effect is of the second order magnitude compared to the actual pressure effect in the given pressure range. The observed hysteresis in permeability measurements at elevated pressures is attributed to the “relaxation effect” or some possible permanent pore structure changes induced by loading and unloading. Since the permeability finally goes back to the original point before loading, the permanent damage seems to be insignificant within the pressure ranges of interest.

7.4.2 The Effect of Temperature

Fig.7.7 shows the effect of temperature on absolute permeability of two rocks (S1 and S3) at a fixed net confining pressure of 13.8 MPa. The error bars indicate that the errors in the absolute permeability measurements are in the order of 3 to 5% in this study. There is a decrease in absolute permeability as temperature increases from ambient to 93 °C for both rocks tested. The amount of decrease in absolute permeability within the given temperature range, however, varies according to the rock type. Although it is difficult to draw any general conclusion based on limited number of cores tested, a similar trend as observed in the electrical resistivity study at elevated temperatures seems to occur, i.e. the temperature effect on absolute permeability is more significant for less porous and less permeable rocks.

The decrease of rock absolute permeability with temperature may be explained by the thermal expansion of rock forming materials under a confining pressure which reduces the pore sizes, changes the pore tortuosity and pore roughness. The possible closure of small pores at elevated temperatures may also contribute
Fig. 7.5 Permeability vs. confining pressure for S1 showing the hysteresis effect.

\[ k(o) = 6.54 \text{ mD} \]

Fig. 7.6 Permeability vs. confining pressure for S2 showing the hysteresis effect.

\[ k(o) = 321.22 \text{ mD} \]
Fig. 7.7 Permeability vs. temperature for sample S1 and S3. Confining pressure remains at 13.8 MPa.
to the reduction in permeability. The more significant decrease in permeability of tight rocks with increasing temperature may be due to the more effective change of rock tortuosity and pore roughness and the possible closure of small pores.

Some previous studies (Somerton and Gupta 1965, Somerton et al. 1965 and Aktan and Farouq Ali 1975) found increase in absolute permeability with temperature. For clean (clay-free) rocks, the possible increase of permeability with temperature may be due to the thermal induced micro-cracking which opens new flow path or due to the change of the degree of rock/fluid interaction which may increase the free pore space for fluid flow. The effect of temperature on the thickness and ion mobility of electrical double layer near the surface of clay minerals may also contributes to the possible increase in absolute rock permeability.

7.4.3 The Effect of Clay

In order to study the effect of clay and pore fluid salinity on the absolute permeability of rocks, synthetic shaley rock samples are made and tested with various brines. Table 7.2 lists the 7 synthetic samples tested. The effect of clay minerals on the absolute permeability of synthetic rock samples with various NaCl brine concentrations has been investigated. As a new attempt, the effect of clay distribution on absolute permeability of rocks is also considered in this study. Fig.7.8 shows the variations in brine permeability against solution concentration for 3 homogeneous synthetic rocks namely A1, A2 and A3, with different clay content ranging from 0 to 20% by weight. The clay mineral (montmorillonite) is uniformly distributed in the rocks. As the brine salinity decreases, there is a slight decrease in the permeability at higher brine salinities (e.g. above 50 grams/litre), while the rate of decrease rises dramatically at lower brine salinities with a limit of zero permeability when brine becomes very fresh. This figure also indicates that the effect of brine salinity on liquid absolute permeability becomes relatively more pronounced as the clay content increases. Fig.7.9 shows the effect of brine salinity on the liquid absolute permeability of 3 synthetic shaley rocks, namely A2 (montmorillonite), A8 (kaolinite) and A9 (illite), with the same clay content but different clay types. It is indicated by Fig.7.9 that the effect of brine salinity on the liquid absolute permeability of sample A2 is more significant compared with sample A8 and A9.
Fig. 7.8 Permeability vs. salinity for synthetic samples with different clay content.

Fig. 7.9 Permeability vs. salinity for synthetic samples with different clay type.
Table 7.2 List of Synthetic Samples for Permeability Test

<table>
<thead>
<tr>
<th>Core No.</th>
<th>Length cm</th>
<th>Diameter cm</th>
<th>Clay Type</th>
<th>Clay Dist.</th>
<th>Clay Content % by weight</th>
<th>$k_L$ mD</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>7.454</td>
<td>3.567</td>
<td>Clay Free</td>
<td>--</td>
<td>0</td>
<td>467.26</td>
</tr>
<tr>
<td>A2</td>
<td>7.847</td>
<td>3.553</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>10</td>
<td>278.61</td>
</tr>
<tr>
<td>A3</td>
<td>6.990</td>
<td>3.475</td>
<td>Mont.</td>
<td>Dispersed</td>
<td>15</td>
<td>73.63</td>
</tr>
<tr>
<td>A8</td>
<td>6.740</td>
<td>3.420</td>
<td>Kaolinite</td>
<td>Dispersed</td>
<td>10</td>
<td>347.43</td>
</tr>
<tr>
<td>A9</td>
<td>6.330</td>
<td>3.600</td>
<td>Illite</td>
<td>Dispersed</td>
<td>15</td>
<td>301.38</td>
</tr>
<tr>
<td>A13</td>
<td>8.185</td>
<td>3.556</td>
<td>Mont.</td>
<td>Laminated*</td>
<td>15</td>
<td>167.54</td>
</tr>
<tr>
<td>A14</td>
<td>8.237</td>
<td>3.499</td>
<td>Mont.</td>
<td>Laminated**</td>
<td>15</td>
<td>85.23</td>
</tr>
</tbody>
</table>

* Shale layers are parallel to flow direction
** Shale layers are perpendicular to flow direction

The reason for above experimental observations is simply because that clay minerals swell when in contact with fresher brine solutions (Grim 1968). As a result of clay swelling, the pore space for fluid flow can be severely reduced, the tortuosity of flow path and the internal pore surface roughness may be increased so that the absolute permeability decreases. The more significant reduction of the permeability with decreasing brine salinity of shaley samples containing montmorillonite clay, which has a loose crystal structure, can be attributed to the much more significant swelling compared with kaolinite and illite.

As listed in Table 7.2, although both samples have the same clay content, the permeability of sample A13 is much higher than that of sample A14 since the shale layers in sample A13 are parallel to the flow direction whereas the shale layers of sample A14 are perpendicular to the flow direction. It may be suggested that for the laminated shales distributed along a certain direction other than parallel or perpendicular to the flow direction, the permeability lies in between the above two extreme cases.
7.5 Conclusions

The following conclusions can be drawn based on the studies in this chapter:

a. The brine absolute permeability of rocks decreases with increasing confining pressure as a result of rock deformation which reduces pore size and increases pore tortuosity and pore surface roughness. The rate of permeability decrease is more significant at lower pressure range than that at higher pressure range. The pressure effect on the absolute permeability of less porous and less permeable rocks is more pronounced.

b. There is a decrease in brine absolute permeability with temperature increase for the rocks tested. This decrease in permeability may be attributed to the thermal expansion of rock forming materials which reduces pore size and, perhaps more importantly, increases pore tortuosity and pore roughness. The possible rock/fluid interaction stimulated by heating may also contribute to the reduction in brine absolute permeability.

c. The presence of clay minerals affects the brine absolute permeability of rocks especially at some low brine salinities (e.g. below 50 grams/litre). Rocks containing montmorillonite show more significant reduction in permeability than those containing kaolinite or illite at a given brine salinity level. Not only the clay content but also the clay distribution influences brine absolute permeability of shaley rocks.

d. Finally, continuing research is needed to investigate the effect of clay minerals on the absolute permeability of various rocks at simulated reservoir conditions of pressure and temperature.

References


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CHAPTER 8

THREE DIMENSIONAL

PORE SPACE PETROPHYSICAL MODELLING
8.1 Introduction

The transport properties such as electrical conductivity and hydraulic permeability, reflect the geometry and topology of the network of microscopic flow channels in rocks. Therefore, in principle, they can be calculated by solving Navier-Stokes and Laplace's equations respectively in the pore space. This approach, however, is extremely difficult due to the complexity of the boundary conditions which must be imposed at the irregular pore-grain interface.

Instead of looking for an exact solution of the transport properties of rocks, attempts have been focused on searching for a way to simplify the complex irregular pore space into an equivalent uniform pore network which then can be mathematically treated. There are typically two types of approaches to study the rock transport properties using simplified equivalent pore space models, namely, analytical method and numerical method (or pore space network modelling).

Although several previous authors (e.g. see Doyen 1988) have successfully studied the transport properties of various rocks at room conditions using the analytical approach, the in situ rock transport properties and the effect of clay minerals on the electrical properties of shaley sands as observed in the experimental studies have not been considered.

Pore space network modelling has been proved to be a very helpful tool to study both the electrical and hydraulic properties of rocks mainly due to that the inter-connectivity of pores can be effectively simulated. The primary objective of using network models in this study is to interpret the experimental results obtained in order to gain a better understanding of how the transport properties are related to the pore structures of rocks. For a wide range of reservoir rocks, the network model can be used as a predictive tool to calculate the in situ rock petrophysical characteristics.

This chapter presents details of two 3D pore space network models: (1) "NETSIM" for simulating the effects of pressure and temperature on rock transport properties; and (2) "CLAY" for modelling the effect of clay minerals in general and the clay distribution in particular, on the electrical properties of shaley sands. Details of the numerical predictions of the experimental results for both the sandstone and synthetic rock samples are also presented and discussed.
8.2 Review of Previous Models

Network models have been extensively used in studying the immiscible capillary displacement (also known as capillary desaturation or simply capillary pressure). A good review has been given by Yale (1984) in this area. It may be concluded that, during the late development of network models, the notable deviations from Fatt's classic networks (Fatt 1956a, 1956b, 1956c and 1957) are the adoption of more realistic non-uniform pore elements such as the tube-nodal pore network similar to Owen's (1952), the consideration of miscible flow, the inclusion of multi-phase flow and the extension from 2D to 3D networks. The following review will be focused on the network modelling studies on the electrical conductivity and hydraulic permeability of rocks.

The "bundle of capillary tubes" model has been used to study the hydraulic and electrical properties of reservoir rocks by numerous authors. The flow paths of a porous medium are represented by a bundle of capillary tubes with actual length $L_e$. The following two relationships were proposed to calculate permeability and formation factor (Kozeny 1927, Carmen 1938, Archie 1941, Wyllie and Spanger 1952, Schopper 1966) based on this simple pore tube model:

$$k = \frac{r_k^2 \phi}{s_o(L_e/L)^2}$$  \hspace{1cm} (8.1.a)

$$F = \frac{L_e}{\phi}$$  \hspace{1cm} (8.1.b)

where $\frac{L_e}{\phi}$ is the tortuosity defined as the ratio of the length of the tortuous path over the length of the rock element. The main weakness of this simple "bundle of capillary tubes" model, however, is that there are no connections between adjacent tubes. Therefore, flow of fluid and electrical current is restricted to the single capillaries where the large pores carry the largest part of the total flow through the whole sample. Due to this limitation, the applications of the bundle of capillary tubes model are very limited.

