

**THE EFFECT OF CLAY MINERALS ON RESERVOIR
CHARACTERIZATION AND PERFORMANCE**

By

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CERTIFICATION OF APPROVAL

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABSTRACT

Clay minerals are fine-grained which compose of aluminium silicate structure. There are four main groups of clay minerals which are kaolinite, illite, smectite and chlorite. The effect of clay minerals on formation evaluation and reservoir performance depend on its morphology, cation exchange capacity and swelling properties. The occurrence of clay minerals leads to inaccurate values of porosity, water saturation and permeability. In addition, the impacts of clay minerals during drilling, water injection and acid stimulation are investigated as it can lead formation damage near wellbore. The current project aims investigate the effect of clay minerals on logs response and reservoir characteristics in term of porosity, permeability and water saturation, and to compare its impact on reservoir performance against reported works. Methodology used in the present research involves log interpretation (gamma ray, neutron, density and resistivity) and clay mineral characterization (using thin section, polarized microscope, SEM and FESEM/EDX) to analyse the effect of clay on water relative permeability, water saturation and capillary pressure curve. Results were discussed and benchmarked against selected literatures. Based on the effect of clay minerals, there are reduction in water relative permeability due to fine migration and swelling of clays. In addition, it is found that accurate value of water saturation can be obtained by using Waxman-Smit-Thomas model. Moreover, it is shown that capillary pressure curve is reflected by the heterogeneity and bimodality of the reservoir. In this project, it is shown that effect of clay minerals on reservoir can lead to the inaccuracy of determining reservoir characterization and its effect on reservoir productivity.

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ABBREVIATION & NOMENCLATURE

LIST OF ABBREVIATION

CEC	–	Cation Exchange Capacity
FESEM/EDX	–	Field-Emission Scanning Electron Microscope/ Energy Dispersive X-Ray
GR	–	Gamma Ray
HCl	–	Hydrochloric
HF	–	Hydrofluoric
KCl	–	Potassium chloride
K-Feldspar	–	Potassium Feldspar
NGS	–	natural gamma ray spectrometry
NMR	–	Nuclear Magnetic Resonance
PCSB	–	Petronas Carigali Sdn Bhd
SEM	–	Scanning Electron Microscope
SGR	–	Spectral Gamma Ray
SP	–	Spontaneous Potential

LIST OF NOMENCLATURES

a	–	Constant Value
Al	–	Aluminium
Al^{3+}	–	Aluminium Ion
$\text{Al}(\text{OH})_6^{-3}$	–	Alumina-Octahedral
B	–	Specific Conductivity Of Exchangeable Cations
C	–	Carbon
Ca	–	Calcium
Ca^{2+}	–	Calcium Ion
C_0	–	Conductivity Of Water Saturated Sandstone
C_t	–	Formation Conductivity

C_w	–	Water Conductivity
F	–	Formation Factor
Fe	–	Iron
GRlog	–	Gamma Ray Log Reading In Zone Of Interest
GRmax	–	Minimum Value Of The Gamma Ray Log
GRmin	–	Minimum Value Of The Gamma Ray Log
K	–	Potassium
Mg	–	Magnesium
m	–	Cementation Factor
n	–	Saturation Exponent
O	–	Oxygen
OH	–	Hydroxyl
Pe	–	Petroelectric Factor
PV	–	Pore Volume
q	–	Fraction Of Inter Matrix Porosity Occupied By Dispersed Shale
Q_v	–	Clay Cation Exchange Capacity
RESD	–	Resistivity Log Reading From Zone Of Interest
RESD_CLN	–	Resistivity Log Reading From Clean Sand
RESD_SHL	–	Resistivity Log Reading From Shale
R_o	–	Resistivity Of Reservoir Rock
R_{sd}	–	Resistivity Of Shale Laminae
R_{shd}	–	Resistivity Of Dispersed Shale
R_{sh}	–	Resistivity Of Clean Sand Laminae
R_t	–	Observed Bulk Resistivity
R_w	–	Aqueous Electrolyte Resistivity
S	–	Sulphur
S_{cbw}	–	Saturation Of Clay Bound Water
Si	–	Silica
$Si_2O_5^{-2}$	–	Silica-Tetrahedron
S_{im}	–	Fraction Of Inter Matrix Porosity
S_w	–	Water Saturation

$S_{w, effective}$	–	Effective Water Saturation
S_{wf}	–	Formation Water Saturation
S_{wi}	–	Initial Water Saturation
S_{wt}	–	Total Water Saturation
Th	–	Thorium
Ti	–	Titanium
V_D	–	Dispersed Volume Of Shale
V_L	–	Laminated Volume Of Shale
$Vol_{clay-bound-water}$	–	Volume Of Clay Bound Water
$Vol_{dry-clay}$	–	Volume Percentage Of Clay Abundance
V_{sh}	–	Volume Of Shale
V_S	–	Structural Volume Of Shale
V_Q	–	Clay Cation Exchange Capacity
$W_{dry-clay}$	–	Weight Percentage Of Formation Rock Matrix
X	–	Excess Conductivity
ρ_b	–	Bulk Density Read From The Log
$\rho_{dry-clay}$	–	Dry Clay Density
ρ_f	–	Fluid Density
ρ_{ma}	–	Density Of Rock Matrix
ϕ_D	–	Density Porosity In The Sand
$\phi_{effective}$	–	Effective Porosity
ϕ_N	–	Neutron Porosity In The Sand
ϕ_{DSH}	–	Density Porosity In Adjacent Shale
ϕ_{im}	–	Inter Matric Porosity
ϕ_{max}	–	Maximum Porosity
ϕ_{NSH}	–	Neutron Porosity In Adjacent Shale
ϕ_T	–	Total Porosity
ϕ_{TSH}	–	Total Porosity Of Shale

CHAPTER 1

INTRODUCTION

1.1 Background Study

Clay minerals are essential components in petroleum system as sources of sealing rocks. The effects of clay minerals in reservoir characterization can be examined by the evaluation and measurement of porosity, formation water saturation and permeability of reservoir from logging tools. The presence of clay-bound-water affects porosity and electrical properties of the formation by overestimating the porosity value due to significant amount of hydrogen and underestimating the resistivity value due to presence of excess of conductivity in the formation. Inaccuracy in reservoir properties leads to wrong interpretation of reservoir volume and hydrocarbon-in-place.

In addition, the presence of clay minerals in shaly reservoir during drilling, water injection and acid stimulation can affect reservoir performance in terms of permeability impairment near wellbore area due to fines migration and swelling properties of clay minerals. Hence, the effect of clay minerals towards reservoir characterization and performance need to be investigated in order to obtain accurate data on reservoir properties and to avoid declining of reservoir productivity.

1.2 Problem Statement

The presence of clay minerals in shaly reservoir should be taken into account as it can affect reservoir characterization and performance. In formation evaluation and log interpretation, the existence of clay minerals in the reservoir might lead to inaccurate values of porosity, water saturation and permeability. Since these parameters are important in determining the volume of reservoir and hydrocarbon-in-place, the accurate values of these properties need to be obtained. In addition, clay minerals can also lead to

formation damage due to its cation exchange capacity and swelling properties. Hence, this will affect permeability of reservoir hence its performance.

According to Kurniawan (2005), there are several effects of clay minerals in shaly reservoir in terms of reduction in effective porosity and permeability which are:

- Further reduction in permeability due to migration of loose and fines clay minerals that plug the pore throat.
- Water sensitivity; in terms of hydration and swelling of clay minerals when in contact with water (mud filtrate).
- Acid sensitivity; when acid reacts with iron-bearing clays form a gelatinous precipitation that clogs pore throat and reduce permeability.
- Influence logging tools responses.

Therefore, it is important to identify the effect of clay minerals on log response as logging tools are used to determine porosity, water saturation and permeability of reservoir.

1.3 Objectives

The main objectives of this project are:

1. To examine effects of clay minerals on logs response.
2. To investigate effects of clay minerals on reservoir rock characteristics.
3. To compare the impact of clay minerals on reservoir performance against reported works.

1.4 Scopes of Study

The scopes of study in this project are to examine types and characteristics of clay minerals in order to have better understanding on its properties. Next, the effects of clay minerals on logs response, reservoir characterization and performance are investigated. The effect of clay minerals on logs response will be based on the impact of clay minerals especially in gamma ray, resistivity, neutron and density logs. Then, the effect

of clay minerals on reservoir performance will be analysed from all aspects; drilling, water injection and acid stimulation. In addition, the impact of clay minerals on permeability of reservoir due to formation damage will be discussed.

In this project, some of clay minerals samples are analysed in order to investigate the occurrences and identification of clay minerals. Various integrated methods have been used for this purpose such as thin section, SEM and FESEM/EDX. In addition, the effects of clay minerals on water relative permeability, saturation and capillary pressure curve are discussed into details. Moreover, the critical reviews on logs response and formation damage will also be conducted.

CHAPTER 2

LITERATURE REVIEW

2.1 Clay Minerals

Clay minerals are complex alumina-silicates with definite crystalline structure. It has very fine-grained with particle diameter size less than 0.00625 mm (Kurniawan, 2005). Hence, it has high surface area property. In addition, clay minerals have a potential to shrink or swell in wet and dry conditions; depending on its properties. Guggenheim and Martin (1995), define that clays are organic material that have an ability to be moulded to any shape. In addition, it is also known as phyllosilicates as it produces the plasticity property. Figure 2.1 shows molecular, structural and building block of clay minerals.

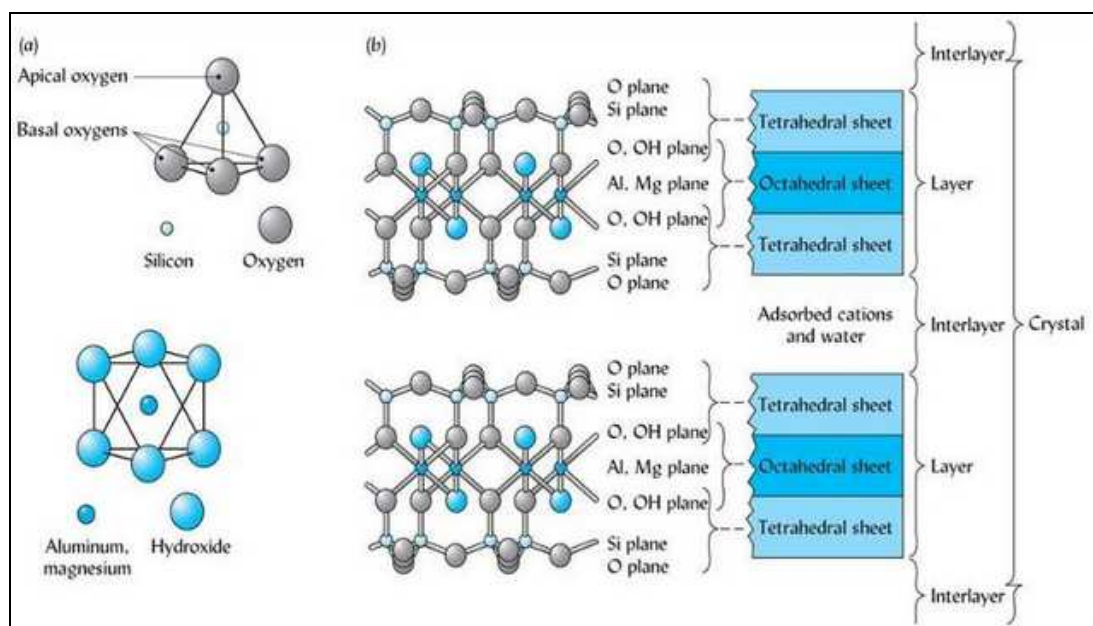


Figure 2.1: Basic Molecular and Structural Components of Clay Minerals (a) Silica-Tetrahedron and Alumina/Magnesium-Octahedron, (b) Clay Crystal Building Blocks (Trainor, 2013)

Clay minerals are structured in sheets of alumina-octahedral ($\text{Al}(\text{OH})_6^{-3}$) and silica-tetrahedron ($\text{Si}_2\text{O}_5^{-2}$) lattices. In tetrahedral unit, a silicon atom is located in the centre of tetrahedron equidistant from four oxygen atoms or hydroxyls. Meanwhile for octahedral units, two sheets of closely packed oxygen or hydroxyl atoms into aluminium, iron or magnesium atoms are embedded into its structure.

2.1.1 Types and Distribution of Clay Minerals

Clay minerals are produced by degradation processes such as weathering and hydrothermal of other silicates, or by direct precipitation from a solution (Petroleum Geoscience Manual, 2011). Clay minerals can be divided into four major important groups which are Kaolinite, Illite, Montmorillonite (Smectite) and Chlorite. The origin and characteristics of these types of clay minerals are shown in Table 2.1, meanwhile its chemical composition and morphology is shown in Table 2.2.

Table 2.1: The Origin and Characteristics of Clay Minerals (Petroleum Geoscience Manual, 2011)

Types of Clay Minerals	Origin	Characteristics
Kaolinite - Dickite - Nacrite	Produced by destruction of alkali feldspars under acidic conditions	– main constituent of china clay – important pore-blocking mineral in sandstone
Illite (Mica) (Vermiculite); - Hydroumicas, (Glauconite)	Alteration of micas, alkali and feldspars, under alkaline conditions	– important pore-blocking clay
Montmorillonite - Smectite/ Fullers' Earth - Bentonite - Nintronite - Beidellite	Alteration of mafic igneous rocks and other silicates (low in K) under alkaline conditions (Ca/Mg present)	– important base exchange properties (takes up and loses water); swelling clays
Chlorite	Alteration products of ferromagnesian minerals in metamorphic/igneous rock	– important component in mudstones – pore blocking in sandstone

Table 2.2: Chemical Composition and Morphology of Clay Minerals (Ezzat, 1990)

Mineral	Chemical Composition	Morphology
Kaolinite	$\text{Al}_4[\text{Si}_4\text{O}_{10}](\text{OH})_8$	Stacked plate or sheets.
Chlorite	$(\text{Mg}, \text{Al}, \text{Fe})_{12}[(\text{Si}, \text{Al})_8\text{O}_{20}](\text{OH})_{16}$	Plates, honeycomb, cabbagehead rosette or fan.
Illite	$(\text{K}_{1-1.5}, \text{Al}_4[\text{Si}_{7-6.5}\text{Al}_{1-1.5})_{20}](\text{OH})_4$	Irregular with elongated spines or granules.
Smectite (Montmorillonite)	$(1/2\text{Ca}, \text{Na})_{0.7}(\text{Al}, \text{Mg}, \text{Fe})_4[(\text{Si}, \text{Al})_8\text{O}_{20}].n\text{H}_2\text{O}$	Irregular, wavy, wrinkled sheets, webby or honeycomb.
Mixed Layer	<ul style="list-style-type: none"> • Illite-Smectite • Chlorite-Smectite 	Ribbons substantiated by filamentous morphology.