Owen (1952) realised that the high tortuosities found using equation (8.1.b) were unrealistic and devised an alternative concept of the pore space. The new
model consisted of voids connected to one another via smaller pore tubes as shown in Figs.8.1.a and 8.1.b. Owen concluded that the pore tubes contribute more to the conductivity of the porous medium than the node pores. He further suggested that large formation factor / porosity ratios can be obtained without the use of high tortuosity.

Two-dimensional models have been used more frequently than 1D and 3D pore space models due to the consideration of cross flow within pore networks and the simplicity in flow calculations. Fatt (1956a, 1956b, 1956c) constructed 2D networks with cylindrical tubes as the flow elements. Fig.8.2 shows three different forms of networks given by Fatt. The network of tubes has obvious advantage in comparison with the bundle of tubes. The inter-connectivity between tubes and the isotropic characteristic enable the models move one step further towards the reality of the complex pore space of consolidated sandstones. Although sphere pack models (Kozeny 1927, Carman 1938) describe the pore space of rocks more closely, the replacement with idealised cylindrical pore tubes simplifies the flow calculations. Using 2D networks, Fatt calculated the permeability and capillary characteristics of rocks. The tubes were randomly assigned in networks from given radius distributions.

A theoretical investigation on the formation factor, permeability and porosity relationship was presented by Schopper (1966) using a network model. The schematic drawing of a section of an unconsolidated porous media is shown in Fig.8.3. The numerical solution given by Schopper shows that the product of the formation factor and permeability can be expressed in expectation values, a pore shape factor and a network factor that depends on the mech texture of the networks.

Dullien's model (1976) was constructed from sets of small networks added together. The cross sectional size of capillaries varies along the tube as shown in Fig.8.4. Based on the network model, the permeability and formation factor were calculated from simple statistical equations. Dullien, however, conceded that the lack of full connectivity in the model leads to problems especially in calculating the capillary characteristics.

It is evident from Dullien (1976) and Seeburger and Nur's (1984) flow maps that much of the flow is through individual channels in 2D networks. However, Kirkpatrick (1973) and Larson et al. (1977) showed that conduction of fluids and
Fig. 8.1 Representation of pore space as nodes and tubes (Owen 1952).
Fig. 8.2 Three different forms of 2D networks (Fatt 1956).

Fig. 8.3 Schematic drawing of a cross-section of a porous model (Schopper 1966).
current in 3D models is via clusters of adjacent pores. Therefore, 3D network models are more realistic compared with 2D models in simulating the real characteristics of flow in porous sedimentary rocks. More recently, Yale (1984) has reviewed many published pore space models and simulated the flow, storage and deformation in porous rocks based on a 3D regular model constructed with grain boundary pores formed by the closest pack of four grains and spherical nodal pores. The lattice of the network is regular with a coordination number of 6 as shown in Fig. 8.5. The basic pore element, shown in Fig. 8.6, consists of a nodal pore and a pore tube with GBP shape. Due to the non-uniform nature of Yale's network model, i.e. it was constructed by small pore tubes connected with large spherical nodes, it may be used to simulate the pressure dependence rock transport properties more closely than many other previously reported network models.

It is concluded, therefore, that network modelling has been used successfully in the past to simulate the transport properties of rocks at room conditions. Three-dimensional networks are more suitable to model flow characteristics in rocks than 2D models because of the extra degree of inter-connectivity of pore tubes. To simulate the pressure dependence rock transport properties, 3D non-uniform pore space networks should be used. So far, no attempt has been reported to simulate the effect of temperature on the transport properties of sedimentary rocks and the effect of clay minerals on the electrical conductivity of shaley sands using network models. Therefore this study considers not only the pressure dependence rock transport properties, but also the temperature dependence rock transport properties and the effect of clay minerals in general and clay distribution in particular on shaley sand conductivity.

8.3 Modelling the Effect of Pressure and Temperature

In previous chapters, the experimental results of the electrical and hydraulic properties of sandstone and synthetic rocks at elevated pressures and temperatures have been reported. The mechanisms of the effects of pressure, temperature and clay, however, are not yet clear based on the experimental data only.

Therefore a 3D computer code (NETSIM) has been prepared in FORTRAN 77 to interpret and predict the experimental observations of pressure and temperature effect on the transport properties of rocks.
Fig. 8.4 Unit capillary of a non-uniform network model (Dullien 1976).

Fig. 8.5 3D regular lattice of the network model (NETSIM). (after Yale 1984).
Fig. 8.6 Cubic close packing of spheres and the hydraulic and electrical equivalent (Yale 1984).
A better understanding of the mechanisms of the experimental observations has been achieved based on the simulation study. The effects of pore size, pore shape and pore coordination number (or pore connectivity) which is defined as the average number of pore tubes connected to one pore node, on the rock properties at both atmospheric and elevated pressures have been numerically studied. In addition to the confining pressure effect, this 3D pore space petrophysical model simulates the temperature effect.

8.3.1 Description of the Model (NETSIM)

The 3D network model (NETSIM) can be used to simulate the following properties of porous sedimentary rocks:

1. porosity $\phi$,
2. formation resistivity factor $F$,
3. permeability $k$,
4. porosity change with confining pressure $\phi(P)$,
5. resistivity change with confining pressure $F(P)$,
6. permeability change with confining pressure $k(P)$,
7. porosity change with temperature $\phi(T)$,
8. resistivity change with temperature $F(T)$,
9. permeability change with temperature $k(T)$.

The following sections describe the details of the simulator (NETSIM) developed in this study.

(a) Elements in the Model

The petrophysical model is constructed by sphere nodal pores which are connected with each other by smaller pore tubes. The lattice is the same as Yale's model shown in Fig.8.5, but with a pore coordination number, defined as the number of pore tubes connected to one pore node, of $\leq 6$. Three different shapes (elliptical, tapered and grain boundary pore, GBP) as described in Fig.8.7 are employed in the model for comparison. The GBP pore shape is formed by three closely packed grains.
Fig. 8.7 Three pore shapes used in the network model (NETSIM).
(b) Flow and Storage Equations

The electrical resistance of a pore tube with any cross-section is given by:

\[ R_e = \frac{R_w l}{A} \]  

(8.2)

where \( R_w \) is the resistivity of the pore fluid, \( l \) is the length of the pore tube and \( A \) is the area of the cross-section of the tubes. For the nodal pores, the change in the area of the conductor going from tube to node is considered. The electrical resistance equation for the nodal pore given by Yale (1984) is:

\[ R_e = \frac{R_w}{\pi} \left( \frac{1}{r_e} - \frac{1}{S} \right) \]  

(8.3)

where \( S \) is the radius of the spherical nodes and \( r_e \) is the equivalent electrical radius of the pore tube connected to nodal pores, which is defined as the radius of a cylindrical tube with the same electrical resistance as the pore tube. The validity of equation (8.3) has been shown experimentally by Owen (1952).

For fluid flow through pipes, the cross-section shape has been taken into consideration. The simplest pore tube shape is a cylinder of circular cross section where the hydraulic resistance can be calculated from Hagen-Pouiselle pipe flow:

\[ Q = \frac{\pi P r^4}{8 \mu l} \]  

(8.4)

where \( Q \) is the volumetric flow rate, \( P \) is the pressure drop, \( l \) is the pore length, \( r \) is the pore radius and \( \mu \) is the viscosity of the pore fluid. The hydraulic resistance is defined as:

\[ R_h = \frac{P}{Q} = \frac{8 \mu l}{\pi r^4} \]  

(8.5)

The volumetric flow rate \( Q \) through a conduit of elliptic cross section is (Lamb, 1932):
where \( b \) and \( c \) are half width and half length of the cross section. The hydraulic resistance for elliptic pore is as follows:

\[
R_h = \frac{P}{Q} = \frac{4\mu(b^2 + c^2)}{\pi b^3 c^3}
\]  

(8.7)

For a tapered crack with half width \( b \) and half length \( c \), the flow calculation is:

\[
Q = \frac{\pi Pb^3(0.75c)^3}{4\mu(b^2 + (0.75c)^2)}
\]  

(8.8)

Similarly, the hydraulic resistance is expressed as:

\[
R_h = \frac{P}{Q} = \frac{4\mu(b^2 + (0.75c)^2)}{\pi b^3(0.75c)^3}
\]  

(8.9)

For the GBP shape, no simple analytical solution for the hydraulic conductance exists. In order to calculate the hydraulic resistance \( (R_h) \), a numerical approximation using finite difference grid has been obtained by solving a dimensionless Poisson's equation across a unit cross-section of a pore tube with no-slip boundary conditions. The solution to the Poisson's equation gives the fluid velocity at all points in the cross-section perpendicular to the flow direction. This velocity profile is then integrated to find the flux through the cross-section and by integrating the flux in the direction of the pressure gradient, the hydraulic resistance is calculated. The flow equation becomes:

\[
Q = \frac{P\pi r_{he}^4}{8\mu l}
\]  

(8.10)

where \( r_{he} \) is the radius of a cylinder with the same hydraulic resistance as the GBP pore. Thus, the hydraulic resistance for GBP is:
Since the nodal pores in the model are taken as spherical voids, Koplik's (1981a, 1981b, 1982) flow equation can be used. The pressure drop across half a nodal pore due to incoming fluid at rate $Q$ from a pore tube of hydraulic radius $r_{he}$ is as follows:

$$Q = \frac{\pi P r_{he}^4}{8\mu} \quad (8.12)$$

Therefore, the hydraulic resistance is as follows:

$$R_h = \frac{8\mu}{\pi r_{he}^4} \quad (8.13)$$

(c) Rock Deformation under Confining Pressures

To calculate the change of hydraulic resistance with confining pressure, rock pore deformations are first found using elastic theory. According to Berg (1965), the length of a thin elliptical crack is unaffected by hydrostatic stress applied to the surrounding solid, whereas the half width varies:

$$b(P) = b[1 - \frac{2Pc(1 - \nu^2)}{bE}]; \quad c(P) = c \quad (8.14)$$

where $b(P)$ and $c(P)$ are the width and length of the cross section under pressure, $E$ and $\nu$ are Young’s modulus and Poisson’s ratio.

For a tapered pore, Mavko and Nur (1978) found that both the width $b$ and the length $c$ change with an applied confining pressure:

$$b(P) = b\left[1 - \frac{4Pc(1 - \nu^2)}{3bE}\right]^\frac{3}{2} \quad (8.15)$$
Hertz contact theory (Timoshenko and Goodier 1972) is employed to calculate the deformation of GBP pores under confining pressure. Since the radius of the grains may be different from each other, the Hertz equations can thus be modified and normalized to:

\[
\frac{\alpha'}{r^*} = \left[ \frac{R^*}{r^*} \right]^\frac{1}{3} \left[ \frac{3\sqrt{2}P(1 - \nu^2)}{4E} \right]^{\frac{1}{6}} \quad [Yale(1984)] \tag{8.17}
\]

\[
\frac{\beta'}{r^*} = \left[ \frac{r^*}{R^*} \right]^\frac{1}{3} \left[ \frac{3\sqrt{2}P(1 - \nu^2)}{4E} \right]^{\frac{1}{6}} \quad [Yale(1984)] \tag{8.18}
\]

where \(\alpha'\) is the radius of contact, \(\beta'\) is the displacement of the centres of the two grains in contact, \(r^*\) is the average radius of grains, and \(R^*\) is the radius of curvature at contact point. Since the radius of the grains can be different from the radius of curvature at the point of contact of the grains, a family of shapes can be generated where the thinner (high \(\frac{R^*}{r^*}\) or \(RC\) ratio) pore shapes deform more for a given pressure. It is assumed that, during the calculation of hydraulic resistance of GBP pores after deformations, only pore size difference affects \(R_h\), while the effect of pore shape change due to the confining pressure is negligible.

(d) Thermal Expansion and Thermal Induced Cracking

There is not enough reliable information available in the literature on the thermal expansivity of rock forming materials at low to moderate temperatures (e.g. < 200 °C). According to Somerton and Selim (1961), there are about 0.8% to 0.9% expansions in bulk volume for samples of Berea and Boise sandstones respectively with a temperature increase from ambient to 200 °C. This study shows that there are about 0.3% to 0.8% expansions in total rock forming materials for the sandstones (as listed in Appendix C) with a temperature increase from ambient to 130 °C. The degree of thermal expansions for different rocks varies depending on their mineral compositions and pore configurations.
Thermal expansions of rocks under a confining pressure lead to decrease in porosity. As a result, accumulative thermal effects result in the decreasing in the sizes of flow paths and the possible increasing in the flow tortuosity and internal pore roughness, and therefore a decrease in electrical conductivity and hydraulic permeability. In this simulation study, the thermal expansion effects are accounted for by reducing proportionally all the pore element sizes (nodes and tubes) with an increase in temperature. The experimentally measured total porosity decreases of rocks against temperature are used in the network model as input data.

Due to differential and incompatible thermal expansion (or contraction) between grains with different thermoelastic moduli or between similar, but mis-aligned anisotropic grains, microcracking may be induced above certain temperatures (Kranz 1983) (e.g. 70° – 75°C for granite, and 200°C for quartzite). The numbers and characteristics of thermally induced microcracks depend on the value of absolute temperature, the heating or cooling rate and consequently induced thermal gradients, the thermal history and the mineralogy. In addition of inducing new microcracks, heating or cooling may also increase the sizes of pre-existing cracks or cracks formed at lower temperatures (Sprunt and Brace 1974). Although the effect of thermally induced microcracking on the transport properties of these rocks tested in this study may not be significant as the maximum temperature is only around 150°C in the experiments, it is still considered by opening some "dead pores" which have infinite electrical and hydraulic resistances initially. The opening of more pore tubes results in the increase of the average pore coordination number or pore connectivity, and consequently the increase of electrical conductivity and permeability.

Sanyal (1972) reported that the reduction in pore volume with temperature is not sufficient to cause the observed changes in formation conductivity. There is also a change in pore constriction during heating. In this modelling study, the effect of changes in pore constrictions with both confining pressure and temperature on the rock transport properties will be demonstrated and discussed.

(e) Network Simulation

Although the porosity depends on summation of single pore effects, the electrical and hydraulic transport properties are found by solving a set of simultaneous equations which relate the network flow properties to those of individual pore el-
lements. Using an electric analog, the voltage drop $V$ across a given pore element with resistance $R_e$, for a current of $I$ is:

$$V = R_e \cdot I$$  \hspace{1cm} (8.18)

Using the Hagen-Pouiselle equation for fluid flow, the pressure drop $P$, across any given pore element with hydraulic resistance $R_h$, for a volumetric flow rate of $Q$ is:

$$P = R_h \cdot Q$$  \hspace{1cm} (8.19)

Kirchoff’s circuit law states that there is no accumulation of charge at any node in the network:

$$\sum_{n=1}^{6} I_i = 0$$  \hspace{1cm} (8.20)

Similarly the mass balance equation for fluid is:

$$\sum_{n=1}^{6} Q_i = 0$$  \hspace{1cm} (8.21)

where $I_i$ and $Q_i$ are current and flow rate from connected tubes towards the node.

In the experimental rig the potential and pressure are known for the boundaries in contact with the electrodes and the fluid ports. No flow boundaries are imposed in the direction perpendicular to the average potential gradient. Pore tube parameters such as the size and aspect ratio are generated from given functions such as normal, log-normal and rectangular distribution. Each pore parameter from the distribution is then assigned to a particular pore randomly using a random number generator.

The main iteration routines in NETSIM to obtain new values of voltage and hydraulic potential, $V_{i,j,k}$ and $P_{i,j,k}$, are listed as follows:
\[ V_{i,j,k} = \frac{V_{i-1,j,k}}{R_{e_{i-1,j,k}}} + \frac{V_{i+1,j,k}}{R_{e_{i+1,j,k}}} + \frac{V_{i,j-1,k}}{R_{e_{i,j-1,k}}} + \frac{V_{i,j+1,k}}{R_{e_{i,j+1,k}}} + \frac{V_{i,k-1}}{R_{e_{i,k-1}}} + \frac{V_{i,k+1}}{R_{e_{i,k+1}}} \] (8.22)

and,

\[ P_{i,j,k} = \frac{P_{i-1,j,k}}{R_{h_{i-1,j,k}}} + \frac{P_{i+1,j,k}}{R_{h_{i+1,j,k}}} + \frac{P_{i,j-1,k}}{R_{h_{i,j-1,k}}} + \frac{P_{i,j+1,k}}{R_{h_{i,j+1,k}}} + \frac{P_{i,k-1}}{R_{h_{i,k-1}}} + \frac{P_{i,k+1}}{R_{h_{i,k+1}}} \] (8.23)

The numerical solutions (see the flow chart in Appendix E) of the resistivity and permeability start with initial estimates of pressure and voltage values. Then, new values are calculated using the successive overrelaxation method proposed by Young (1954, 1971). In order to gain a rapid convergence, a relaxation factor between 1.8 and 1.9 is used, and all the known new values are used immediately for the next calculation.

Simulations have been carried out for different sizes of networks up to a maximum size of 20 x 20 x 20 pore nodes with 25200 total pore elements in order to find the most suitable network size (i.e. the smallest network which gives output values of rock properties within an accepted accuracy range) to simulate the experimental results. The total number of pore elements (nodes + tubes) for a network with \( N_x \times N_y \times N_z \) nodes can be calculated as \( 3N_x \cdot N_y \cdot N_z + N_x \cdot N_y + N_x \cdot N_z + N_y \cdot N_z \). There is a 30% difference in resistivity and permeability between the 5 x 5 x 5 and the 10 x 10 x 10 networks and < 5% difference between the 10 x 10 x 10 and the 20 x 20 x 20 networks. Above 15 x 15 x 15, permeability and resistivity become independent of the network size.

Although the distribution of pore parameters remains the same with different random seeds, the placement of pores with a particular value is different. As random seeds vary, the 15 x 15 x 15 networks give very consistent results with less than 1% standard deviation in conductivity among the runs. While the 10 x 10 x 10 networks give larger standard deviation and the 20 x 20 x 20 networks give much smaller standard deviation among the results. It is also noticed that the computer time increases dramatically with the number of nodes in the network. Therefore the size of networks for modelling the experimental results is fixed at 15 x 15 x 15 pore nodes.
The computing work was performed on the Apollo 10000 work station at Mineral Resources Engineering Department, Imperial College.

8.3.2 Numerical Experiments

There are following 5 adjustable parameters in the model, i.e., (1) nodal pore radius $S$, (2) pore tube shape, (3) pore aspect ratio ($ASPR$) and its distribution for elliptic and tapered pores or pore geometric factor $RC$ for GBP pores, (4) pore size distribution and (5) average coordination number or pore connectivity. Since the porosity and pore size distribution are given for a particular rock, only one variable from pore tube length ($l$) and nodal pore radius ($S$) is needed in the model while another can be calculated. Numerical experiments have been carried out to investigate the effect of the variation of pore tube length ($l$) and nodal pore radius ($S$) on the transport properties of rocks. It has been concluded that the same value of $l$ and $S$ may be used for all pore tubes and nodal pores respectively to simplify the calculation. Before modelling the experimental results of sandstones, a systematic numerical study has been carried out to investigate quantitatively the effects of pore shape, pore size distribution, pore aspect ratio distribution, and average pore coordination number on the electrical and hydraulic properties of rocks at elevated pressures.

(a) The Effect of Pore Shape

The effect of pore shape on rock petrophysical properties at high pressures has been simulated. Fig.8.8 shows that although the initial porosity values are the same for three types of pores, the porosity changes with confining pressure are different. Similarly the conductivity and permeability also change with confining pressure differently as indicated in Fig.8.9 and Fig.8.10. For the idealised pore shapes like the elliptic and the tapered, a very small aspect ratio $ASPR$, which is defined as the ratio of half width over the half length of a cross section, is needed to correctly simulate the pressure dependent flow and storage properties. However, if a small $ASPR$ of less than 0.005 is used, the absolute permeability value is always less than a few milli-darcies. Therefore both elliptic and tapered pore tubes cannot be used to model the transport properties of sandstone rocks which have higher permeabilities.
Fig. 8.8 Porosity vs. confining pressure showing the effect of pore shape.

Fig. 8.9 Conductivity vs. confining pressure showing the effect of pore shape.

Fig. 8.10 Permeability vs. confining pressure showing the effect of pore shape.
(b) The Effect of Pore Size Distribution

The pore size of rocks controls the absolute value of electrical conductivity and hydraulic permeability. As the percentage of large pores increases, large pores dominate the flow, and the chance of connecting large pores increases. For a given average pore size, how the pore size distribution affects the rock transport properties, however, is not yet quantified. Fig. 8.11 illustrates the normalized rock conductivity and permeability against the standard deviation (SD) of pore sizes following a normal distribution. At a given mean pore size of 5 \( \mu m \) and porosity of 14%, normalized conductivity and permeability of rocks decrease with an increase in the standard deviation of pore sizes. Since the electrical current flow and the fluid flow in rocks follow different patterns, the effect of \( SD \) of pore sizes on electrical conductivity differs from that on the permeability as shown in Fig. 8.11.