In addition, clay minerals can also be classified into allogenic (detrital) and authigenic clays based on its occurrences during deposition (Ali et al., 2010). For allogenic clays, it is formed prior to a deposition and become mixed with sand-sized mineral grains during or immediate following deposition. Meanwhile, authigenic clays develop within the sand subsequent to burial. The characteristics and geological classification of allogenic and authigenic clays are shown in Table 2.3.

The occurrence and distribution of allogenic and authigenic clays in sandstone reservoirs is shown in Figure 2.2. Pittman and Thomas (1979) indicate that clays with associated micropores may occur as detrital laminae, pellets (grains) of silt-sized or coarser material, or as authigenic (newly formed or regenerated) material.

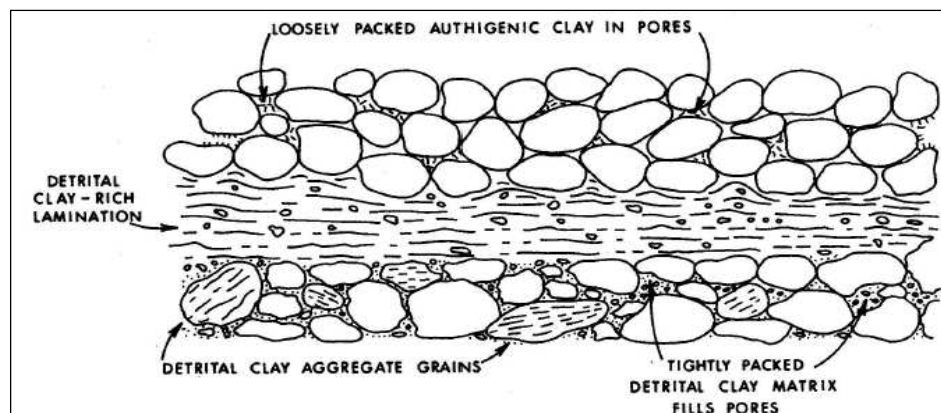


Figure 2.2: Occurrence of Clay Minerals in Sandstones (Pittman and Thomas, 1979)

**Table 2.3: Classification and Distribution of Clay Minerals
(Modified Serra, 2007)**

Classification of Clays	Characteristics and Geological Classification		Clay Distribution
Allogenic	Granular Shales	Grains of mudstone or floccules	Structural shales
		Biogenic pellets (sometimes glauconotized)	
	Detrital Clay Minerals	Quartz grains randomly distributed	
		Laminated layer	Laminated shales
	Shale Matrix	Detrital clay minerals filling the pore space	Dispersed shales
Authigenic	Clay mineral from alteration in situ of feldspars and micas	- discrete particles - pore lining - pore bridging	Dispersed clays
	Pseudomorphoses replacement (i.e feldspars)		
	Formation of clay mineral under hydrothermal influences	Pore filling	
		Fracture filling	Laminate clays
	Concentration of insoluble constituents (clay organic matters) under pressure and solution	Stylolites	

Furthermore, clay minerals can be distinguished into three modes of distribution which are laminar, structural and dispersed. The schematic diagram of clays distribution is shown in Figure 2.3. These types of clays distribution can appear instantaneously in the same formation. It is significant to identify the way of clays distribution in the formation as it will effect characterisation and performance of the reservoir.

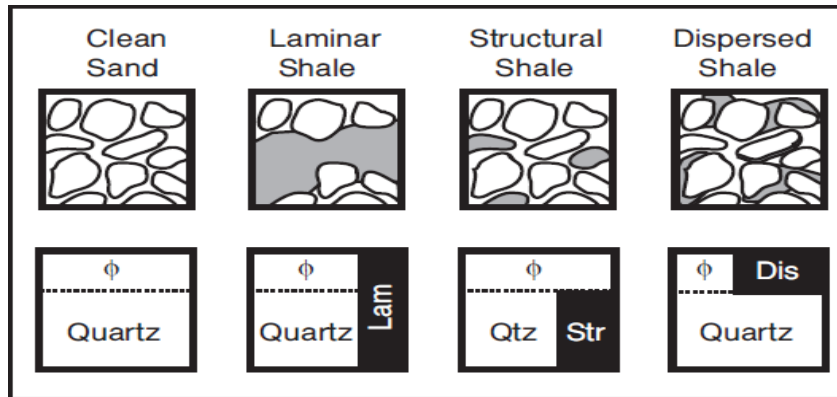


Figure 2.3: Schematic Diagram of Clays Distribution
(Formation Evaluation Manual, 2012)

Table 2.4 shows characteristics and effect of clay distributions on reservoir characterization. From the table, laminar and structural clay distributions are only affecting overall average effective porosity of the formation. Meanwhile, dispersed clay distribution is more severe as it can reduce permeability of the formation.

Table 2.4: Characteristic of Types of Clay Distribution
(Formation Evaluation Manual, 2012)

Clay Distribution	Physical Properties	Characteristics
Laminar	<ul style="list-style-type: none"> Thin beds or streaks of shale deposited between layers of reservoir rock. 	<ul style="list-style-type: none"> Do not alter effective porosity and permeability of sand streaks. Amount of porous medium decrease as its amount increase.
Structural	<ul style="list-style-type: none"> Exist as grains or nodules in formation matrix with quartz or other grains. 	<ul style="list-style-type: none"> Similar properties to laminar shale and nearby massive shales.
Dispersed	<ul style="list-style-type: none"> Dispersed throughout the sand and partially filling intergranular interstices. Adhere to or coating the sand grains, or partially fill the smaller pore channels. 	<ul style="list-style-type: none"> Reduces permeability of the formation.

In addition, Thomas and Stieber (1975) introduce a cross-plot of density and gamma ray log in order to determine shale configuration, sand fraction and sand porosity. This approach is an approximate solution that can be used on heterogeneous shaly sand into its constituent fractions of different types of clay distribution.

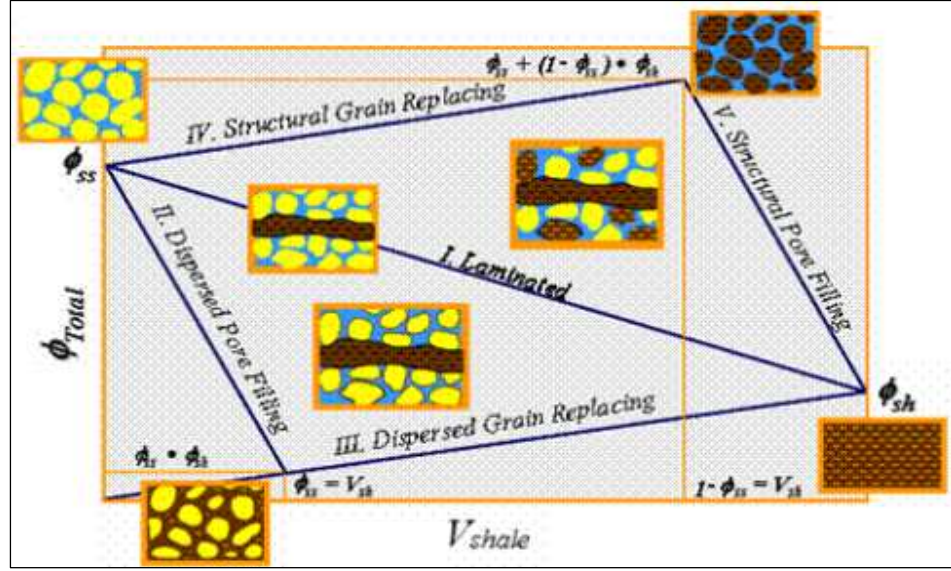


Figure 2.4: Thomas Stieber Shale Distribution Model
(Tyaga et al., 2009)

Tyaga et al. (2009) has developed modified version of Thomas Stieber shale distribution model as shown in Figure 2.4. From this cross-plot, shale distribution and total porosity can be computed based on equations below:

- Laminated shale only ($V_{sh} = V_L$)

$$\phi_T = \phi_{\max} - V_L(\phi_{\max} - \phi_{Tsh}) \quad (2.1)$$

- Dispersed shale only ($V_{sh} = V_D$)

$$\phi_T = \phi_{\max} - V_D(1 - \phi_{Tsh}) \quad (2.2)$$

- Structural shale only ($V_{sh} = V_S$)

$$\phi_T = \phi_{\max} + V_S \phi_{Tsh} \quad (2.3)$$

- Material balance for shale

$$V_{sh} = V_L + V_D + V_S \quad (2.4)$$

According to Naesham (1977), dispersed clays can be distinguished into two criteria which are crystal structure and location on pore walls (mineral surfaces) and/or within intergranular pore and pore throats. In addition, it can also exist as discrete, lining and bridging as shown in Figure 2.5 and its characteristics and effect on pore system are discussed as in Table 2.5.

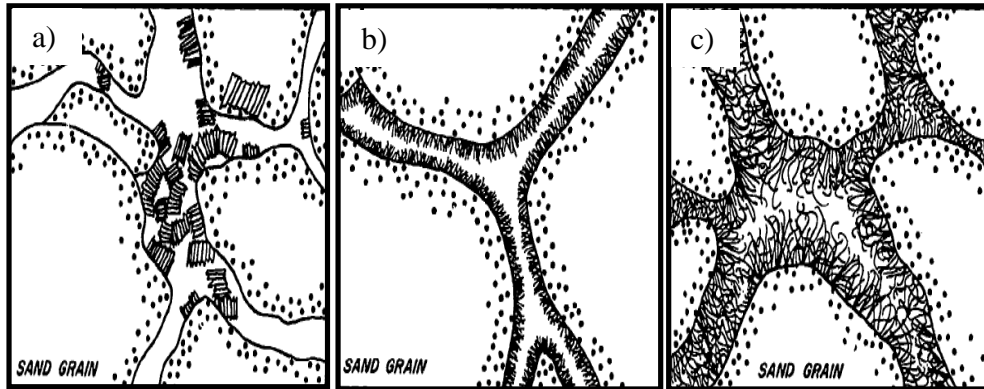


Figure 2.5: Schematic Diagram for Dispersed Clay Distribution a) discrete, b) lining c) bridging (Modified Neasham, 1977)

**Table 2.5: General Types of Dispersed Clay in Sandstone Reservoir
(Naesham, 1977)**

Types of Dispersed Clay	Characteristics	Effect on Pore System
Discrete	- Develop as pseudohexagonal, platy crystals attached as discrete particle to pore walls or occupying intergranular pores.	- Reducing intergranular pore volume. - Behave as migrating “fines” in pore system.
Linings	- Attach to pore walls to form continuous and thin coating. - Clay crystal oriented parallel or perpendicular to the pore wall surface.	- Perpendicular – intergrown to form continuous clay layer containing abundant micropore space.
Bridging	- Attach to pore wall surfaces extend into or completely across a pore/pore throat to create a bridging effect.	- Extensive development of intergrown and/or intertwined clay crystal within pore system.

Furthermore, Ali et al. (2010) identifies that authigenic clays in sandstone can be found in four forms:

- Clay coatings – deposited on surfaces of framework grains. It acts as pore-lining clays in the interstices between grains in which it will grow outward from the grain surfaces and often merge with linings on opposing grains also known as pore bridging.
- Individual clay pore-filling flakes or aggregates flakes – it can plug interstitial pores and exhibit no apparent alignment relative to framework grain surfaces.
- Partially or completely replace detrital grains or fill voids left by dissolution of framework grains.
- Fill vugular pores and fractures.

In reference to work of Naesham (1977) on porosity and permeability relationship on dispersed clay morphology, discrete particle give highest porosity and permeability of the sands since discrete particle is only effect on intergranular pore system. Meanwhile, pore-lining has intermediate permeability as its pore walls extensively coated with clay

crystals. The lowest permeability sand is on pore-bridging due to its fibrous, intergrown crystals extending far into intergranular pores. This relationship is shown in Figure 2.6.

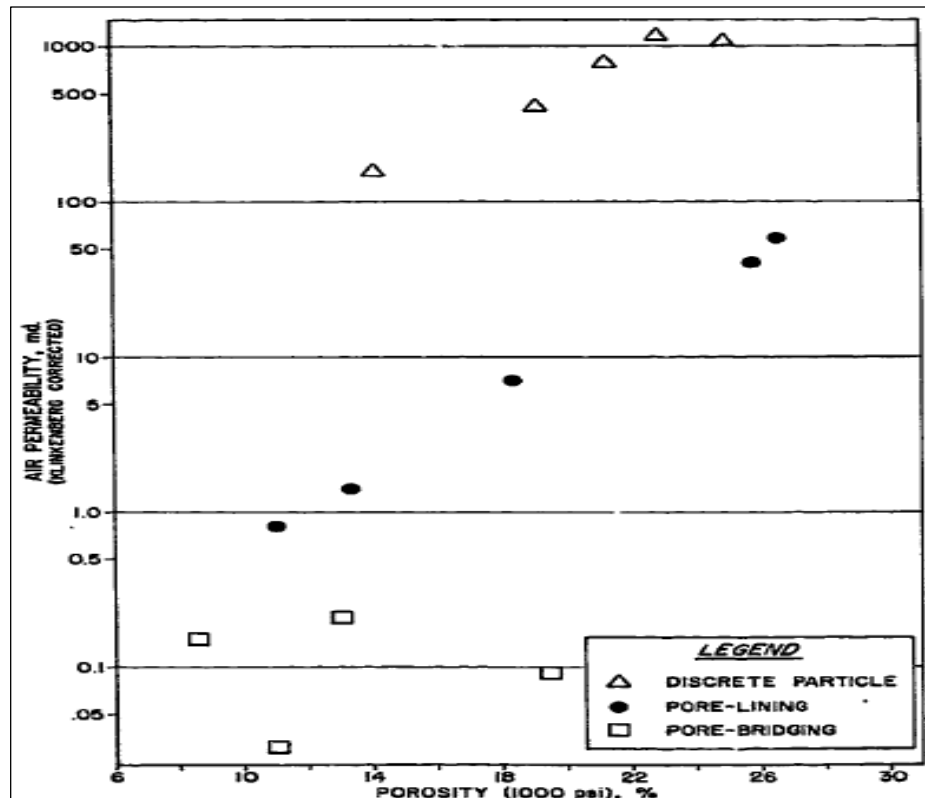


Figure 2.6: Porosity and Permeability Relationship for Dispersed Clay Morphology (Naesham, 1977)

Recent study done by Ajdukiewicz and Larese (2012) indicate that diagenetic clay coats affect reservoir quality by inhibition of quartz cement. The clay coats contain significant interparticle microporosity with high surface area, high irreducible-water saturation and lower permeability. These irreducible-water saturation can contribute to the overall conductivity of the formation, hence will influence electrical properties measured by logging tools.

2.1.2 Cation Exchange Capacity (CEC)

Clean sand consists of pure silica and oxygen atoms which are known as quartz. However, with presence of clay minerals in the formation, there will be a substitution of silica (Si^{4+}) by aluminium (Al^{3+}) in mineral structure of clay; hence leave clay surface with negatively charge. Ketterings et al (2007) indicates that negatively charge of clay minerals tends to balance the charge with positively charge cations in soil such as calcium (Ca^{2+}), magnesium (Mg^{2+}), and potassium (K^{+}). The ability of clay minerals to exchange with other cations is called Cation Exchange Capacity (CEC). The physical properties of clay minerals are shown in Table 2.6. CEC can be related to the surface area of clays depending on its types, for example, Kaolinite has the lowest and Montmorillonite has highest value of CEC and surface area.