(c) The Effect of Pore Aspect Ratio

This section deals quantitatively with the effect of pore aspect ratio on rock transport properties based on the study of a network model consisting of elliptic pores. As shown in Fig. 8.12, permeability increases linearly with pore aspect ratio while conductivity and porosity remain constant. For a given mean pore aspect ratio and porosity (e.g. 0.05 as shown in Fig. 8.12), permeability decreases with the increase in standard deviation of pore aspect ratio while conductivity remains unchanged. Figs. 8.13 - 8.15 show the change of normalized porosity, conductivity and permeability with confining pressure for models with various average pore aspect ratios ranging from 0.1 to 0.001. It is confirmed numerically that a very small value (e.g. < 0.005) of pore aspect ratio is needed to simulate the curved trend of rock porosity, conductivity and permeability at various confining pressures. At a given pore aspect ratio, the decrease in permeability with pressure is most significant while the decrease in porosity with pressure is least significant with conductivity change with pressure lies in between these two extremes. Finally, as shown in Fig. 8.16, permeability also depends on the standard deviation of the pore aspect ratio while porosity and conductivity do not.
Fig. 8.11 Normalized conductivity and permeability vs. standard deviation of pore sizes following a normal distribution.

Fig. 8.12 Porosity, conductivity and permeability vs. pore aspect ratio.
Fig. 8.13 Normalized porosity vs. confining pressure for elliptic pores with different average pore aspect ratio.

Fig. 8.14 Normalized conductivity vs. confining pressure for elliptic pores with different average pore aspect ratio.
Fig. 8.15 Normalized permeability vs. confining pressure for elliptic pores with different average pore aspect ratio.

Fig. 8.16 Normalized conductivity and permeability vs. the standard deviation of pore aspect ratio.
(d) The Effect of Coordination Number

For a 3D network with regular lattice, the coordination number, which is defined as total number of tubes connected to one node, is 6 if all branches are connected. If some conducting branches (pore tubes) are removed, the degree of interconnectedness between pores is reduced and consequently the transport properties are also reduced. To represent the degree of interconnectedness of pores, a concept of average coordination number (ACN) for a model with some pore branches randomly removed is defined here as a function of pore tube / pore nodes ratio. The ACN of a network with broken branches (or dead pores) can be calculated by the following equation:

\[
ACN = \frac{NT + 3Nx \cdot Ny \cdot Nz - Nx \cdot Ny - Nx \cdot Nz - Ny \cdot Nz}{Nx \cdot Ny \cdot Nz}
\]  

where \(NT\) is the total number of unbroken branches, \(Nx, Ny, Nz\) are the total number of nodes in x, y and z directions.

Fig. 8.17 shows normalized conductivity and permeability against ACN of a network with 10 x 10 x 1 size. Both conductivity and permeability decreases with a decrease in ACN and approach zero when ACN decreases to below 4.6 where there is almost no continuous path for current and fluid flow through the whole network. Fig. 8.18 shows normalized conductivity and permeability plotted against the fraction of dead pores (or removed pores). As the total number of dead pores increases, conductivity and permeability of the network decrease accordingly until a certain critical point after 33% pore branches disappeared when the electrical and hydraulic resistance across the network become infinite. The above numerical experiment demonstrates the percolation theory (Sykes and Essam 1964 and Shante and Kirkpatrick 1971) which suggests that there is a critical fraction of branches or bonds that must exist before the probability of a complete connection across a large cluster of such bonds is finite.

8.3.3 Experimental Data Modelling

In this section, some experimental data obtained from various rock samples will be numerically simulated in order to understand the mechanisms of how pres-
Fig. 8.17 Normalized conductivity and permeability vs. coordination number.

Fig. 8.18 Normalized conductivity and permeability vs. fraction of dead pores demonstrating the percolation theory.
sure and temperature influence the electrical and hydraulic properties of rocks. Experimental data (in points) are compared with numerical predictions (in lines).

The initial input data to the simulator include network size, rock porosity, pore shape, pore aspect ratio or $RC$ ratio distribution, pore size distribution, nodal pore radius and pore connectivity ($ACN$). To simulate pressure effects, two elastic constants are given, i.e., Young's modulus ($E$) and Poisson's ratio ($\nu$). To simulate temperature effects on the rock transport properties, total volumetric expansion of rock matrix is needed. The output results from the simulator include the absolute values of electrical resistivity factor and permeability at room conditions and the normalized resistivity and permeability at elevated pressures and temperatures. The simulation output is then compared with the experimental results. The input variables to the simulator may be adjusted and the simulation is carried out under the new input conditions until finally a good agreement between modelling and experimental results is obtained.

(a) Pressure Effect

As confining pressure increases, the increase in rock electrical properties is caused by the pore volume deformation and the pore constriction effect. In other words, if Archie's equation ($F = \frac{1}{\phi^m}$) is used, both porosity ($\phi$) and cementation factor (m) vary with pressure. From Fig.8.19 to Fig.8.22, the comparison of experimental data with numerical results is given for four different sandstone rock samples, namely S1, S2, S3 and S4. In these graphs, normalized porosity ($\phi$), formation factor ($\frac{1}{F}$), Archie cementation factor (m) and permeability ($k$) are plotted against the confining pressure. The initial absolute values of porosity, conductivity and permeability at atmospheric conditions are given in these diagrams. For the 4 sandstones, there is a good agreement between the model predictions and the experimental results. Table 8.1 lists the parameters in the simulation for the 4 samples.

To explain why resistivity increases with pressure more than can be accounted for by porosity reduction, simulations have been carried out by changing the sizes of the nodal pores. As the size of the nodal pores is reduced, the difference between $F$ increasing and porosity decreasing becomes smaller. In an extreme case when the nodal pores disappear or the whole model only consists of uniform tubes, both resistivity and porosity change with pressure in the same way and cementation
Fig. 8.19 Numerical predictions vs. experimental results for S1 showing the effect of confining pressure.

Fig. 8.20 Numerical predictions vs. experimental results for S2 showing the effect of confining pressure.
Fig. 8.21 Numerical predictions vs. experimental results for S3 showing the effect of confining pressure.

Fig. 8.22 Numerical predictions vs. experimental results for S4 showing the effect of confining pressure.
factor remains constant. Therefore, it can be predicted that if a rock sample has uniform pores or non-uniform pores but they deform in the same manner under a confining pressure, such that there is not any pore constriction, then the F and porosity change by the same amount and the cementation factor remains independent of pressure.

Some authors have claimed that the changes of Archie cementation factor with pressure is partly due to permanent structure changes such as collapses of cementing materials. However, such a significant permanent change of rock structures has not been observed in this work. This study suggests from both experiment and numerical simulation that the changes of F with pressure are due to the rock deformations and changes of pore constrictions. The change in Archie cementation factor $m$ with confining pressure is an accumulative result of pore constriction changes (Jing et al. 1989).

Other experimental observations such as more rapid increase of F and $m$ at low pressures and greater effects of pressure on F and $m$ for less porous and less permeable rocks have also been simulated. Firstly, to model the more rapid decrease of porosity under lower pressures simultaneously leads to more rapid change of pore constriction and therefore more rapid change of $m$ and F. Secondly,

<table>
<thead>
<tr>
<th>Table 8.1 : List of Network Parameters</th>
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<tr>
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<tr>
<td>Pore Length, $l$</td>
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<tr>
<td>Nodal Radius, $S$</td>
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<tr>
<td>Pore Shape</td>
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<tr>
<td>$RC$ Ratio</td>
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<tr>
<td>$ACN$</td>
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<td>Min. and Max.</td>
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* The length and radius unit is in um

** Rectangular distribution
to reproduce the experimental results of porosity decrease with pressure for less porous, less permeable rocks using the network model automatically results in greater increases of \( m \) and \( F \). The reason why \( F \) and \( m \) change more rapidly with pressure in less porous, less permeable rocks is because of the greater increase of pore constrictions with pressure.

Simulations have been carried out to provide an explanation of why the permeability of rocks decreases more with confining pressure than the conductivity and porosity. Since the hydraulic conductance of a pore tube with radius of \( r \) is proportional to \( [r^4] \) as stated by equation (8.5) while the electrical conductance and pore volume of the same pore is only proportional to \( [r^2] \), a certain decrease in \( r \) results in more significant decrease in permeability. In addition, since permeability depends not only on the pore size but also on the pore shape, the change in the pore cross-sectional shape caused by pore deformation may also contribute to the decrease in the permeability (Jing et al. 1990 a). Simulation shows that for the network with cylindrical pore tubes, the effect of confining pressure on porosity, conductivity and permeability is nearly the same within a pressure range from 0 to 35 MPa due to the very small pore volume deformations. As the aspect ratio for elliptic and tapered pores decreases, or the \( RC \) ratio for GBP pores increases, the pore volume deformation increases as stated by equations 8.14 - 8.18, therefore, the permeability vs. confining pressure curve deviates from the conductivity and porosity curves.

(b) Temperature Effect

The effect of temperature on porosity, conductivity and permeability has been numerically simulated by NETSIM. The experimentally determined rock matrix expansion data are input to the simulator to account for the effect of temperature. As temperature increases, the sizes of all the pore elements (tubes + nodes) are assumed to be decreasing proportionally by a same factor. There is a good agreement between the experimental data and the modelling results, shown in Figs.8.23 and 8.24, at lower temperature range (i.e. \(< 80 \, ^\circ C\)) for sample S1 and S3. At higher temperatures, the numerical results seem to under- estimate the effect of temperature on the electrical conductivity and permeability.

In the lower temperature range, the decrease in conductivity and permeability with temperature can be attributed to the thermal expansion of rock forming
Fig. 8.23 Numerical predictions vs. experimental results for S1 showing the effect of temperature.

Fig. 8.24 Numerical predictions vs. experimental results for S3 showing the effect of temperature.
materials which reduces the pore sizes and increases the pore constrictions. At higher temperatures, the more dramatic decrease of conductivity and permeability than can be accounted for by the reduction in the pore sizes may be attributed to the closure of small pores and the non-uniform expansion of rock forming materials.

The increase in conductivity and permeability with temperature possibly resulted from micro-cracking, as reported by some previous authors, has been numerically simulated by opening some new flow paths to increase the ACN or the pore connectivity. The simulation results show that up to 50% increase in conductivity and permeability with temperature can be created if the ACN increases from 5.4 to 6.0 for some rocks. The hysteresis observed for some samples in the temperature experiments, e.g., the conductivity measured in the cooling cycle is higher than that measured in the heating cycle, can also be attributed to the thermal induced micro-cracks which increase the pore connectivity.

8.4 Modelling the Effect of Clay on Shaley Sand Conductivity

In Chapter 6, the effect of clay on shaley sand conductivity has been experimentally determined. An improved Waxman-Smits shaley sand model was proposed by including a temperature coefficient ($\omega$) and a clay distribution coefficient ($\tau$). The value of $\omega$ as a function of temperature and clay content has been experimentally measured (Jing 1990). The value of the distribution coefficient $\tau$ for a given clay distribution mode, however, cannot be measured experimentally since there are so many possible clay distributions which may be encountered in reservoir rocks.

A 3D pore space network model (CLAY), therefore, has been developed to relate the clay distribution coefficient ($\tau$) to the computer generated stochastic clay distributions. This numerical model enables the practical application of the modified W-S model proposed previously in Chapter 6 (equations 6.4 and 6.6).

8.4.1 Description of the Model

(a) Elements in the Model

The model consists of inter-connected pore tubes as the basic conducting elements. Since the pressure dependent shaley sand conductivity is not included in this study, the size of nodes is at present given as zero. The lattice of the model
is regular with a coordination number of \( \leq 6 \). For a given pore size distribution function, a set of pore radii is generated for all pore tubes. The pore tube length is computed so that the rock porosity calculated agrees with the given porosity.

(b) Shaley Sand Conductivity Models

Two shaley sand conductivity models, *i.e.*, Waxman-Smits (Waxman and Smits 1968) and Dual-Water (Clavier *et al.* 1977, 1984), have been employed in the simulation study. The total bulk clay content \((Q_v)\) is distributed to each individual pore tube using rectangular, normal and log-normal mesh generators respectively. For each pore tube, the clay mineral \((Q_{v(i,j,k)})\) is assumed to be distributed uniformly around the pore space so that the excess conductivity of clay cations is parallel to the free brine solution conductivity, therefore, both W-S and D-W can be applied to calculate the equivalent solution conductivity \((C_{we(i,j,k)})\) which accounts for the accumulative conduction effect by free pore solution and the electrical double layer associated with clay.

The equivalent conductivity for a pore tube can be calculated by the W-S and the D-W respectively as follows:

\[
C_{we(i,j,k)} = C_w + BQ_{v(i,j,k)} \quad \text{(8.25)}
\]

\[
C_{we(i,j,k)} = (1 - \alpha vQ_{v(i,j,k)})C_w + \beta Q_{v(i,j,k)} \quad \text{(8.26)}
\]

The conductance or resistance of the pore tube can then be calculated by applying Ohm’s Law while considering the geometric factor of the tube. Other shaley sand conductivity models can be used in the simulator by adjusting the subroutine of \(C_{we(i,j,k)}\) calculations.

(c) Numerical Simulation

Once the values of \(C_{we(i,j,k)}\) for all the pore tubes are generated, the procedure of solving a set of simultaneous linear equations to obtain the electrical current for a given voltage is the same as in the case of NETSIM. The main iteration
routine is the same as stated by equation (8.22). Ohm’s Law is then applied to calculate the rock conductivity $C_o$ for a given model. As illustrated by the flow chart listed in Appendix E, a DO-LOOP is written in the simulator to repeat the $C_o$ calculation at different solution conductivities ($C_w$).

The input data to the simulator include porosity, pore size distribution, coordination number ($ACN$), bulk clay content ($Q_v$) and clay distribution function. In order to fit the experimental data of the $C_o$ vs. $C_w$ curves or the simple analytical modelling results by the W-S and D-W as mentioned previously, firstly, the pore size distribution and the co-ordination number are adjusted in order to obtain the correct slope (apparent formation factor according to W-S) of the simulated $C_o$ vs. $C_w$ curves; secondly the clay distribution function and the standard deviation of a given distribution may be adjusted to achieve the correct $C_o$ intercept. Since, as concluded earlier in Chapter 6, both the W-S and the D-W can be applied to interpret the conductivity of shaley sands containing uniformly dispersed clay with nearly the same accuracy, only the W-S is, therefore, chosen in the following sections to model the experimental results and to predict the value of clay distribution coefficient ($\tau$). The outputs from the simulator are $C_o$ vs. $C_w$ data and the simulation parameters including the pore size distribution, $ACN$ and clay distribution function.

8.4.2 Experimental Data Modelling

Four shaley sands with dispersed clays ($DOD = 1.0$), namely, A2, A3, A4 and A5 as described in Table 6.2, are chosen in the simulation study to provide the base line data. Figs.8.25 - 8.28 show the experimental data of $C_o$ vs. $C_w$ against the analytical model predictions by the W-S and the numerical simulation results. In modelling the experimental results for above 4 shaley sands, the $Q_{v(i,j,k)}$ for each individual pore tube is the same as the total bulk clay concentration ($Q_v$), which is actually one of the basic assumptions in the W-S, D-W and many other analytical shaley models. There is a good agreement between the simple analytical model predictions and the numerical results for the 4 shaley sands containing uniformly dispersed clay.
Fig. 8.25 $C_o$ vs. $C_w$ measured and predicted by the network model for A2.

Fig. 8.26 $C_o$ vs. $C_w$ measured and predicted by the network model for A3.
Fig. 8.27 $C_o$ vs. $C_w$ measured and predicted by the network model for A4.

Fig. 8.28 $C_o$ vs. $C_w$ measured and predicted by the network model for A5.
8.4.3 The Determination of Clay Distribution Coefficient ($\tau$)

Once the base line case, i.e., dispersed clay distribution where the degree of dispersion ($DOD$) equals 1, is fitted successfully, the next step is to consider the effect of the clay distribution modes (i.e., dispersed clay with $DOD \neq 1.0$, laminated and structural clay) on the shaley sand conductivities. The $DOD$ for dispersed clay and the degree of lamination ($DOL$) for laminated clay have been defined in Chapter 6 as the fraction of the clay volume per unit volume of reservoir rock. Fig.8.29 shows some computer generated clay distribution cases with dispersed and laminated clays (Jing 1990).

Numerical simulation has been carried out to quantify the distribution coefficient ($\tau$) for the dispersed clay with the same bulk $Q_v$ but with different $DOD$. Fig.8.30 shows the $C_o$ vs. $C_w$ curves for a particular rock containing dispersed clay with various $DOD$. Fig.8.31 gives the numerical results of the $\tau$ vs. $DOD$ for the shaley sands containing dispersed clay. The procedure of obtaining the value of $\tau$ for a given $DOD$ is as follows: (a) calculate the $C_o$ vs. $C_w$ curve for the case of the generated dispersed clay with $DOD \neq 1.0$, (b) re-run the same simulation model with $DOD = 1.0$, while changing the bulk $Q_v$ until a good fit between the two $C_o$ vs. $C_w$ outputs is achieved, (c) take the ratio of the bulk $Q_v$ from step (b) over that from step (a) as the distribution coefficient for the given $DOD$. The value of $\tau$ determined experimentally for sample A12 supports the numerical results. Similar to dispersed clays, the theoretical value of $\tau$ for structural clays ranges from 0 to 1.0 depending on the degree of local clay concentration. Although theoretically $DOD$ may be equal to 0, which means all clays are concentrated in one mathematical point and their effect on shaley sand conductivity becomes zero, practically there must be a lower limit above 0 of $DOD$ for a given bulk $Q_v$ because the interstitial pore spaces which accommodate the clay particles are limited. The higher the bulk $Q_v$, the higher will be the lower limit of $DOD$.

The procedure of calculating the distribution coefficient for laminated clays is similar to that for dispersed clay as described above. Only the results for continuous thin shale layers, i.e., degree of lamination ($DOL$) less than 0.3, are discussed here since their effect on the total rock conductivity is more significant than those of laminated shales with larger $DOL$. It is concluded that $DOL$ does not influence the value of $\tau$ significantly for these very thin shale cases concerned. The value of $\tau$ appears to be always around 1.4 for the sands containing laminated
Fig. 8.29 Cross-sections of 6 computer generated clay distribution cases (the legend shows the $Q_v$ distribution).
Fig. 8.30 $C_o$ vs. $C_w$ predicted by the network model for dispersed clays showing the effect of clay distribution.
Fig. 8.31 Simulation results of the correlation between the distribution coefficient (τ) and the degree of dispersion (DOD).

Fig. 8.32 Simulation results of the correlation between the distribution coefficient (τ) and the degree of lamination (DOL).
clay with the layers parallel to the conductive flow direction as shown in Fig. 8.32. The numerical results agree generally with the experimental results in the case of sample A13. For the cases of laminated clay with the layers perpendicular to the flow direction, the value of $\tau$ is always much less than 1.0 as confirmed experimentally by sample A14. For the laminated shales distributed along a certain direction other than parallel or perpendicular to the flow direction, the value of $\tau$ lies in between the above two extreme cases.

Finally, for a given clay distribution mode (i.e., laminated, dispersed or structural), the actual statistical distribution of clays (i.e., rectangular, normal or log-normal) also influences shaley sand conductivity, but with a second-order magnitude (Jing et al. 1990 b). Further research is needed to study the cases of mixed clay distributions and to generate stochastically discontinuous shales at the micro-scales. This will extend the current study to more general cases of laminated clay distributions. In work continuing after this thesis the computer model (CLAY) will also be applied to predict the effect of clay on the permeability of rocks for different clay type, content and distribution.

8.5 Conclusions

The following conclusions can be drawn based on this numerical study:

a. Two 3D pore space petrophysical models capable of predicting the effects of pressure, temperature and clay on the electrical and hydraulic properties of porous rocks have been developed.

b. A systematic numerical study has been provided to quantify the effect of pore shape, pore size distribution, pore aspect ratio distribution and pore coordination number on the pressure dependent rock transport properties. Both the effect of pressure and the effect of temperature on the electrical and hydraulic properties of sandstone rocks as determined experimentally and reported in previous chapters have been closely simulated. A contribution to the fundamental understanding of the mechanisms of how pressure and temperature influence the petrophysical properties of reservoir rocks has been achieved.

c. The pore constriction effect on rock transport properties is attributed to the
non-uniform deformations of individual pore tubes and the possible closure of small pores at elevated pressures and temperatures. The more dramatic change in permeability with pressure and temperature is attributed primarily to the facts that permeability is proportional to the \( r^4 \) while conductivity and porosity are only proportional to the \( r^2 \), where \( r \) is the pore radius. In addition, permeability depends on not only the pore tube cross-sectional area but also the pore shape.

d. The computer model (CLAY) allows the quantification of the clay distribution coefficient \( (\tau) \) for identified clay distribution modes. Therefore, this model enables the practical use of the improved W-S shaley sand conductivity model (equations 6.4 and 6.6) to enhance the accuracy of the estimation of in situ porosity and hydrocarbon saturation of shaley reservoir rocks.