Table 2.6: Typical Properties of Clays (Ezzat, 1990; Darling, 2005)

Types of Clay	CEC (meq/100g)	Surface Area (m²/gm)	Grain Density (g/cc)	Hydrogen Index
Kaolinite	3-15	20	2.64	0.37
Illite	10-40	100	2.77	0.09
Montmorillonite	80-150	700	2.62	0.12
Chloride	1-30	100	3.00	0.32

Based on Drilling Engineering Manual (2005), charges on clay surfaces are based on two mechanisms which are isomorphous substitution and broken edge charges. In isomorphous substitution, the charge of clay minerals have been neutralised by adsorption of cation. The feasibility of cation exchange is depends on concentration of cations, population of exchange sites and nature of ions and clay itself. Meanwhile, broken edge charges is happen due to the broken of clay sheet which leads to the unbalanced charges on clay surfaces. High value of CEC means formation has higher amount of clay minerals, and it also indicates that clays can have more water holding capacity. In addition, CEC of clay minerals can also be related with swelling properties especially when it is in contact with fresh water and incompatible fluid.

Swelling Properties

Swelling of clays happen when the exchangeable cations are hydrated and water molecules enter the space between clay structural layers and leads to the increases of distance between layers and the volume of clay expands (Zhou and Davis, 1998). Hence, swelling properties of clay minerals are depending on type of exchangeable cations, formation fluid and clay compositions. Generally, some clay minerals swell when wet and are plastic, while others are hard and dense (Woodhouse and Warner, 2004). As mentioned earlier, smectite group of clay minerals have an ability to swell with presence of water; hence it can give significant effects on porosity and permeability of the formation.

According to Stewart and Mahmoud (2012), clay-water sensitivity can be take place by two mechanisms, which are through interlayer and interparticle interactions. In interlayer interactions, swelling of lattice volume happens due to hydration. This mechanism will cause static permeability reduction with no actual movement on clay. Moreover, for interparticle interactions, clay-water sensitivity is based on the behaviour of negatively clay surfaces charge which is due to cations substitution.

Clay Bound Water

Clay bound water is associated with water held to net-negatively charged on clays surface and water of hydration related with mineral charge balancing cations (Pallatt and Thornley, 1990). Figure 2.7 shows schematic model of clay bound water on clay surface. Since there is water that has already absorbed by clay minerals surface, hence, the existence of sodium counterions (Na^+); to balancing negative charge of clay minerals are located further away from clay surface. In addition, there will be a shell of hydration water molecules surrounding sodium ion (Clavier *et al.*, 1984).

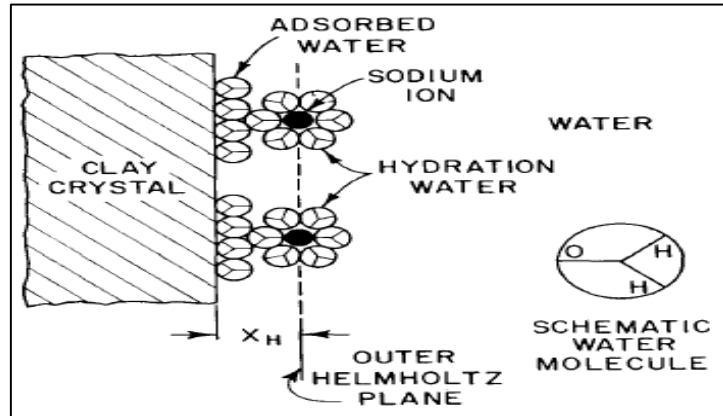


Figure 2.7: Model of Water Bound to a Clay Surface (Clavier et al., 1984)

Clay bound water is least mobile compare to free and capillary water. Thus, it is important to understand types of water in the pore spaces, its quality and distribution in evaluating porosity of reservoir. The types of water in pore space and its characteristics are shown in Table 2.7.

Table 2.7: Types of Water in Pore Space (Pallatt and Thornley, 1990)

Types of Water	Characteristics
Free Water	- Able to flow under applied pressure gradient.
Capillary Water	- Immobile water held by capillary forces in regions of microporosity, for example dead-end pores and pendular rings.
Bound Water	- Consists of both water strongly held to negatively charged clay mineral surfaces and water of hydration associated with mineral charge-balancing cations.

2.2 Shaly Sand Interpretation Model

Shaly sand interpretation can be divided into shale and clay model (Shahzad, 2005). Each model used different approaches in interpreting lithology, porosity, resistivity and water saturation in shaly sand. Some approaches will be discussed in this section, while others will be discussed in the effect of clay minerals on logs response section.

2.2.1 Shale Model

In shale model, rock matrix is described as shale and quartz, in which shale consists of clay, mica, feldspar, iron oxide and organics. The volume of shale will be calculated based on gamma ray reading. Adeoti (2009) has suggested two methods in calculating volume of shale from Natural Gamma Ray:

- **Linear Method**

$$V_{sh} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (2.5)$$

Where,

V_{sh} = volume of shale

GRlog = gamma ray log reading in zone of interest

GRmin = minimum value of the gamma ray log

GRmax = maximum value of the gamma ray log

- **Steiber Methods (Non-Linear)**

$$V_{sh}(Steiber) = \frac{0.5 \times V_{sh}(linear)}{1.5 \times V_{sh}(linear)} \quad (2.6)$$

The non-linear method is used in unconsolidated rocks because they are more chemically immature and may contain radioactive minerals such as feldspars that could contribute to gamma ray; however these minerals are unrelated to shale volume (Adeyemo *et al.*, 2005).

Moreover, amount of shale can be determined by spontaneous potential (SP) and porosity logs. Kurniawan (2005) indicates that shale model is developing based on distribution of clays in the formation; whether it is laminated or distributed in the pore space.

2.2.2 Clay Model

The lithology of clay model can be described as clay (kaolinite, illite, montmorillonite and chlorite,) and sand (quartz, mica, and feldspar). According to Shahzad (2005), clay abundance obtained from experimental measurement on representative formation rock can be used to calibrate clay abundance estimated from clay indicator logging data. By using this technique, clay abundance can be measure based on weight-percent of formation rock matrix as shown in Equation 2.7 below:

$$Vol_{dry-clay} = \frac{W_{dry-clay} \rho_{ma} (1 - \phi_{total})}{\rho_{dry-clay}} \quad (2.7)$$

Where

$Vol_{dry-clay}$ = volume percentage of clay abundance

$W_{dry-clay}$ = Weight percentage of formation rock matrix

ρ_{ma} = shaly sand matrix porosity (core analysis)

$\rho_{dry-clay}$ = dry clay density (XRD analysis)

ϕ_{total} = formation total porosity

In addition, Al-Ruwaili (2005) and Shahzad (2005) have indicated that clay volume can be calculated by using the volume of its clay bound water. It is shown in Equation 2.8a and 2.8b below, that the volume of clay bound can be calculated based on cation exchange capacity of clays in which it can be determined from experimental measurement of core samples and brine solution.

$$Vol_{clay-bound-water} = Vol_Q * Q_V * \phi_{total} \quad (2.8a)$$

$$Vol_{clay-bound-water} = Vol_Q * CEC * \rho_{dry-clay} * Vol_{dry-clay} \quad (2.8b)$$

Where,

$Vol_{clay-bound-water}$ = volume of clay bound water

$\rho_{dry-clay}$ = density of dry clay

V_Q = clay cation exchange capacity (miliequivalent per unit volume of pore fluids)

CEC = clay cation exchange capacity (miliequivalent per unit mass of dry clay)

They also proposed that saturation of clay bound water can be obtained from Equation 2.9 based on the volume of the clay bound water obtained from Equation 2.8:

$$S_{cbw} = \frac{Vol_{clay-bound-water}}{\phi_{total}} \quad (2.9)$$

2.3 Effect of Clays on Log Response

Practically, evaluation of log analysis of clean sand formation can be done by using Archie's equation and neutron density cross-plot. However, the existence of clay minerals in shaly sands can complicate the evaluation of log analysis as it can affect the reading of log response; porosity logs (density, neutron and sonic) and saturation logs (resistivity log). The existence of clay mineral in the formation will overestimate the value of porosity and underestimate resistivity reading. In addition, clays minerals could also affect electrical properties, capillary pressure and transmissibility in shaly sand (Al Ruwaili and Al Waheed, 2005). Hence, the investigation in logs response is important in obtaining accurate value of reservoir characteristics. Table 2.8 shows types of logging tool, its response, and effect towards presence of clay minerals.

Table 2.8: Logging Tools and Logs Response (Formation Evaluation Manual, 2012)

Logging Tools	Log Response	Reasons
Gamma ray	– High value of gamma ray for shale formation.	– Give reading on the radioactive contain in shaly sand.
Spontaneous Potential	– Reduce SP deflection.	– As clay in permeable formation produces an electrochemical membrane of opposite polarity of adjacent shale bed.
Density	– Lower shale density at shallow depth.	– Compacting forces are not as great.
Neutron	– Greater apparent porosity than actual effective porosity of reservoir rock.	– Since shales have appreciable hydrogen index.
Sonic/acoustic log	– Increase apparent porosity.	– Interval transit time of clay increase.
Resistivity	– Underestimated the resistivity reading.	– Existence of clay bound water gives the high conductivity value.

Gamma Ray Log

The main application of gamma ray log is to differentiate between shales and other formation and it also use for depth reference tools. Figure 2.8 shows the effect of different lithology on gamma ray logs. It is important to differentiate the value gamma ray reading for difference types of lithology as gamma ray reading can also being effected by borehole diameter and types of drilling mud.

In principal gamma ray log measures natural radioactivity of the formation which consist of uranium, thorium and potassium. It normally reflects shale content of formations due to tendency of radioactive elements to concentrate in shale and clay. Based on study by Shahzad (2005), shale volume estimated by using gamma ray technique can be calibrated by shale volume obtained from experimental measurements.

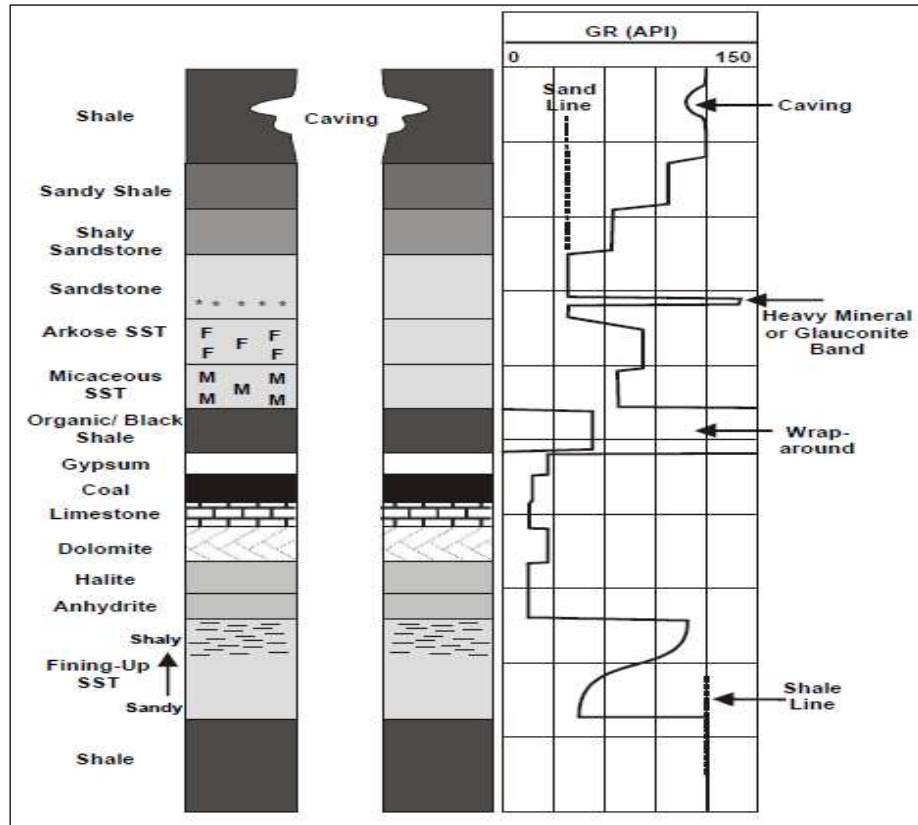


Figure 2.8: Effect of Different Lithology on Gamma Ray Log (Glover, 2012)

The measurements based on naturally occurring gamma ray radiation frequently overestimate clay and shale volume because formation gamma activity not solely related to clay minerals (Adeyemo *et al.*, 2005). Hence, a spectral gamma ray (SGR) is more preferable in differentiate between radioactive minerals in the formation and the radioactive due to clay minerals abundance. It is due to its ability to distinguish between thorium, uranium and potassium values in the formation. Thus, it can be used in determining types of clay mineral.

Spontaneous Potential Log

Spontaneous Potential (SP) log is also used as identification of permeable and non-permeable formation. Its principal is based on spontaneous current flow and potential difference of different formation that provide charge carrier in borehole and formation fluids.

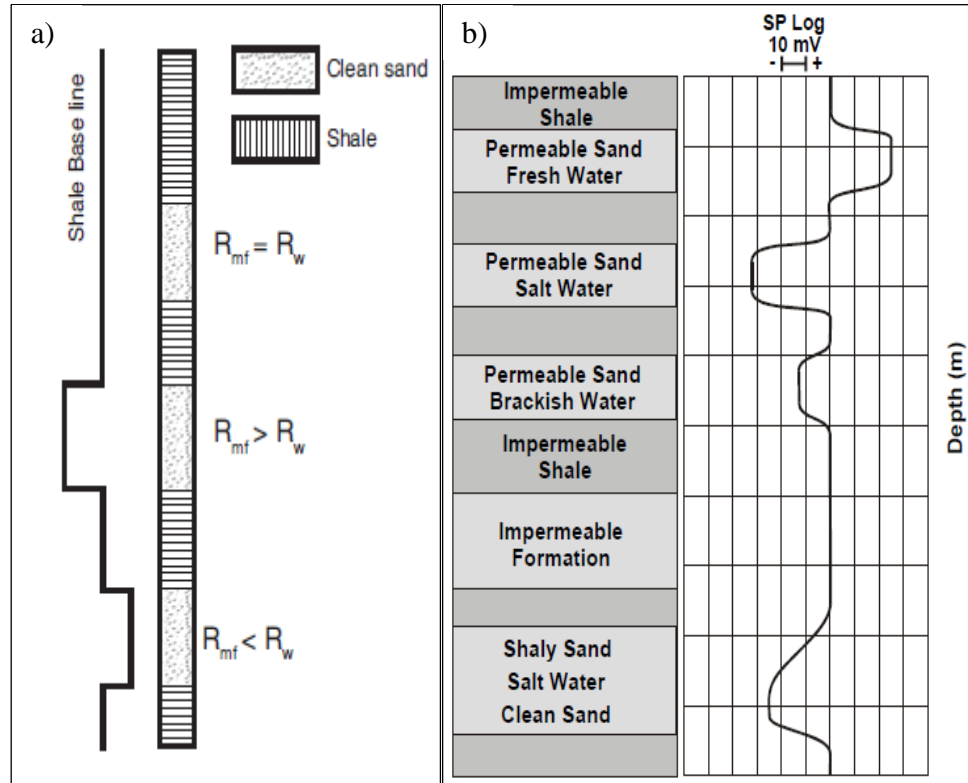


Figure 2.9: SP Curve Behaviour, (a) Behaviour of Clean sand and Shale Interval for Various Formation Salinities (Formation Evaluation Manual, 2012); (b) Typical Response of SP Log (Glover, 2012).