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CHAPTER 9

CONCLUSIONS AND RECOMMENDATIONS
This chapter summarises the key conclusions of the thesis and provides some suggestions for further study.

This thesis presents a novel multi-sample high pressure and high temperature rock testing system and a new method for making synthetic shaley rock samples for the study of clay effect on shaley sand conductivity at reservoir conditions. Fifteen clay-free sandstone rocks have been tested in order to quantify both the individual and the combined effect of pressure and temperature on the electrical properties of porous rocks. The absolute permeabilities of 5 sandstone rocks have been measured at simulated reservoir conditions of pressure and temperature. To quantify the effect of clay on the electrical properties of shaley sands at elevated pressures and temperatures, 14 synthetic shaley sands have been made and tested. Finally, in order to interpret and predict the experimental observations and to gain an insight into the mechanisms of the effect of pressure, temperature and clay on the electrical and hydraulic properties, two 3D pore space network models have been developed. These two petrophysical models provide solutions to the complex problem of relating the rock petrophysical properties to their microscopic pore structures and clay distributions.

9.1 The New Experimental Techniques

A novel multi-sample high pressure and temperature rock testing system has been developed for experimental measurements of the electrical and hydraulic properties of a wide range of rocks. The use of this multi-sample system enables increase in the speed of rock testing and, since all 5 samples are placed in identical conditions, elimination of experimental comparison errors caused by the fluctuations of pressure and temperature.

A new technique for making synthetic shaley rock samples for the study of clay effects on shaley sand conductivity at both room and reservoir conditions has been developed. Clay minerals are used directly as cements to make synthetic samples with desired clay type, content and distribution mode. The clay content \( Q_y \) can be accurately determined. This technique of repeated loading-unloading and heating-cooling in principle simulates the physical process of sedimentation and compaction of natural sandstone rocks.
9.2 The Effect of Pressure and Temperature on the Electrical Properties of Sandstone Rocks

Significant increases in both formation factor and cementation factor with pressure and temperature have been observed for the 15 sandstone samples tested. The changes of the electrical properties of these clay-free sandstones with pressure and temperature are attributed to the changes in porosity and pore constrictions caused by rock deformations and rock matrix expansions. If the effect of pressure and temperature on Archie cementation factor \( m \) is ignored during the electrical log calibrations, up to 14% under-estimations of porosity of these sandstones tested can be found. The effect of pressure and temperature on the degree of under-estimations of rock porosity is found to be much more pronounced for the low porosity and low permeability rocks.

The combined effect of pressure and temperature on the electrical properties of these sandstone rocks tested is found to be approximately the sum of their individual effect.

9.3 The Effect of Pressure and Temperature on the Absolute Permeability of Rocks

Five sandstone and 7 synthetic rock samples have been measured at elevated pressures and temperatures. The brine absolute permeability of all the samples decreases with increasing confining pressure as a result of rock deformation which reduces pore size and increases pore tortuosity and pore surface roughness. The rate of permeability decrease is generally more significant at lower pressure range than that at higher pressure range. The pressure effect on the absolute permeability of less porous and permeable rocks is more pronounced than that of more porous and permeable rocks.

There is a significant decrease in brine absolute permeability with a temperature increase for the 5 sandstone rocks tested. This decrease in permeability may be attributed to the thermal expansion of rock forming materials which reduces pore size and, perhaps more importantly, increases pore tortuosity and pore roughness. The possible rock/fluid interaction stimulated by heating may also
contribute to the reduction in brine absolute permeability.

The presence of clay minerals affects the brine absolute permeability of rocks especially at some low brine salinities (e.g. below 50 grams/litre). Rocks containing montmorillonite show more significant reduction in permeability than those containing kaolinite or illite at a given brine salinity level.

Finally, not only the clay content but also the clay distribution modes (e.g., dispersed or laminated clays) influence the brine absolute permeability of shaley rocks. For laminated clay distribution, the orientation of the thin shale layers also influences the brine absolute permeability of shaley rocks.

9.4 The Effect of Hysteresis

Significant hysteresis has been observed in both pressure and temperature experiments. For a given rock, the hysteresis effect depends on the magnitude, the increment and the duration of applied pressure and temperature.

The hysteresis occurring during both pressure and temperature experiments suggests that not only the reservoir pressure and temperature conditions but also the history of the changes of pressure and temperature influence the formation resistivity, porosity and permeability. Comparing with the actual pressure and temperature effect on resistivity, porosity and permeability, however, the hysteresis effect is of second order magnitude.

9.5 The Effect of Clay on Shaley Sand Conductivity

A systematic experimental and theoretical study has been carried out to investigate the effect of clay on shaley sand conductivity at simulated reservoir conditions of pressure and temperature. Based on the experimental results of the 14 synthetic shaley samples, the total effect of temperature on the apparent formation factor and cementation factor of shaley sands has been found to be dependent on whether the thermal expansion effect or the excess clay conductivity dominates in a given rock. A critical clay content ($Q_v = 0.8 \text{ meq/cc}$), where the effect of thermal expansion is balanced by the clay excess conductivity, was found in this
Applying the Archie equations in the interpretation of shaley sand conductivity may lead to erroneous estimates of rock petrophysical properties because they do not consider the clay excess conductivity. Both over-estimate and underestimate of true rock conductivity are possible depending on whether the in situ brine conductivity is higher or lower than the pore fluid conductivity of the core samples tested in the laboratory.

The Patnode-Wyllie (P-W) model does not represent actual shaley rock conductivity relationships adequately because it assumes that the “conductive solids” conductivity is constant and independent of water conductivity. Therefore, the curvature of the \( C_o \) vs. \( C_w \) plots of shaley rocks cannot be modelled.

Both Waxman-Smits (W-S) and Dual-Water (D-W) shaley sand conductivity models may be applied for interpreting the electrical conductivities of the shaley sands containing uniformly dispersed clays \( (DOD = 1.0) \) at room temperatures. By selecting different values for the empirical constants in both models, the accuracy may be further improved for a particular shaley reservoir rock. Therefore, although the D-W model is theoretically more advanced, it gives nearly the same accuracy in modelling experimental results as W-S model because both models are based on the same initial over-simplified assumptions.

The W-S model has been modified by adding a temperature coefficient \( (\omega) \), which depends on the temperature and clay content, and a clay distribution coefficient \( (\tau) \) which is a function of clay distribution type and the volume fraction of clays per unit volume of rocks. The value of \( \omega \) for a given shaley sand at a given temperature has been determined experimentally. The value of \( \tau \) for a given clay distribution has been determined numerically based on a 3D computer model. The improved W-S models for both water and hydrocarbon bearing formations are as follows:

\[
C_o = \frac{1}{F_r} (\omega B \cdot \tau Q_v + C_w)
\]

\[
C_t = C_o S_{w}^\prime \frac{C_w + \omega B \cdot \tau Q_v}{C_w + \omega B \cdot \tau Q_v}
\]
It is proposed that the two equations above should be used instead of the original W-S model in the interpretation of \textit{in situ} shaley sand conductivities since they cover two more important aspects of the conductive behaviour of shaley sands. The apparent formation factor and cementation factor for shaley sands may increase or decrease with temperature depending on whether the thermal expansion or the clay excess conductivity dominates in a particular rock system. The shaley sand formation factor \((F')\) and cementation factor \((m')\), which do not include the effect of pore fluid salinity, increase with pressure and temperature. Therefore an Archie type equation between \(F'\) and \textit{in situ} shaley sand porosity exists:

\[
F' = \frac{1}{\phi m'}
\]

where the shaley sand cementation factor \(m'\) can be experimentally determined after accounting for the combined effect of pressure and temperature.

\*9.6 The 3D Pore Space Network Models\*

Two 3D pore space petrophysical models capable of predicting the effect of pressure, temperature and clay on the electrical and hydraulic properties of porous rocks have been developed. Based on the computer models, a systematic numerical study has been undertaken to quantify the effect of pore shape, pore size distribution, pore aspect ratio distribution and pore coordination number on the pressure dependent rock transport properties. Both the effect of pressure and temperature on the electrical and hydraulic properties of sandstone rocks determined experimentally has been closely simulated. An improved understanding of the fundamental mechanisms of how pressure and temperature influence the petrophysical properties of reservoir rocks has been achieved.

The effect of pore constrictions on rock transport properties is attributed to non-uniform deformations of individual pore tubes and the possible closure of small pores at elevated pressures and temperatures. The more dramatic change in permeability with pressure and temperature is attributed primarily to the facts that permeability is proportional to the \(r^4\) while conductivity and porosity are
only proportional to the $r^2$, where $r$ is the pore radius, and permeability depends not only on the pore tube cross-sectional area but also on the pore shape.

The computer model (CLAY) allows the quantification of the clay distribution coefficient ($\tau$) for any identified clay distribution modes. Therefore, this pore space petrophysical model enables the practical application of the improved W-S shaley sand conductivity models, proposed in this study, to enhance the accuracy of the estimation of in situ porosity and hydrocarbon saturation of shaley formations.

9.7 Suggestions for Further Work

This study has shown the significant effect of pressure, temperature and clay on the electrical and hydraulic properties for rocks fully saturated with brine. Further research will be directed towards the investigation of the effect of pressure, temperature and clay on the electrical and hydraulic properties of reservoir rocks containing both oil and saline water. The following areas are recommended for future experimental study using the multi-sample reservoir condition rock testing system:

a. The application of the improved Waxman-Smits shaley sand conductivity model in the oil bearing shaley sands at reservoir conditions of pressure and temperature.

b. The effect of pressure, temperature and wettability on the formation resistivity index and the saturation exponent of oil bearing clean (clay-free) rocks.

c. The relative permeability characteristics of reservoir rocks at simulated reservoir conditions with reference to the effect of wettability.

The future numerical study includes the extension of the two existing 3D petrophysical models to cover the effect of pressure, temperature and clay on the electrical and hydraulic properties of oil bearing reservoir rocks.
All electrical conductive materials correspond in their electrical behaviour to a combination of resistors and capacitors (series as shown in Fig.A.1.(a), parallel as shown Fig.A.1.(b), or a mixture of both resistor and capacitor (RC) circuit).

Consider a series RC circuit with an applied voltage:

\[ v(t) = v_0 \cdot e^{j\omega t} \]  \hspace{1cm} (A.1)

where \( v_0 \) is the amplitude of the voltage, \( t \) is the time, \( \omega = 2\pi f \) is the angular frequency, and \( j = \sqrt{-1} \). Under the applied voltage, an electrical current is generated:

\[ i(t) = i_0 \cdot e^{j\omega t} \]  \hspace{1cm} (A.2)

Which leads the voltage by a phase angle between \(-90^\circ\) to \(0^\circ\).
Applying both the Kirchoff’s circuit law and Ohm’s law, the following equations are formed for a RC circuit with the resistor and the capacitor in series (Fig.A.1.(a)).

\[ v = v_C + v_R, \quad i_C = i_R \]  \hspace{1cm} (A.3)

Therefore,

\[ C \frac{dv_C}{dt} = C \frac{d(v - v_R)}{dt} = \frac{v_R}{R} \]  \hspace{1cm} (A.4)

\[ C \frac{dv}{dt} - C \cdot R \frac{di}{dt} = i \]  \hspace{1cm} (A.5)

where \( C \) is the capacitance and \( R \) is the resistance. Combining Equation (A.1), (A.2) with (A.5) results in:

\[ C \cdot v_o j \omega \cdot e^{j \omega t} - C \cdot R \cdot i_o j \omega \cdot e^{j \omega t} = i_o \cdot e^{j \omega t} \]  \hspace{1cm} (A.6)

Therefore,

\[ i_o = \left( \frac{1}{R + j \omega C} \right) v_o \]  \hspace{1cm} (A.7)

Substituting Equation (A.7) into (A.1), we get:

\[ v(t) = (R - j \frac{1}{j \omega C}) \cdot i_o \cdot e^{j \omega t} \]  \hspace{1cm} (A.8)

According to Ohm’s law, the impedance of the circuit is then:

\[ Z = \frac{v(t)}{i(t)} = R - j \frac{1}{\omega C} \]  \hspace{1cm} (A.9)

Similarly, the impedance for the parallel RC circuit can also be obtained as: 

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Due to the complex pore structure of rocks, the conduction through rocks can be represented as a system of a combination of many resistors and capacitors in parallel and in series. The impedance of this complex circuit lies somewhere in between above two simple cases.

\[ Z = \frac{1}{\frac{1}{R} + j\omega C} \]  

(A.10)
APPENDIX B

ROUTINE ROCK CHARACTERISATION

(a) Porosity Measurements

Porosity is defined as the ratio of pore volume to the bulk volume of a porous media. It can either be total or effective. Total porosity is defined as the ratio of the total pore volume both interconnected and isolated to the bulk volume whereas effective porosity is the ratio of only the interconnected pore volume to the bulk volume. The porosities measured in this study are all effective since they provide the flow path and the storage for the recoverable hydrocarbons.

The helium expansion porosimeter as shown schematically in Fig.B.1 is based on the principle of Boyle’s law which describes an isothermal expansion of ideal gas with equation $PV = \text{constant}$, where $P$ and $V$ are the pressure and volume of the gas respectively. It is believed that this technique has the advantages of accurate, non-destructive and fairly rapid porosity measurements for majority of the rock samples encountered. The reason for using helium gas is that it has one of the smallest atoms and can therefore penetrate all the interconnected pore spaces of any rock sample in the shortest possible time. The absorption of this gas on the surface of rocks is also said to be negligible compared to air.

A simple procedure for the derivation of the grain volume based on Boyle’s law is as follows (Lombos 1983):

$$\frac{P_1 \cdot V_R}{T_1} + \frac{P_2 \cdot V}{T_2} = \frac{P_3 \cdot (V_R + V)}{T_3} \quad (B.1)$$

where

- $P_1 =$ reference pressure
- $V_R =$ reference volume
- $P_2 =$ pressure in the unknown volume
- $V =$ unknown volume
- $T_1, T_2, T_3 =$ absolute temperatures, °K
- $P_3 =$ resultant equilibrium pressure

Since $P_2$ is the atmospheric pressure, under isothermal conditions, i.e. $T_1 =$
Fig. B1 Schematic diagram of the helium gas expansion porosimeter.
$T_2 = T_3$, equation (B.1) becomes:

$$(P_1 + B) \cdot V_R + B \cdot V = (P_3 + B) \cdot (V_R + V)$$  
(B.2)

where $B$ is the barometric pressure. Thus

$$P_3 \cdot V = V_R \cdot (P_1 - P_3)$$  
(B.3)

The above equation can be rewritten as:

$$V = V_R \cdot \left(\frac{P_1}{P_3} - 1\right)$$  
(B.4)

The Term $\left(\frac{P_1}{P_3} - 1\right) = R$ is defined as the expansion ratio. So when all the dummy pieces are in the core holder, equation (B.4) becomes:

$$V_1 = V_R R_1$$  
(B.5)

Similarly, with some dummy cores taken out:

$$V_2 = V_R R_2$$  
(B.6)

and with the core plug in place:

$$V_3 = V_R R_3$$  
(B.7)

where $R_1$, $R_2$ and $R_3$ are all expansion ratios. Therefore,

$$V_2 - V_1 = V_R (R_2 - R_1) = V_D$$

where $V_D$ = dummy core volume. Since $V_D$ is already known, the reference volume ($V_R$) can be calculated from:
\[ V_R = \frac{V_D}{R_2 - R_1} \]

So the grain volume \((V_2 - V_3)\) can be found from:

\[ V_g = V_R(R_2 - R_3) \quad (B.8) \]

The bulk volume of regular rock samples with sharp edges was measured using a caliper. Otherwise a method of volumetric displacement of mercury was applied using an instrument called "pycnometer". There are many disadvantages associated with the use of mercury, though, when this technique is employed (Noman 1988).

(b) Air Permeability Measurements

Permeability is a measure of the specific flow capacity of a porous media and it is independent of the types of pore fluids present. Permeability of any materials can be determined accurately only by flow experiments. Empirical correlations between the porosity and permeability of rocks may exist only for rocks with the same lithology and pore geometry (Archer and Wall 1986).

For flow of fluid, heat and electrical current, a transport equation in the direction of the applied potential gradient is defined as:

\[ \frac{Q}{A} = \frac{U}{-constant} \frac{d\Phi}{dL} \quad (B.9) \]

i.e. a rate of transfer is proportional to a potential gradient. Based on the transport equation, Darcy (1856) derived experimentally a relation which is well known as the Darcy’s law for flow of water through beds of sand as follows:

\[ \frac{Q}{A} = -\frac{k}{\mu} \frac{d\Phi'}{dL} \quad (B.10) \]

and

\[ k = \frac{Q\mu}{A(d\Phi'/dL)} \quad (B.11) \]
where \( k \) = permeability of the rock in Darcy which has a dimension of \( L^2 \), \( \mu = \) viscosity of fluid (\( cp \)), \( \frac{d\Phi'}{dL} = \) datum corrected pressure drop (\( atm/cm \)) and \( A = \) cross section area of flow (\( cm^2 \)). Darcy's law is inadequate at high flow velocities due to the effects of inertial and turbulence. A quadratic equation containing a coefficient of inertial resistance which is dependent on the geometry of the porous medium can be used instead (Noman and Archer 1987).

Laboratory determination of permeability is usually carried out using dry gas (air, \( N_2, H_2 \)) to minimise fluid-rock reaction and for convenience. Fig.B.2 illustrates the schematic arrangement of the Hassler cell assembly for flow measurements. Air from a compressor is injected through the core which is enclosed in a rubber sleeve. A confining pressure of up to 1.7 MPa (250 psi) is applied on the sleeve to prevent any by-pass of air. After the voltage reading shown on the voltmeter stabilises, it is recorded to calculate the pressure drop across the core plug and the flow rate is then measured using a soap-bubble meter. The measurements are repeated at several different flow rates.

Air permeability can be calculated from the following equation:

\[
k_a = \frac{2 \mu L Q_{sc}}{A(P_1^2 - P_2^2)}
\]  

(B.12)

where \( P_1, P_2 \) are the upstream and downstream pressures, and \( Q_{sc} \) is the flow rate measured at standard conditions. The air permeability measured at low pressures is higher than the real permeability and a correction is required. This is known as the Klinkenberg correction for gas slippage during flow of gas through a small capillary as the mean free-path of the molecules approach the dimensions of the flow conduit (Klinkenberg 1941). The equation proposed by Klinkenberg for the correction can be rewritten as:

\[
k_a = k_\infty (1 + b/P_m)
\]  

(B.13)

where \( P_m = \) mean pressure \( [(P_1 + P_2)/2] \) and \( b = a \) constant. A straight line can be obtained by plotting air permeability \( (k_a) \) against the inverse of mean pressure \( (P_m) \). The extrapolation of the straight line to an infinite mean pressure gives the true permeability \( (k_\infty) \) as shown by Fig.B.3 and Fig.B.4 for two different samples measured.
Fig. 6.2 Schematic diagram of the Hassler cell for permeability measurement.
Fig. B.3 A Klinkenberg air permeability correction (sample 16-8A).

Fig. B.4 A Klinkenberg air permeability correction (sample 18'-SE).
The Klinkenberg corrected absolute permeabilities of reservoir rocks measured at laboratory conditions using air as the flow medium are often significantly larger than the true liquid phase permeabilities measured using liquid as the flow medium (Wei et al. 1986). Since reservoirs are under conditions of high pressure and temperature, a knowledge of the effects of pressure and temperature on permeability is important (Gobran et al. 1987). Therefore this thesis also studies the absolute permeability of rocks at elevated pressures and temperatures with liquids as flow media. Details of permeability measurements have been presented in Chapter 7.

(c) Capillary Pressure Measurements

The pore size distribution in a given rock type, which has been shown to influence initial saturation distribution, permeability and electrical resistivity, can be determined using the capillary pressure measurements. There are four basic methods available for experimental determination of capillary pressure characteristics of rock samples. These are:

- (a) Mercury injection method
- (b) Porous diaphragm method
- (c) Centrifuge method
- (d) Dynamic capillary pressure method

Although the mercury injection test is destructive, it is employed in this study because of the advantage that high pressure can be attained and mercury, the non-wetting phase with respect to air, can be forced into very small pores. A schematic arrangement of the apparatus similar to that originally used by Purcell (1949) is shown in Fig. B.5. The core is placed in a chamber under vacuum to remove air from the pore spaces. Mercury is then forced into the core using a hand pump in a stepwise fashion, with sufficient time given for equilibrium at each pressure increase. The non-wetting phase saturation, which is \( S_{Hg} \) in our experiment, can be determined from the volume of mercury injected at each pressure step. The above procedure is repeated until the mercury pressure reaches 8 MPa (1160 psi), which is set by the equipment. The reverse cycle of the withdrawn of mercury is carried out after the maximum pressure has been reached to determine the imbibition capillary pressure and to show the hysteresis.