Figure 2.9(a) shows the behaviour of SP curve towards interval of clean sand and shale for various formation water and mud filtrate salinities. Based on the figure, high conductivity formation water will give low reading of resistivity. Salinities difference of mud filtrate and formation water will give a reading on SP log. Meanwhile, Figure 2.9(b) shows that fresh formation water gives positive value of SP reading compare to salt water.

Resistivity Log

Resistivity log can be used to determine permeability and tightness of formation. It can be based on comparison of resistivity reading for shallow, medium and deep depth of invasion. In addition, it also can be used to determine types of fluid in formation either hydrocarbon or water. In the case water, resistivity log gives high low reading of

resistivity log as it has a high conductivity hence electrical property. The effect of clay on conductivity and water saturation will be discussed in details in later section.

2.3.1 Effect of Clays on Porosity

The effect of clay on porosity can be investigated based on porosity logging; neutron, density, and acoustic/sonic logs. Porosity reading is very important on reservoir characterization as it determine the volume of oil in place in the reservoir. Neutron and density logs give the reading of total porosity, compare to acoustic/sonic log, in which it only give a respond on evenly distributed primary porosity. Log reading gives higher porosity value due to presence of clays. This phenomenon is not feasible as total porosity is including the value of clay minerals in the formation in which it is not an effective porosity and it does not content hydrocarbon fluids. Figure 2.10 shows schematic diagram of shaly sand components and its relation to various parameters used in well formation analysis.

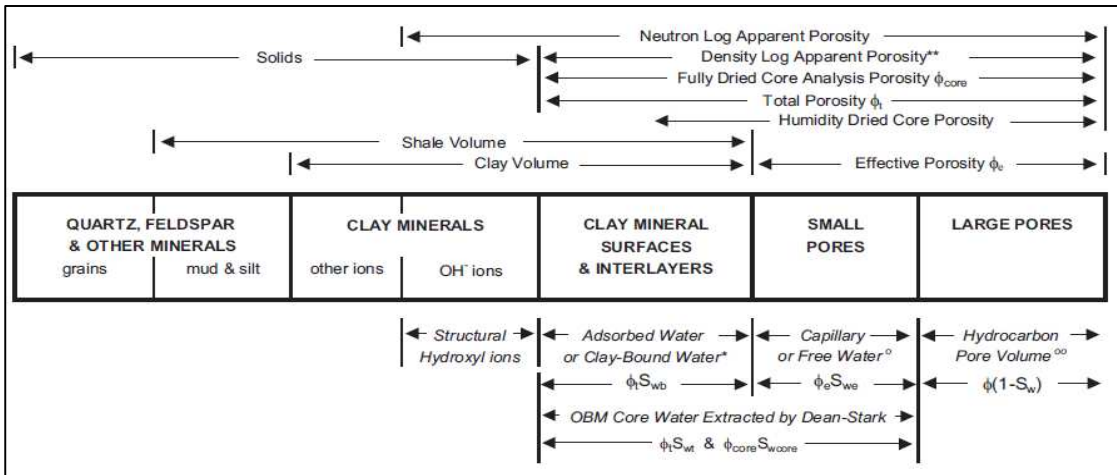


Figure 2.10: Total, Effective and Core Porosity and Their Associated Water Saturations in Shaly Sands (Woodhouse, 2004).

Referring to Hook (2003), effective porosity can be obtained as in Equation 2.10:

$$\phi_{effective} = \phi_{Total} + \phi_{sh} V_{sh} \quad (2.10)$$

From the equation, porosity of shales can be estimated from the value of core porosity or from the value of total porosity calculated from shales as effective porosity is assumed zero in shales. It is more preferable to use total porosity in approximating porosity of shales as estimation of shale porosity in from logs is difficult and mostly erroneous (Al-Ruwaili and Al-Waheed, 2005). In addition, it has been discussed by many authors that estimation of shale porosity from 100% shale section is not accurate due to:

- The selection of a 100% shale section can be wrong
- Measurement of porosity tools can be wrong due to presence of hydrocarbon in that section
- 100% may not exist in the whole shaly sand interval to be evaluated.
- Selection of 100% shaly sand interval may vary from one log analyst to another

Hence, Equation 2.10 is reduced to:

$$\phi_{Total} = \phi_{effective} + \phi_{total} V_{shale} \quad (2.11)$$

Meanwhile, for the clay model, the effective porosity can be obtained by subtracting the total porosity with the volume of clay bound water (Shahzad, 2005):

$$\phi_{Total} = \phi_{effective} + Vol_{clay-bound-water} \quad (2.12)$$

Acoustic/Sonic Log

Since acoustic/sonic log give the reading on primary porosity, hence it responses independent of exact contents of pores spaces such as hydrocarbon, water and dispersed shale. As mentioned in Table 2.5, the existing of shale laminae in the sandstone will give high value of apparent sonic porosity. It is because the interval transit time for clay is higher than sandstone.

Neutron and Density Log

The principal of neutron log response is based on the reading of hydrogen atom content in the formation. Hence, with the existence of clay minerals in the formation, neutron density log will give higher value of porosity reading. It is because neutron log response cannot differentiate between hydrogen atoms reading from formation water or clay bound water. The overestimate value of hydrogen atom will give high value of water saturation. Since the hydrocarbon saturation will be calculated based on water saturation value by $(1-S_w)$, higher value of water saturation will lead to the oversight value of hydrocarbon placement in the formation.

Meanwhile for the density log, its principal is based on the density reading of rock matrix. Generally, the properties of shale vary with formation and locality, with the range of density around 2.2-2.65 g/cm³ with the dispersed clay has lower density than interbedded shales in the pore space (Formation Evaluation Manual, 2012).

Even though, each types of logging tools can give a value for porosity, but due to the complexity of the formation and effect of clays mineral, thus, it is feasible to use the combine log reading with the density and sonic logs in order to have better result (recognised/corrected by additional info) on effect of clay and types of hydrocarbon in lithology.

According to Adeoti *et al.* (2009), volume of shale calculated from neutron-density data is more accurate compare to other method. However, it is affected by the presence of gas and light hydrocarbon in the reservoir, in which this can lead to the inaccuracy in this approach.

2.3.2 Effect of Clays on Conductivity

Effect of clay on conductivity can be linked to the electrical properties of the formation. Since clay minerals have the ability to absorb water to its surface, hence, it can give higher value of formation conductivity. In addition, additional electrical properties of shaly formation can all be due to cation exchange capacity between clays bound water

and free water due to charge imbalance along clay surfaces (Kurniawan, 2005). Hence, CEC can increase conductivity hence reduce the resistivity of formation. Based on the equation proposed by Archie (1942), formation factor (F) for clean water sand can be related with the resistivity and conductivity of the reservoir matrix and fluid as:

$$F = \frac{R_o}{R_w} = \frac{C_w}{C_0} \quad (2.13)$$

Where

F = formation factor

R_o = resistivity of a reservoir rock when fully saturated with aqueous electrolyte of resistivity R_w

C_w = water conductivity

C_0 = conductivity of water saturated sandstone

In addition, formation factor is also being a function of pore structure and pore distribution. It is based on experimental work done by Archie (1942), when at given brine water saturation, the greater the porosity of formation, the lower the resistivity of the formation. This relationship is shown as in Equation 2.14:

$$F = \frac{a}{\phi^m} \quad (2.14)$$

m is a cementation exponent and a is a constant value, which depends upon porosity.

Furthermore, Archie equation in Equation 2.13 can be expressed based on the formation conductivity with a relation to porosity and water saturation.

$$C_t = \phi_{total}^m S_w^n \{C_w\} \quad (2.15)$$

Where

C_t = formation conductivity (from deep resistivity log)

C_w = formation water conductivity

m = cementation factor

n = saturation exponent

Value of m and n can be determined experimentally based on the formation rock and fluid. This Archie equation is used in for the clean sand formation. Hence, for the shaly sand, Archie equation will be modified in order to compensate with the extra conductivity due to effect of clays:

$$C_t = \phi_{total}^{m^v} S_{wt}^{n^v} \{C_w + X\} \quad (2.15)$$

X is a function of excess conductivity in the formation due to present of clay minerals. It can be expressed in terms of shale attributes such as conductivity and volume of shale (Shahzad, 2005). Meanwhile, the electrical properties of formation rock and fluid are indicated as m^v and n^v .

The relationship of formation resistivity factor, F (C_w/C_o) and C_w is shown in Figure 2.11. Clean sand formation gives a straight line relationship, with constant value of formation factor, F . However, the value of formation factor starts to decrease as the formation becomes shalier. The effect of shale component of reservoir rock is on conductivity of water saturated sandstone, C_o , as usually water conductivity, C_w , is presumed to be known (Worthington, 1985).

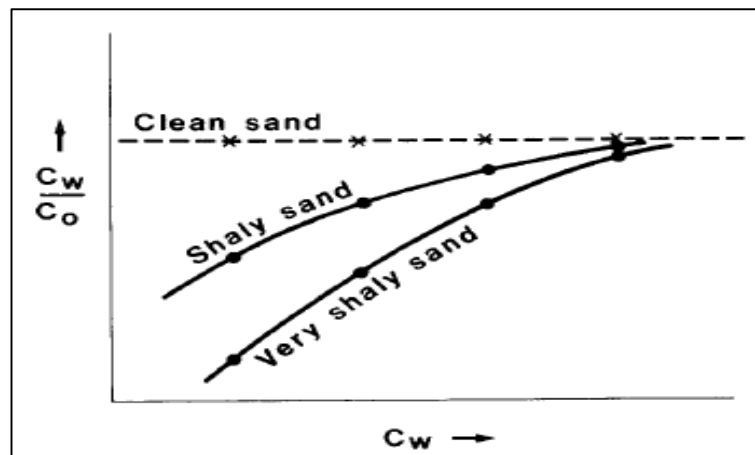


Figure 2.11: Relationship Between Formation Factor and C_w for Shaly Reservoir (Worthington, 1985)

Furthermore, the relationship between C_o and C_w can also be described based on Figure 2.12. Here, the clean sand line is given by the straight line of gradient $1/F$. However, the data is deviated from straight line with the existence of shale effect. The effect of clay minerals in low salinity formation is not uniform compared to high salinity formation, hence it give non-linear relationship zone.

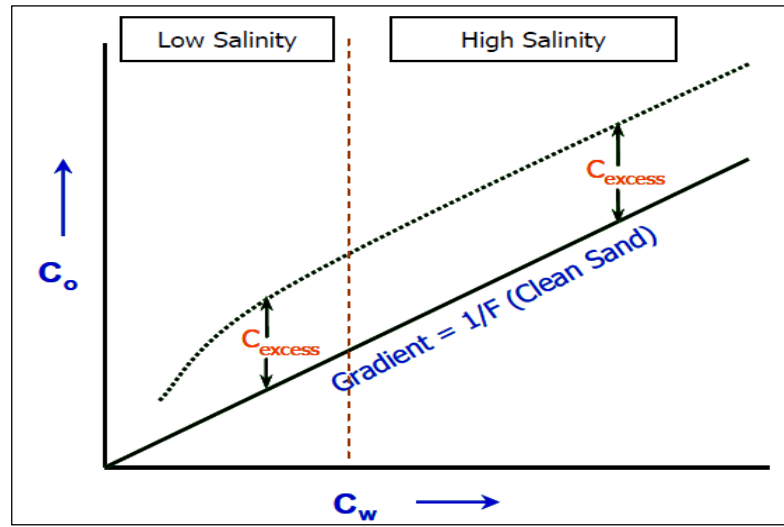


Figure 2.12: Schematic Variation of C_o with C_w for Water-Saturated Shaly Sands (Kurniawan, 2005)

C_{excess} in Figure 2.12 is an indication of excess conductivity that is due to the presence of clay minerals in the formation. The value of excess conductivity increases with the value of C_w in the non-linear zone before it remains constant with increase value of C_w in linear zone. According to the study done by Kurniawan (2005), the linear zone is based on volume of shale model; Simandoux Model. In this model the porosity from density-neutron data and shale fraction determined from GR, SP and other shale indicators have been used in order to calculate the volume of shale.

2.3.3 Effect of Clays on Saturation

The effect of clays on log response can lead to inaccuracy reading on water saturation in the formation. In clean sand formation, water saturation is calculated based on Archie's equation:

$$S_w^n = \frac{a * R_w}{R_t * \phi^m} \quad (2.16)$$

Where,

S_w = water saturation

a = constant value (often taken as 1)

m = cementation factor (varies around 2)

n = saturation exponent (generally 2)

R_w = formation water resistivity

R_t = observed bulk resistivity

However, this calculation is not valid when there is presence of clay in shaly formation. It is because Archie's equation assumes that the formation water is the only electrically conductive material in the formation. Hence, calculation is not valid in the shaly reservoir as the extra conductivity due to the existence of clays in the formation cannot be encounter by this equation. Hence, the reading of water saturation will give an overestimate value. In addition, the resistivity value in this equation can be determined from the resistivity log with hydrocarbon will give high resistivity value compare to formation water as hydrocarbon is non-conductive fluid.

According to Shahzad (2005), water saturation can be calculated based on shale and clay model. Water saturation from shale model can be calculated based on distribution of shale in the formation and also based on total volume of shale. Meanwhile, in clay model, water saturation can be calculated based on Waxman-Smits and Dual Water Model.

Water Saturation Using Shale Model

In shale model, laminated and dispersed shale simplified model are developed in order to calculate water saturation of the formation based on distribution of shale. In addition, total shale relationship can also be calculated regardless of its distribution in the formation.