The pore size distribution function \( (D_r) \) is determined from the capillary pressure curve as follows:
where $P_c$ is the capillary pressure, $r$ is the pore radius and $\frac{dS}{dP_c}$ is the inverse of the slope of capillary pressure plot. Figs. B.6 and B.7 show the capillary pressure and the $D_r$ function for two sandstone samples.

Although there are various methods for carrying out the measurements of porosity, permeability and pore size distributions (capillary pressure) of rocks, for the purpose of the present work only a few are employed and, therefore, are discussed. A general review of these various techniques employed for routine core analysis can be found in the literature (Keelan 1972, Monicard 1980).
Fig. B.5 Schematic diagram of the mercury capillary pressure set-up (after Noman 1988).
Fig. B 6 Capillary pressure and pore size distribution function (sample 18-2C).
Fig B.7 Capillary pressure and pore size distribution function (sample 17-4C).
APPENDIX C

GEOLOGICAL DESCRIPTION OF SANDSTONE ROCKS

Rock sample: S3, S8 and S10 (17-4)
Type: Upper Carboniferous Sandstone from Upper Coal Measures
Grain size: ≤ 0.2 mm
Clay minerals: 5%
Quartz: 85%
Alkali feldspar: 5%
Mica: 2%
Shape: Sub-rounded
Sphericity: Moderate
Maturity: Mineralogically and textually immature

Rock sample: S1, S11 and S12 (16-5)
Type: Upper Carboniferous Sandstone, Millstone Grit Series
Grain size: fine to medium (0.1 - 0.3 mm)
Matrix: Feldspar (50%)
Quartz: 85%
Microcline feldspar: 10%
Mica: 5%
Shape: angular to sub-angular
Sphericity: 0.7; Roundness: 0.3
Maturity: Mineralogically Submature, textually immature

Rock sample: S2, S13 and S14 (15-8)
Type: Lower Carboniferous Sandstone from Fell Sandstone Group
Grain size: 0.2 mm
Quartz: 95%
Feldspar, Clay inclusions, biotite: 5%
Cement: Calcite (35%), with some chert
Shape: Angular to sub-angular
Sphericity: Poor
Maturity: Mineralogically mature, textually submature to mature

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Rock sample: S4, S7 and S15 (19'-2)
Type: Lower Triassic Bunter Sandstone
Grain size: fine to medium (≤ 0.5mm)
Clay minerals: 0
Quartz: 95%
Alkali feldspar, Calcite: 5%
Shape: Sub-angular - sub-rounded
Sphericity: Poor
Maturity: Mineralogically mature, textually sub-mature

Rock sample: S5, S6 and S9 (18-2)
Type: Lower Permian “Penrith Red Sandstone”
Quartz: predominantly quartz grains cemented by quartz over-growths with iron oxide petina
Clay minerals: 0
Shape: Sub-rounded - rounded
Sphericity: Poor
Maturity: Mineralogically and textually sub-mature
APPENDIX D

EXPERIMENTAL DATA IN TABULAR FORM

Here:

Nor. F = Normalised F  
m' = Cementation factor before porosity correction  
m = Real cementation factor after porosity correction  
Poro. = Porosity (fraction)

1. Formation factor (F) and cementation factor (m) at various pressures (Room Temperature)

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- Core S2 -

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258
3.

The combined effect of pressure and temperature on
resistivity factor (F)

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### Core A11 and A12

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6. Rock conductivity (Co) vs. solution conductivity (Cw) (Room Temperature), both conductivities are in mho/m.

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7. Rock conductivity (Co) vs. solution conductivity (Cw) at various temperatures, both conductivities are in mho/m.

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127.5 °C

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<td>3.27</td>
</tr>
<tr>
<td>27.57</td>
<td>2.06</td>
<td>2.02</td>
<td>2.61</td>
<td>2.20</td>
<td>1.73</td>
</tr>
<tr>
<td>11.80</td>
<td>1.07</td>
<td>1.09</td>
<td>1.31</td>
<td>1.43</td>
<td>0.86</td>
</tr>
</tbody>
</table>

153.1 °C

<table>
<thead>
<tr>
<th>Cw</th>
<th>Co(A1)</th>
<th>Co(A2)</th>
<th>Co(A3)</th>
<th>Co(A4)</th>
<th>Co(A5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>71.48</td>
<td>4.69</td>
<td>4.07</td>
<td>5.59</td>
<td>4.61</td>
<td>3.71</td>
</tr>
<tr>
<td>33.97</td>
<td>2.38</td>
<td>2.34</td>
<td>3.06</td>
<td>2.57</td>
<td>1.98</td>
</tr>
<tr>
<td>13.51</td>
<td>1.18</td>
<td>1.28</td>
<td>1.57</td>
<td>1.68</td>
<td>0.99</td>
</tr>
</tbody>
</table>

8. Normalised permeability vs. confining pressure at room temperature

<table>
<thead>
<tr>
<th>P (MPa)</th>
<th>K(S1)</th>
<th>K(S2)</th>
<th>K(S3)</th>
<th>K(S4)</th>
<th>K(S5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.0</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
<td>1.000</td>
</tr>
<tr>
<td>6.0</td>
<td>0.871</td>
<td>0.956</td>
<td>0.932</td>
<td>0.975</td>
<td>0.905</td>
</tr>
<tr>
<td>8.0</td>
<td>0.852</td>
<td>0.941</td>
<td>0.899</td>
<td>0.963</td>
<td>0.863</td>
</tr>
<tr>
<td>12.0</td>
<td>0.799</td>
<td>0.933</td>
<td>0.863</td>
<td>0.948</td>
<td>0.842</td>
</tr>
<tr>
<td>16.0</td>
<td>0.760</td>
<td>0.910</td>
<td>0.837</td>
<td>0.930</td>
<td>0.819</td>
</tr>
<tr>
<td>20.0</td>
<td>0.724</td>
<td>0.891</td>
<td>0.822</td>
<td>0.920</td>
<td>0.782</td>
</tr>
<tr>
<td>24.0</td>
<td>0.668</td>
<td>0.878</td>
<td>0.796</td>
<td>0.913</td>
<td>0.757</td>
</tr>
<tr>
<td>29.5</td>
<td>0.641</td>
<td>0.865</td>
<td>0.783</td>
<td>0.906</td>
<td>0.735</td>
</tr>
</tbody>
</table>

9. Normalised permeability vs. temperature (P = 13.8 MPa)

<table>
<thead>
<tr>
<th>T (°C)</th>
<th>K(S1)</th>
<th>K(S3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>23.1</td>
<td>1.000</td>
<td>1.000</td>
</tr>
<tr>
<td>45.2</td>
<td>0.921</td>
<td>0.943</td>
</tr>
<tr>
<td>53.1</td>
<td>0.885</td>
<td>0.920</td>
</tr>
<tr>
<td>63.6</td>
<td>0.867</td>
<td>0.887</td>
</tr>
<tr>
<td>82.0</td>
<td>0.808</td>
<td>0.845</td>
</tr>
<tr>
<td>93.0</td>
<td>0.761</td>
<td>0.812</td>
</tr>
</tbody>
</table>

10. Normalised permeability vs. brine concentration for shaley samples

<table>
<thead>
<tr>
<th>C (grams/l)</th>
<th>A1</th>
<th>A2</th>
<th>A3</th>
<th>A8</th>
<th>A9</th>
</tr>
</thead>
<tbody>
<tr>
<td>120</td>
<td>467.26mD</td>
<td>278.61mD</td>
<td>73.63mD</td>
<td>347.43mD</td>
<td>301.38mD</td>
</tr>
<tr>
<td>50</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>20</td>
<td>0.99</td>
<td>0.96</td>
<td>0.86</td>
<td>0.99</td>
<td>0.98</td>
</tr>
<tr>
<td>5</td>
<td>1.00</td>
<td>0.72</td>
<td>0.43</td>
<td>0.90</td>
<td>0.80</td>
</tr>
<tr>
<td>2</td>
<td>0.99</td>
<td>0.67</td>
<td>0.25</td>
<td>0.89</td>
<td>0.87</td>
</tr>
</tbody>
</table>
APPENDIX E

DESCRIPTION OF NETWORK MODELS

Description of NETSIM

NETSIM is written to simulate the pressure and temperature dependent rock transport properties. This 3D model consists of pore tubes connected to pore nodes. Three pore tube shapes, i.e., elliptic, tapered and grain boundary pore (GBP), are used in the model. The lattice is regular with coordination number of \( \leq 6 \). Fig.E.1 shows the flow chart of the program NETSIM. A brief description of each subroutine is given below:

NETSIM:

This is the main program which defines the boundary conditions and initial approximations of potential (both hydraulic and electrical) distribution in the model, conducts the main iteration process and computes the transport properties for a defined model. A technique of successive over-relaxation is used to calculate the potential distribution.

SUB1:

This subroutine calculates the electrical and hydraulic resistances for all the pore elements.

SUB2:

This subroutine calculates the elastic deformations for all the pore elements based on the Hertz contact theory.

SUB3 and SUB33:

These two subroutines are mesh generators which generate the pore size, pore aspect ratio distributions for the model according to the distribution type required.

SUB4:

This subroutine calculates the pore size changes induced by the thermal expansion of rock forming materials.
Fig 5.1 Flow chart of the simulator (NETSIM).
Description of CLAY

CLAY is written to investigate the effect of clay minerals on shaley sand electrical conductivity and to provide a means for the quantification of the clay distribution coefficient ($\tau$) defined in this thesis. The basic elements of CLAY are the same as in NETSIM. The flow chart is shown in Fig.E.2. The subroutines are described briefly as follows:

CLAY:

This is the main program which defines the boundary conditions and initial approximations of voltage distribution for all the nodes in the model. CLAY also conducts the main iteration process and computes the $C_o$ vs. $C_w$ for a defined model. A technique of successive over-relaxation is also used in this main routine.

INDAT:

This subroutine reads input data for the main simulation.

CSUB1:

This subroutine generates pore size, clay content ($Q_u$), and calculates the equivalent electrical resistance (i.e., both the brine conductivity and the electrical double layer excess conductivity are considered) for all the pore tubes based on a given shaley sand conductivity model such as the W-S or the D-W.

CSUB2:

This subroutine is a mesh generator which generates the pore size for the model according to a given pore size distribution function.

CSUB3 and CSUB4:

These two subroutines distribute clay minerals in the network model for dispersed and laminated clay distributions respectively. For a given clay distribution mode, the $DOD$ or $DOL$ may vary.
Fig. 6.2 Flow chart of the simulator (CLAY).
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