A. Laminated Sand Shale Simplified Models

In this model, the resistivity of interest zone (in direction of bedding plane) is parallel to the resistivity of shale and cleans sand laminae in the formation, as shown in Equation 2.17 (Shahzad, 2005):

$$\frac{1}{R_t} = \frac{1 - V_L}{R_{sd}} + \frac{V_L}{R_{sh}} \quad (2.17)$$

Where,

R_t = resistivity in the direction of bedding plane

R_{sd} = resistivity of shale laminae

R_{sh} = resistivity of clean sand laminae

V_L = bulk volume fraction of laminated shale

Water saturation can be calculated by implementing the relation between porosity and formation resistivity factor into Equation 2.18:

$$\frac{1}{R_t} = \frac{\phi^2 S_w^2}{(1 - V_{lam})aR_w} + \frac{V_{lam}}{R_{sh}} \quad (2.18)$$

B. Dispersed Shale Simplified Models

According to Shahzad (2005), dispersed shale model is developed to account the extra electrical properties causes pore water and dispersed shale. The relationship is shown in Equation 2.19:

$$\frac{1}{R_t} = \frac{\phi_{im}^2 S_{im}}{a} \left(\frac{q}{R_{shd}} + \frac{S_{im} - q}{R_w} \right) \quad (2.19)$$

Where,

ϕ_{im} = inter matric porosity (includes all spaces occupied by fluids and dispersed shale)

S_{im} = fraction of inter matrix porosity occupied by the formation water, dispersed shale mixture

R_{shd} = resistivity of dispersed shale

q = fraction of inter matrix porosity occupied by dispersed shale

C. Total Shale Relationship

Water saturation based on total shale relationship can be obtained by using Equation 2.20:

$$\frac{1}{R_t} = \frac{\phi^2 S_w^2}{(1 - V_{sh}) a R_w} + \frac{V_{sh} S_w}{R_{sh}} \quad (2.20)$$

Water Saturation Using Clay Model

In clay model, Waxman-Smith and Dual Water Models of electrical conductivity are used for dual conductive pathways formed by pore brine and clay mineral exchange cations (Devarajan *et al.*, 2006).

A. Waxman-Smiths Model

In Waxman-Smiths water saturation determination the extra conductivity is expressed as BQ_v / S_{wt} . This parameter is assumed to be independently in pore spaces of reservoir rock (Waxman and Smits, 1968). Therefore, it indicates that the conductivity of formation remains constant and true conductivity increases with formation shaliness (Shahzad, 2005). Hence, Equation 2.15 becomes:

$$C_t = \phi_{total}^{m^0} S_{wt}^{n^0} \left\{ C_w + \frac{BQ_v}{S_{wt}} \right\} \quad (2.21)$$

Where,

B = specific conductivity of exchangeable cations (mohm/m per meq/cc)

Q_v = clay cation exchange capacity (meq/cc)

m^0 = Waxman-Smits cementation factor

n^0 = Waxman-Smits saturation exponent

Clay cation exchange capacity, Q_v can be obtained by using CEC value of the clay minerals from the experimental measurement:

$$Q_v = \rho_{dry-clay} Vol_{dry-clay} CEC / \phi_{total} \quad (2.22)$$

However, since there is inconsistent experimental results from this model due to the presence of salt-free water at clay-water interface, the Dual Water model have been introduced in order to compensate the lack of previous model (Clavier *et al.*, 1984).

B. Dual Water Model

Dual Water Model is introduced by supplementing water conductivity with conductivity from the clay counterions (Clavier *et al.*, 1984). This model is based on three principles (Shahzad, 2005):

- The conductivity of clay is due to its CEC
- The CEC of pure clay is proportional to the specific surface area of clay
- In saline solutions, the anions are excluded from a layer of water around surface of grain.

In addition to that, Shahzad (2005) indicates that clay is model as consisting of two components; bound water and clay minerals. The amount of bound water varies depending on types of clays; higher for finer clays (with higher specific surface area). This model can be expressed based on formation conductivity:

$$C_t = \phi_{total}^{m^*} S_{wt}^{n^*} \left\{ C_{wf} \frac{S_{wf}}{S_{wt}} + C_{cbw} \frac{S_{cbw}}{S_{wt}} \right\} \quad (2.23)$$

Where,

S_{wf} = formation water saturation (free from and not bound to clay)

S_{cbw} = clay-bound-water saturation

S_{wt} = total water saturation ($S_{wt} = S_{wf} + S_{cbw}$)

C_{wf} and C_{cbw} = conductivity of formation and clay bound water respectively.

m^* and n^* = Dual Water's cementation factor and saturation exponent respectively.

The amount of non-clay water saturation, S_{wf} , in the effective pore-volume can be calculated based on the effective water saturation, $S_{w, effective}$ (Al-Ruwaili and Al-Waheed, 2005):

$$S_{w, effective} = \frac{S_{wf}}{(1 - S_{cbw})} \quad (2.24)$$

2.4 Cross-Plotting

Cross-plots are used especially in complex reservoir by combining different types of logging tools in order to get more accurate reading and do some correction in effect of clay minerals in the formation. In shaly reservoir, clay minerals will shift the cross-plot direction towards the shaly point (Heslop, 2003). Typically, combination of Litho-Density and natural gamma ray spectrometry (NGS) logs, and combination of neutron-density logs are used for clay minerals identification.

2.4.1 Litho-Density Log and Natural Gamma Ray Spectrometry Log (NGS)

Combination of litho-density and Natural Gamma Ray Spectrometry (NGS) log can be used to determine types of clay minerals. In this cross-plot, the petroelectric factor (Pe) is used with potassium (K) and the ratio of Thorium/Potassium (Th/K). The relationship is shown in Figure 2.13 and Figure 2.14 below.

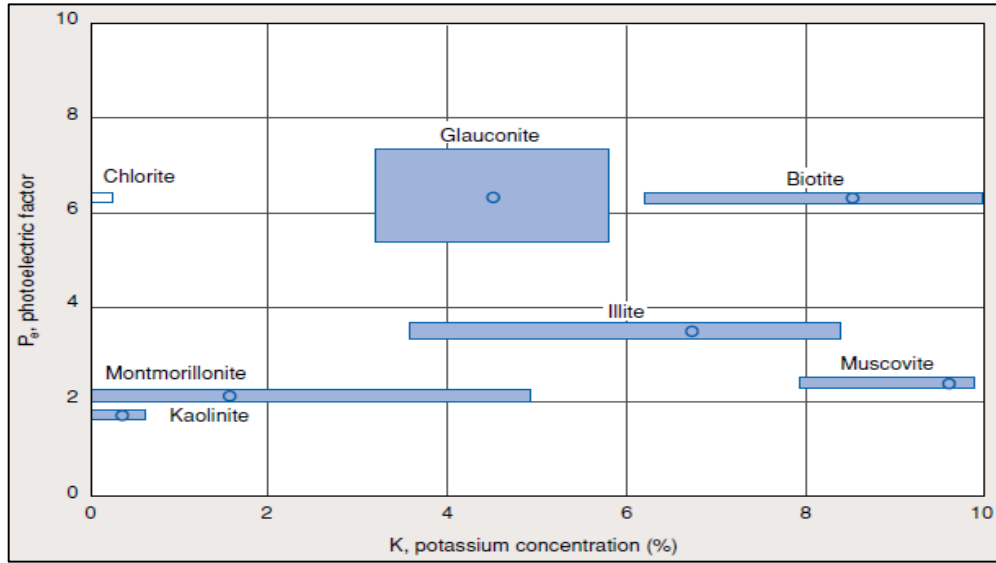


Figure 2.13: Clay Identification Based on Photoelectric Factor (Pe) and Potassium (K) Relationship (Formation Evaluation Manual, 2012)

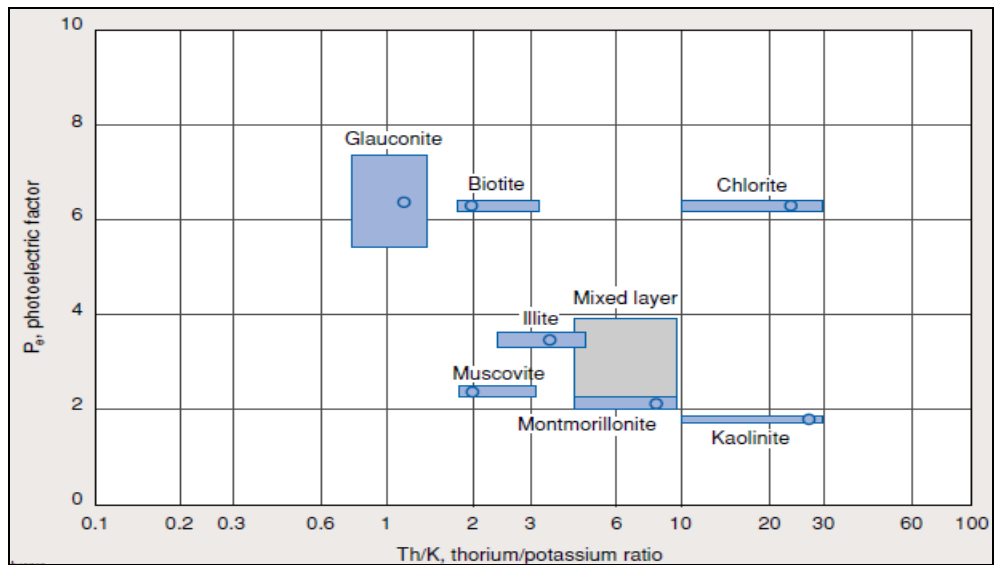


Figure 2.14: Clay Identification Based on Photoelectric Factor (Pe) and Thorium/Potassium (Th/K) Relationship (Formation Evaluation Manual, 2012)

2.4.2 Combination of Neutron-Density Log

Neutron-density cross-plot can also be used in determining shale volume. Heslop (2003) indicates that the combination of neutron-density logs clearly distinguish between sand and shales. From this cross-plot (as shown in Figure 2.15), three points can be defined; quartz point (0% porosity on a neutron sandstone scale and quartz grain density – 2.65 gm/cc), water point (formation water – 100% porosity and 1.0 gm/cc) and shale point.

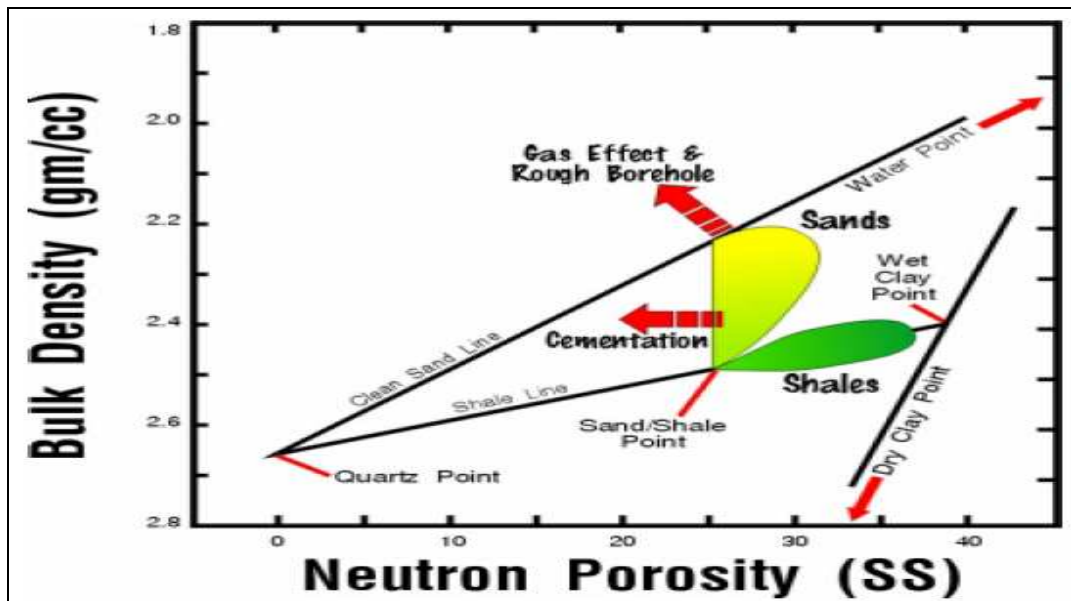


Figure 2.15: Density-Neutron Crossplot (Heslop, 2003)

2.5 Effect of Clay Minerals on Reservoir Performance

The presence of clay minerals in reservoir is not only effecting the evaluation of formation petrophysical properties such as porosity, water saturation and conductivity, but it also effects drilling operations, water injection and acid stimulation work.

This effect is due to swelling properties of clay minerals when they are in contact with water and also the fine migration of the clay particles into formation, which could damage the formation. These phenomena can lead to the permeability reduction of reservoir, either near wellbore or deep into formation, in which it depends on the

invasion of the fine migration into reservoir. In conjunction to that the productivity of the reservoir will be decreased as the reduction of porosity and permeability of the reservoir.

Formation damage due to clays can be classified as that caused by swelling clays and non-swelling clays (Mohan *et al.*, 1993). Swelling of smectite and mixed layer clays are due to changing in clays' ionic conditions and lining the pores in which it will lead to the reduction of effective area of pore system for flow hence reduces formation permeability. In addition, the effect of clay swelling can also be indirect; swelling-induced migration. In this mechanism, the swelling of clay particles lead to the breakage of fines that are in contact with them. Meanwhile, non-swelling clay such as kaolinite and illites tend to disengage from rock surface and migrate due to its ease dispersion and suspension stability. This mechanism is known as migration. The migrating particles can get trapped in pore throats thus causing a reduction in permeability. Figure 2.16 shows schematic diagram for these three mechanisms of permeability reduction in sandstone containing swelling and non-swelling.

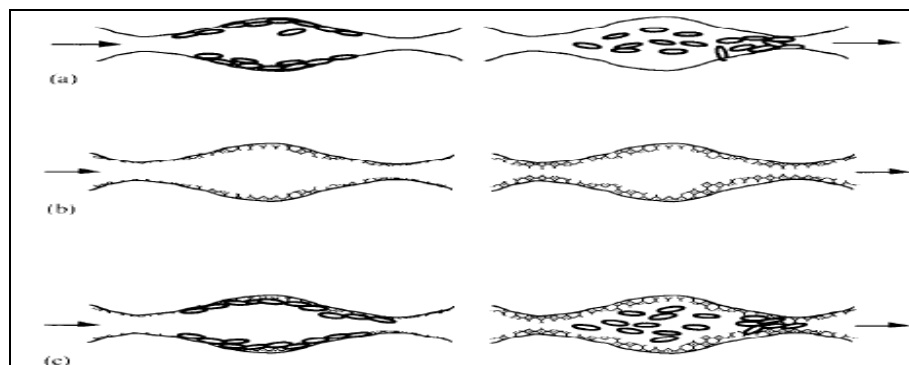


Figure 2.16: Mechanisms of Permeability Reduction Caused By Clays in Porous Media (A) Migration, (B) Swelling, (C) Swelling-Induced Migration (Mohan *et al.*, 1993)

According to Production Technology Manual (2011), magnitude of permeability reduction due to interaction between formation and fluid interaction depend on clay chemistry and morphology, amount of clay and chemistry of mud filtrate (pH and salinity).

2.5.1 Fine Migration

Fine migration is generated by deformation of rock during compression and dilatation. It involves production of mobile, very small, solids into the formation due to release of clay from the pore system or due to invasion of fine particle (clays) in drilling fluids into formation. Civan (2007) proposes three primary sources of fine particles in petroleum bearing formation:

- Invasion of foreign particles carried with the fluids injected for completion, workover, and improved recovery purposes.
- Mobilization of in situ formation particles due to the incompatibility of the fluids injected into porous media and by various rock-fluid interactions.
- Production of particulates by chemical reactions, and inorganic and organic precipitation.

Well productivity impairment is more severe in the area of young unconsolidated sediments especially when production rate is increased too quickly (Production Technology Manual, 2011). It is because high production rate can lead to the high colloidal forces between hydrocarbon production and formation.

2.5.2 Drilling Operations

In drilling operations, the impairment between drilling fluids and formation should be taken into account. Damage of formation permeability can be due to the mud filtrate and penetration of the drilling mud solids into the formation (Krueger, 1986). In addition, mixing of incompatible drilling fluid with clay minerals leads to swell of clays hence leads to the stuck pipe problem.

Clay minerals are used as an additive in drilling fluid as for viscosity, density and filtration control (Drilling Engineering Manual, 2005), hence the exact amount for mixing the additive into drilling fluid are crucial as to prevent the excessive or underweight of the added additive. In addition, Khodja *et al.* (2010) indicates that mud viscosity can affect the dispersion and swelling of shales and decreases the diffusion velocity in porous media.

In addition, Oort (2003) states that there are three mechanisms that can lead to the borehole instability due to the drilling fluid:

- Elevation of the pore pressure due to mud pressure invasion, reducing the effective stresses.
- Elevation of the swelling pressure (such as due to unfavourable cation exchange at clay sites), reducing the effective stresses.
- Chemical alteration and weakening of cementation bonds. This mechanism adjusting shale strength and failure parameters (such as cohesion and friction angle).

Moreover, the effect of clays on mud filtrate will give severe impact to the near wellbore permeability as in water-based mud, the salinity of mud filtrate is usually less than the formation water. Hence, the invasion of different fluid causes alteration of dispersed clay in formation (Stewart and Mahmoud, 2012). Thus, it is important to choose the types of mud to be used in drilling operations in order to reduce the effect of clay minerals in the formation. The depth of invasion of mud filtrate and formation damage can be determined by resistivity log.

2.5.3 Water Injection

Water injection is implemented in order to maintain reservoir pressure and increase sweep efficiency of hydrocarbon production. The effect of clay swelling during water injection is more severe when there is incompatible mixing fluid between injection fluid and formation water. The swelling of clay can lead to the reduction in permeability near the wellbore. In addition, the effect of clay minerals during water injection is also based on the difference in pH between injection and formation water (Kantorowicz *et al.*, 1986). This phenomenon can cause the release of clay particles and clay swelling due to the alteration of activity of cations in solution. In addition, difference in salinity and shear by moving pore water can also leads to the formation damage, as it can cause the release of weakly bonded clays, feldspar and other minerals in pore system (Krueger, 1986).

Moreover, the used of formation water as an injection fluid can also lead to the migration of clay minerals into the formation during water injection. It is because the formation water usual contains fine-grained particles such as clays and other minerals. The injection of clays into the formation can leads to the clogging of pore throat and also permeability impairment.

2.5.4 Stimulation

The effect of clay during stimulation job is also important as different types of clay will have different effect on types and concentration of acid used during stimulation job. Simon and Anderson (1990) indicates acid stability of the clay minerals is vital during acid stimulation job as it is to prevent the effect of clay mineral structure towards the exposure of the types of acid used in stimulation job.

Many common minerals in sedimentary rocks such as clay minerals, siderite and ankerite are readily soluble in hydrochloric or hydrofluoric acids. Pittman and Thomas (1979) specifies that these minerals are also known as iron-bearing minerals, in which when dissolved into acid it can release iron which will precipitate in the form of a ferric hydroxide gel. Ferric hydroxide gel might block the pore throats and lower the permeability. In addition, in reference to their experimental work, Pittman and Thomas have summarized the relative response of common clay minerals to hydrochloric and hydrofluoric acids as shown in Table 2.9.

Table 2.9: Relative Solubility of Clay Minerals in Common Treatment Acids (Pittman & Thomas, 1979)

Clay Minerals	Type of Acids	
	Hydrochloric Acid	Hydrofluoric Acid
Kaolinite	Slightly soluble	Slightly soluble
Illite	Slightly soluble	Slightly/moderately soluble
Smectite	Slightly soluble	Moderately soluble
Chloride*	Highly soluble	Highly soluble
Mixed Layer	Variably soluble	Variably soluble

*releases iron to system with dissolution

Moreover, according to Production Technology Manual (2011), majority acid stimulations of clastic reservoirs are carried out with mud acid (mixture of hydrochloric (HCl) and hydrofluoric (HF) acids). This acid is capable to dissolve minerals such as clays and mica, in which these minerals will undergo a series of reactions that result in precipitation of silica gel (Si(OH)_4); hydrated form of silica.

2.6 Summary on Literature Review

The presence of clay minerals in reservoir leads to inaccurate estimation of water saturation, resistivity and porosity of the reservoir, hence leads to vague values of total gross volume of the reservoir and the estimation value of hydrocarbon-in-place.

From the literature, there are lots of effects of clay minerals in reservoir properties and characterization. Hence, it is feasible to study the occurrence and characterization of clay minerals in details. Even though there are plenty of models have been introduced but no one models that can fixed all types of clay minerals problem in the reservoir. In addition, some of the calculations that need to be used for correction of clay minerals appearance can be inaccurate as the distribution and types of clay minerals are not look into details. Hence, the cross-plotting has been used in order to have better indication of volume of shale and identification of types and distribution of clay minerals.

Moreover, the effect of clay minerals in terms of reservoir performance is also crucial. As the presence of clay minerals can leads to permeability impairment, hence reducing productivity of reservoir. Permeability reduction is due to fines migration and formation damage near wellbore region. Besides, drilling operation, water injection and acid stimulation activities can also leads to reduction in reservoir performance due to the effect of clay minerals.

CHAPTER 3

METHODOLOGY/PROJECT WORK

Research methodology is divided into log interpretation, clay minerals characterization, and analysis and critical reviews on effect of clay minerals on reservoir characteristics and performance. In log interpretation, the methods used for volume of shale calculation based on gamma ray, density-porosity and resistivity logging tools have been examined. In addition, types of clay minerals can also be identified by using spectral gamma ray (SGR) logging tool. Next, the types and properties of clay minerals are identified by using thin section, polarize microscope, SEM and FESEM/EDX. In addition, the investigation of the effects of clay minerals on water relative permeability, saturation, capillary pressure, logs response and formation damage are also being introduced.

3.1 Log Interpretation

In log interpretation, the log readings of gamma ray (natural and spectral), density, neutron and resistivity are taken from the case study done by Hussein and Ahmed (2012) on the shaly reservoir in Palouge-Fal Oilfield, Sudan.

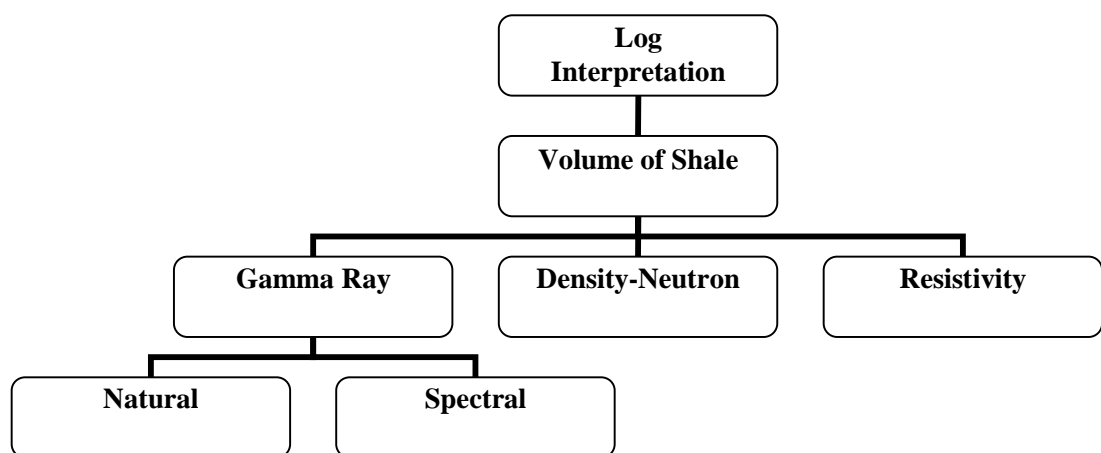


Figure 3.1: Log Interpretation (Volume of Shale) Flowchart

3.1.1 Gamma Ray Log

Gamma ray reading can be based on natural gamma ray or spectral gamma ray reading, in which natural gamma ray is the technique used in determining volume of shale, meanwhile spectral gamma ray is used in identify types of clay minerals.

Natural Gamma Ray

Procedures for value of volume of shale calculation based on Natural Gamma Ray log are:

1. The maximum and minimum values of gamma ray are identified.
2. Then the gamma ray values at the interest zone are determined.
3. Next, the values of gamma ray index are calculated based on the Equation 2.5:

$$V_{sh} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

4. The cut-off value of gamma ray is applied in order to differentiate between permeable and non-permeable zone.

Note: The differentiation between these zones is important as it will be used for the next calculation (volume of shale calculation based using neutron-density log).

Spectral Gamma Ray

Procedures for types of clay mineral identification based on Spectral Gamma Ray log are:

1. The values of Potassium, K (%) and Thorium, TH (ppm) on spectral gamma ray are determined.
2. The graph of Thorium versus Potassium is plotted.
3. Next, the plotted graph is compared with the graph of Thorium and Potassium cross-plot (as shown in Figure 18) in order to determining the types of clay minerals.

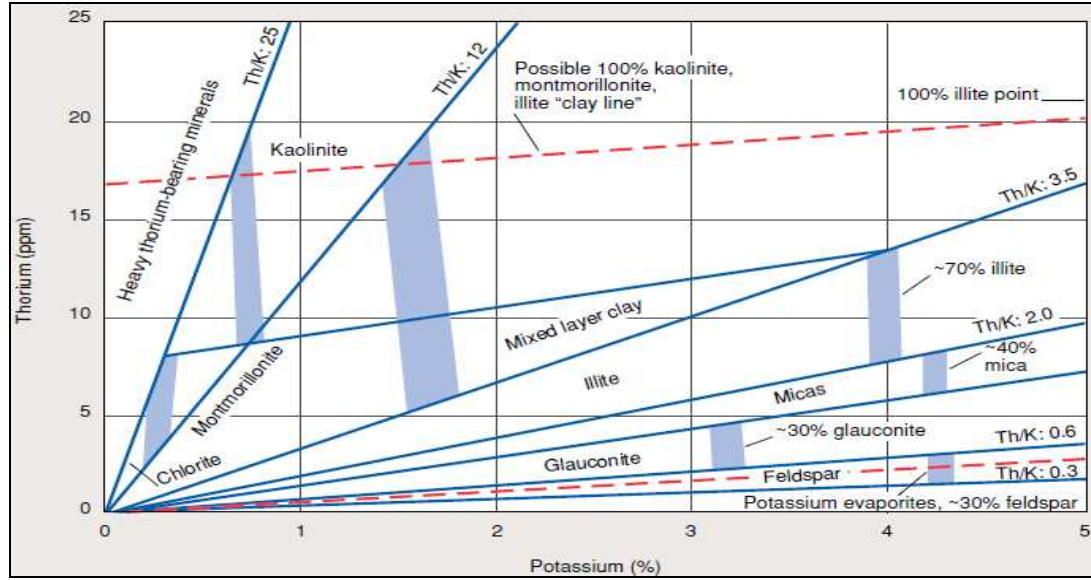


Figure 3.2: Clay Identification Based on Thorium and Potassium Relationship
(Formation Evaluation Manual, 2012)

3.1.2 Neutron-Density Log

Volume of shale can be determined based in neutron and density logs base on Equation 3.1 (Adeoti, 2009):

$$V_{sh} = \frac{\phi_N - \phi_D}{\phi_{NSH} - \phi_{DSH}} \quad (3.1)$$

Where,

ϕ_N = neutron porosity in the sand

ϕ_D = density porosity in the sand

ϕ_{NSH} = neutron porosity in adjacent shale

ϕ_{DSH} = density porosity in adjacent shale

Procedure of volume shale calculation based on neutron-density log:

1. First, the values of neutron porosity at the sand formation from neutron log are determined.

2. Next, the values of density porosity at the sand formation from the density log are determined by using Equation 3.2:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (3.2)$$

Where,

ϕ_D = porosity from the density log

ρ_{ma} = density of rock matrix

ρ_b = bulk density read from the log

ρ_f = fluid density

3. Finally, step 1 to 3 is repeated by using the values of neutron and density logs at shaly formation.

3.1.3 Resistivity Log

Resistivity log can also be used to calculate the volume of shale. Equation 3.3 (Adeoti, 2009) is used for this purpose:

$$V_{sh}(resistivity) = \frac{\log(RES D) - \log(RES D_CLN)}{\log(RES D_SHL) - \log(RES D_CLN)} \quad (3.3)$$

Where,

RES D = resistivity log reading from zone of interest

RES D_CLN = resistivity log reading from clean sand

RES D_SHL = resistivity log reading from shale

Procedures for volume of shale calculation based on resistivity log reading are:

1. The resistivity log reading from the interest zone is determined.

Note: the reading of resistivity log for this zone is taken at the permeable zone as has been indicated from the previous method (cut-off from gamma ray log).

2. Then the readings of resistivity log from the clean and shaly sand are determined.

3.2 Clay Minerals Characterization

Clay mineral characterization can be analysed based on thin section, polarized microscope, SEM and FESEM/EDX as shown in Figure 3.3. The purposes and application of each tool is summarized in Table 3.1. In this research, clay minerals characterization is based on the samples taken from Balingian Sub-Basin, Mukah, Sarawak.

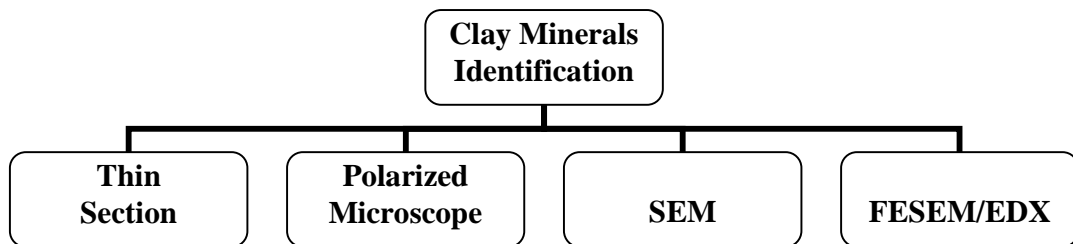


Figure 3.3: Flowchart of Clay Mineral Identification

Table 3.1: Tools Used in the Clay Minerals Characterization and Its Purpose

Analysis	Purposes
Thin Section	To determine the texture, sorting, fabric and porosity of clay minerals.
Polarized Microscope	To detect amorphous substances in porous media.
Scanning Electron Microscope (SEM)	To examine morphology/structure/crystal size of clay minerals.
Field-Emission Scanning Electron Microscope/Energy Dispersive X-Ray (FESEM/EDX)	To examine high-resolution of imaging/x-ray microanalysis of clay minerals. <ul style="list-style-type: none"> - Surface structural analysis - Elemental materials analysis

3.2.1 Thin Section Analysis

Thin section is the study of texture, sorting, and porosity of reservoir rock. In conjunction of investigating clay minerals micro and macro structures, the thin section is analyzed under polarized microscope in order to have better understanding of clay mineral characterization. Thin section is prepared in 0.03mm thick slice of rock attached to a glass slide with epoxy.

3.2.2 Polarized Microscope Analysis

Polarized microscope is used to analyse the thin section; to detect the amorphous substance and distinguish crystalline structure. There are two types of beams can be used; Plain Polarize Light (PPL) and Cross Polarize Light (CPL). In this study the magnification of 100 μm and 200 μm are used in order to see the image of thin section.

3.2.3 SEM and FESEM/EDX Analysis

Scanning Electron Microscope (SEM) Analysis is used to analysis the abundance, size, topology and morphology of the clay minerals. From the SEM analysis the typical structure of clay minerals can be obtained. In this study Field-Emission Scanning Electron Microscope/Energy Dispersive X-Ray (FESEM/EDX) is also used in order determine more high-resolution of clay structures and also its chemical elementary.

3.3 Effect of Clay Minerals

The study on the effect of clay minerals will be discussed in details based on water relative permeability, saturation, capillary pressure curve, logs response and finally the formation damage. The purposes of this study are to see the effects of clay minerals on these parameters, and how to identify its impact and to eliminate the problem associated with clay minerals. At the end, this investigation is related to reservoir performance in terms of permeability and productivity of the reservoir.

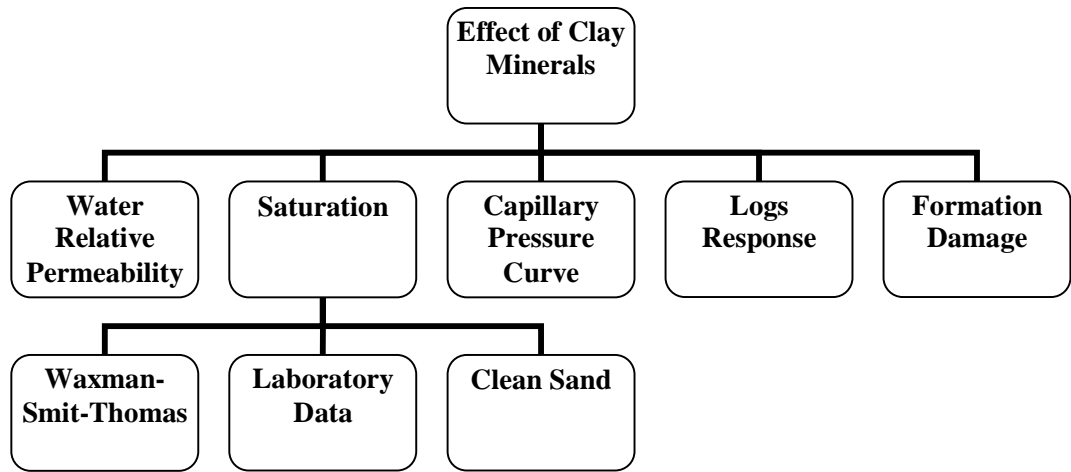


Figure 3.4: Flowchart of Identification of Effect of Clay Minerals

CHAPTER 4

RESULTS AND DISCUSSION

In this section, the results and discussion are based on the data taken from the internal reports and training materials of PCSB and samples of clay minerals taken from Balingian Sub-Basin, Mukah, Sarawak. This section is divided into log interpretation, clay minerals characterization and the effects of clays on water relative permeability, saturation, capillary pressure curve, logs response and formation damage.

4.1 Log Interpretation

In this report, the feasibility of volume of shale calculation based on log interpretation is investigated. Appendix A shows the logs response of gamma ray (natural and SGR), resistivity, neutron and density logging tools. The volume of shale calculation from three difference logs is based on calculation at the interest zone in Zone A (1292.24m).

4.1.1 Gamma Ray Log

The reading of gamma ray is shown in Track 2 (Appendix A) for both types of logging tools, natural gamma ray and spectral gamma ray. From the gamma ray reading it shows that the natural gamma ray gives the overestimate value of gamma ray, hence the volume of shale. It is due to the fact that natural gamma ray can only measure the total radioactive in the formation regardless the sources of radioactive from other minerals in the reservoir. Based on the sample calculation shows in Appendix G, the volume of shale calculated is 0.75. In this study, the spectral gamma ray reading is used to identify the types of clay minerals based on thorium (ppm) and potassium (%) relationship. Generally, spectral gamma ray can distinguish the source of radioactivity in the formation hence giving better gamma ray reading. It is shown in Track 2 (Appendix A) that the reading of spectral gamma ray gives lower gamma ray value compare to natural gamma ray. Appendix D, Figure D-1 shows the plot of SGR reading (thorium versus

potassium) based on SGR reading in Appendix C. For the clay minerals identification, this plot is compared with the plot of thorium-potassium cross-plot in Figure D-2. From the plot it shows that the types of clay minerals presence in the reservoir are mainly mixed layer clay. Some of the minerals are glauconite and potassium feldspar in which this gives the indication of high value in natural gamma ray reading.

4.1.2 Neutron-Density Log

The log reading for neutron and density logs are shown in Track 4 (Appendix A). Appendix E shows the calculation of porosity reading based on density and neutron logs. The volume of shale calculated at Zone A is 0.45, in which this value is lower than calculated value from natural gamma ray logs. Hence, the use of combination of logging tools in this case neutron-density can give better indication of volume of shale. However, the use these logging tools can lead to the inaccuracy value of porosity calculation in presence of clay minerals. It is because neutron log will give higher value of porosity as it is due to the hydrogen index from the clay bound water.

4.1.3 Resistivity Log

The log response for resistivity log is shown in Track 3 in Appendix A. Appendix F shows deep, medium and shallow resistivity readings. The value of shale calculation from resistivity log is 0.50, in which the value is almost the same with the calculation using neutron-density methods. This method also gives a lower shale volume compare to natural gamma ray. Even though this method is also feasible to be used in volume of shale calculation, the effect of clay minerals in term of formation's electrical properties can lead to the inaccuracy of resistivity reading. It is because clay minerals add more conductivity to the reservoir hence gives underestimated value of resistivity reading. This phenomenon will affect water saturation calculation in later stage.

4.2 Clay Minerals Characterization

Clay mineral characterisations are based on thin section, polarized microscope, SEM and FESEM/EDX analysis. The used of difference methods are important in order to have better understanding on clay minerals identification.

4.2.1 Combination of Thin Section and FESEM/EDX Analysis

Thin section is a petrography technique is used to examine the texture, sorting, fabric and porosity of samples of formation. The combination of thin section and Field-Emission Scanning Electron Microscope/Energy Dispersive X-Ray (FESEM/EDX) will give better understanding towards pore and surface structure, and elementary of the minerals. Figure 4.1 to 4.3 show the results of thin section and FESEM/EDX analysis base on five difference samples.

Figure 4.1(a) shows clay mineral sample of SH 13. From the thin section study, the sample shows microporosity of the clay minerals structure. Meanwhile, for FESEM analysis, it shows dissolution of potassium feldspar and flocculation of kaolinite clays; some of its plates are arrangement in edge-to-face towards each other. This can be an indication of the separation of the charges at surface and edge of clay particles.

Meanwhile, Figure 4.1(b), SH 7 sample shows laminated shale and sand formation. From this figure the investigation on the difference between the pore structure of clay mineral and sandstone can be investigated. The clay minerals thin beds show the microporosity comparing to porosity of the sandstone lamination. The sandstone lamination has bigger porosity with the interconnected pore space, in which it indicates good permeability of that particular formation. The FESEM image for this sample also shows the flocculation of kaolinite.

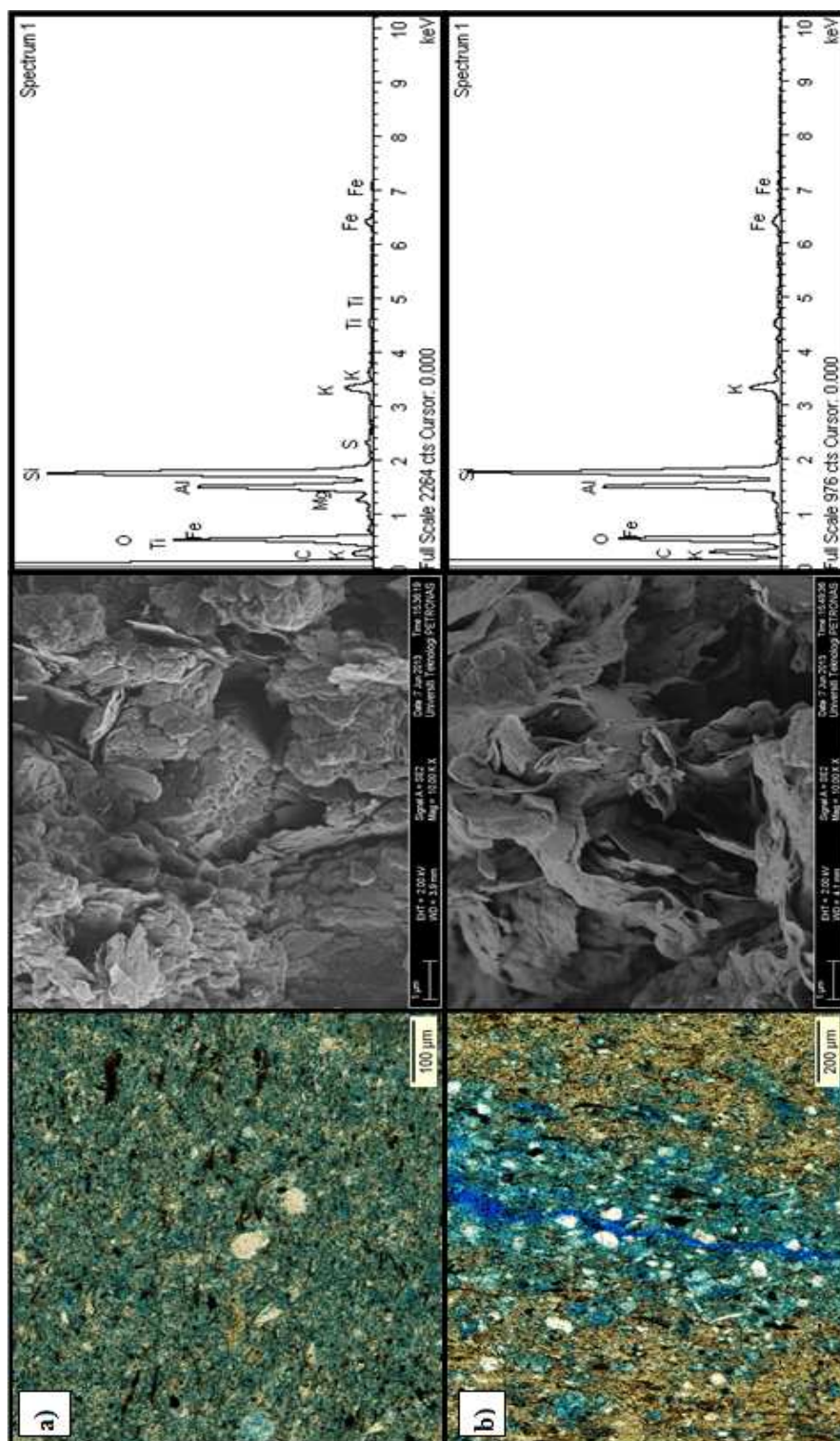


Figure 4.1.1: Images of Clay Mineral Samples a) SH 13 and b) SH 7 under Thin Section and FESEM/EDX

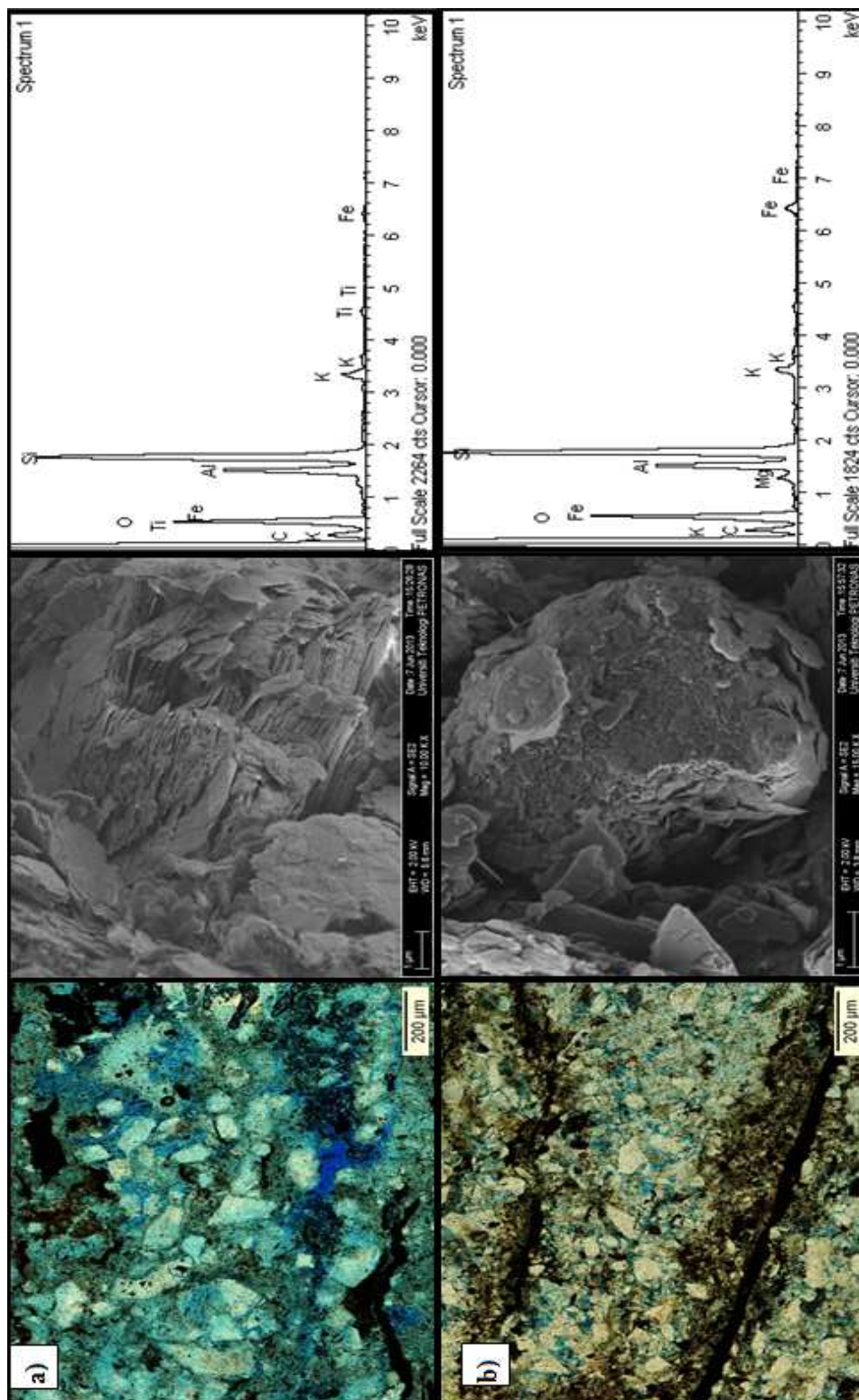


Figure 4.2: Images of Clay Mineral Samples a) SH 3 and b) SH 11 under Thin Section and FESEM/EDX

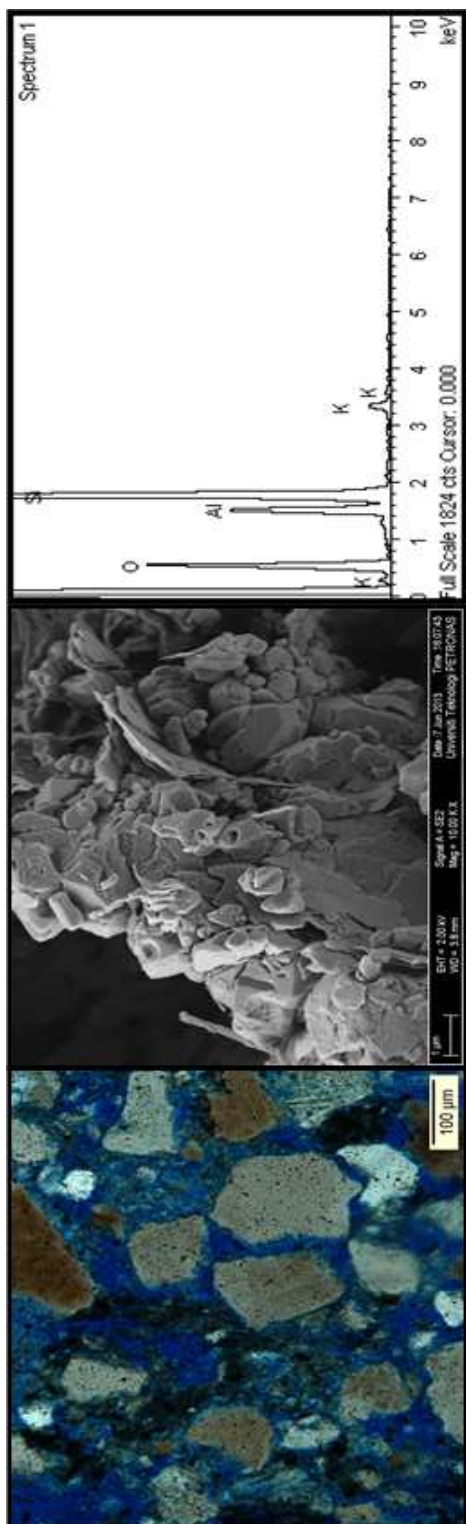


Figure 4.3: Image of Sandstone Sample (SS1) under Thin Section and FESEM/EDX

Next is the thin section image taken at the sandstone lamination which located nearer to the clay minerals (as shown in Figure 4.2 (a): SH 3 sample). The thin section shows that the grain size are located close to each other, however it has a very low porosity and the pore is not interconnected (middle area). Meanwhile, FESEM image shows the platelets structure of kaolinite in this structure. This can be the reason of the poor porosity and permeability in between grain size as the presence of kaolinite clay mineral can lead to the fine migration hence blocking the pore space.

Sample (SH 11) is the fourth sample used for this investigation (as shown in Figure 4.2 (b)). This thin section shows the area of sandstone and invaded of clay minerals next to the sandstone lamination. The area near to the clay minerals formation has poorer porosity compare to the middle area of the thin section. In addition, both images from thin section and FESEM show the dissolution of chlorite clays.

Finally, Figure 4.3 shows the result of sandstone sample (SS1). The result from this figure can be used as the comparison between the laminated formation (sandstone/clay) and also the difference between clay formation and sandstone formation. The figure shows the formation has great grain size with good porosity and permeability. Meanwhile, FESEM image show the quartz overgrowth and the precipitation of pyrite (cementation).

Table 4.1: Summary of Atomic Percentage of Chemical Elements

Chemical Element	Atomic Percentage (%)				
	SH11	SH13	SH3	SH7	SS1
C	30.77	19.88	24.87	25.68	-
O	51.71	58.05	56.65	53.09	69.77
Mg	0.54	0.55	-	-	-
Al	4.07	6.33	4.82	6.55	6.45
Si	11.56	12.97	12.38	12.86	22.77
K	0.60	1.16	0.88	1.29	1.01
Fe	0.74	0.68	0.17	0.53	-
S	-	0.20	-	-	-
Ti	-	0.18	0.22	-	-

Table 4.1 shows the summary of atomic percentage of chemical elements in the samples. Based on the table, sandstone sample (SS1) has high percentage of silicon (Si) and oxygen (O), this result is as expected as the sandstone contains quartz (SiO_2) mineral. On the other hand, all the samples (SH samples) have high percentage of aluminium (Al), silicon (Si) and oxygen (O). This confirms that there is the presence of clay minerals in these samples. In addition, the traces of magnesium (Mg) and iron (Fe) can give an indication of the presence of chlorite groups of clay minerals especially in sample SH 11 and SH 13. Meanwhile, the traces of potassium (K) can be due to the presence of illite group or potassium feldspar mineral in the formation. Moreover, the carbon (C) is from the traces of hydrocarbon in the formation as also can be seen from the thin section (black spot). There are also the small percentages of sulphur (S) and titanium (Ti), the traces of titanium indicated the heavy metal component.

4.2.2 Scanning Electron Microscope (SEM) Analysis

Scanning Electron Microscope (SEM) is used to examine the morphology and structure of clay minerals. Figure 4.4 to 4.6 show difference types of clay minerals occurrence in the reservoir; a) kaolinite, b) illite, c) chlorite, d) smectite and e) mixed layer of illite-smectite.

Figure 4.4(a) shows structure of kaolinite clay minerals which is pseudo-hexagonal plates or booklet and stack above each other. Due to the structure of kaolinite, it is easier for its structure to break, hence leads to the potential of fines migration and can cause pore throat blocking therefore permeability impairment. The effect of fine migration due to clay minerals will be discussed later. From the literature, the kaolinite group has low cation exchange capacity and not expanding when in contact with water, hence it does not have swelling properties.

Next is illite group of clay minerals. Figure 4.4(b) shows the structure of illite where it has fibrous structure growing coating the grain. Illite also has the same characteristics as kaolinite group, as it has a potential of fines migration and it is not expanding with presence of water even though it has low to moderate cation exchange capacity.

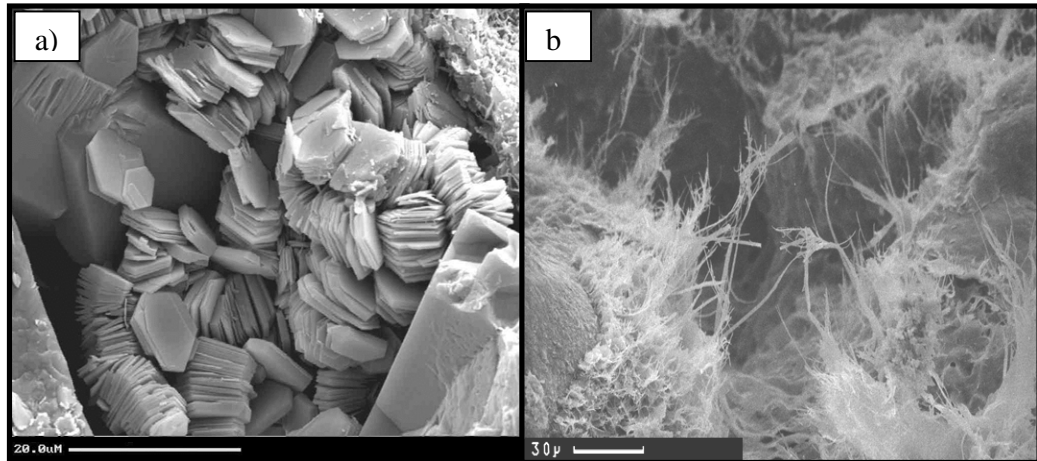


Figure 4.4: Images of a) Kaolinite and b) Illite under SEM Analysis (PCSB, n.d)

Furthermore, the structure of chlorite group of clay minerals is shown in Figure 4.5(a). This type of clay mineral also has a potential of fines migration and low cation exchanger capacity. Even though chlorite is not expanding, but its microporosity can be filled by water by having high capillary pressure. Chlorite group has platelets and honeycomb structure, in which it is identified as a coating on sandstone grains. Referring to the literature review, chlorite group is highly soluble with the hydrochloric and hydrofluoric acid used in the stimulation work. Hence, more precaution should be taken in conducting the stimulation job in the area of chlorite clay minerals as it is acid sensitive and it can release the iron into the formation by dissolution.

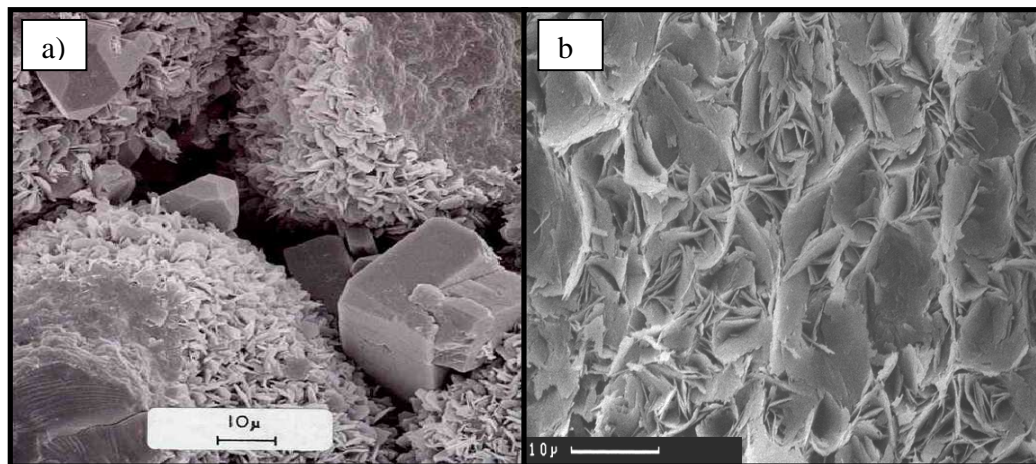


Figure 4.5: Images of a) Chlorite and b) Smectite under SEM Analysis (PCSB, n.d.)

Moreover, the group of clay minerals that has been investigated is smectite group. This is the most important types of clay minerals as it has swelling properties by having high cation exchange capacity and it can expand with the presence of water. Figure 4.5(b) shows the structure of honeycomb and cornflake of smectite group. Besides of swells, smectite group can also lead to the fine migration. It is due to the fact that the expansion of smectite group during swells will detach the bonding between smectite clay and grain surface. In addition, clay minerals can also occur by mixed layer, for example mixed layer of illite-smectite in Figure 4.6. The figure shows the coating of smectite group on the rock grain and the bridging of illite group between the rock grains. The mixed layer types of clay minerals is more severe, as for this example, the exposure of smectite group to fresh water will cause the smectite to swell and choke off the pore throats.



Figure 4.6: Images of Illite-Smectite (Mixed Layer) under SEM Analysis (PCSB, n.d.)

4.3 Effect of Clay Minerals

In this section the effect of clay minerals in reservoir characterization and performance in terms of water relative permeability, saturation, capillary pressure curve, logs response and formation damage will be discussed.

4.3.1 Effect of Clay Minerals on Water Relative Permeability

In this part, the effect of clay on minerals on water relative permeability will be discussed based on two phenomena which are due to fine migration and clay swelling.

The data from this study are taken from internal reports and training materials of PCSB. The relation between water relative permeability and water saturation will be examined.

Effect due to Fine Migration

The graph of relative permeability versus water saturation is shown in Figure 4.7. In this figure, water relative permeability decreases toward the increases of water saturation. At the point right before water relative permeability reduction can be indicated as the point of interstitial velocity that fine migration begins to occur. When the interstitial velocity is reached, the fines minerals such as clays and feldspar will start to lose its bonding from the grains surface. Hence, the fine minerals start to migrate through the formation. These mobilized fine minerals will block the pore throats leading to permeability reduction in the formation.

Initially, reservoir is at the initial water saturation of (S_{wi}) in which theoretically this value should be the same as the end point value of oil relative permeability. The end point value indicates the limit saturation of respective phases (water or oil) and the irreducible water saturation or residual oil saturation of the reservoir. During drilling operation, there will be an invaded of aqueous based drilling fluid into near wellbore formation. Due to fine migration during drilling operations, the irreducible water saturation of this region will increase as the capillary trapping phenomena near the wellbore region. This is shown in the figure that the water saturation of (S_{wi}) is more that the end point of oil relative permeability. In addition, the relative permeability is reduced substantially due to increase tapping of invaded aqueous phase from drilling fluid.

During the production, the oil production decreases with increases of production of water throughout of well lifetime. At earlier stage of production, water relative permeability is increasing as there is more flow of water in the formation, as it is displacing oil in the reservoir. The increases in well production rate will lead to the high colloidal force between the hydrocarbon production and minerals in the formation. Hence, it can release fine particles from the pore surface. The mobilised particles will be flow with the water in the formation until the point that the particles brought by the

water will supersaturated and the flow of water starts to decrease. Then, the fine particles will strand at the pore space and can also block the pore throat. The blocking of pore throat will leads to the assembling of water at the pore space. This phenomenon can lead to reduction of water relative permeability.

Moreover, the effect of fine migration can also be discussed based the water injection operation. In this case the effect of fine migration usually induces by the injection of low salinity water. The same phenomenon as per discussion above will occur for the effect of fine migration during water injection. The reduction of water relative permeability will happen in water sweep zones hence diverts water flow to non-swept zones.

In addition, it also leads to the diversion of water flow from initially more permeable to less permeability layers. Increase in oil and water mobility ratio facilitates the fluid diversion caused by fine migration. The released fines captured by neighbouring pore throats hence reduce relative permeability of water.

Effect due to Clay Swelling

Comparing to the effect of fine migration to the water relative permeability, the effect of swelling clay on water relative permeability is more severe. It is because the swelling clays will expand upon the hydration or when in contact with fresh water, thus this will reduce the pore volume and decrease the permeability. The graph for the relationship between relative permeability and water saturation and effect of clay swelling is shown in Figure 4.8.

During clay swelling, high absorption of water can be associated with smaller mobility ratio of water adjacent to mineral surface. Hence, the relative permeability of water in that area will be reduced. In addition, pseudo immobile water content separates zones of greater water relative permeability value from others presenting a restricted flow. This phenomenon leads to consistent with intra/intercluster water content with aggregation of clay particles. In addition, the reduction in water relative permeability drops substantially even though maximum water saturation is high due to reduction in residual oil saturation by in viscosity reduction effects.

Company _____ Formation _____
Well _____ Country _____
Field _____

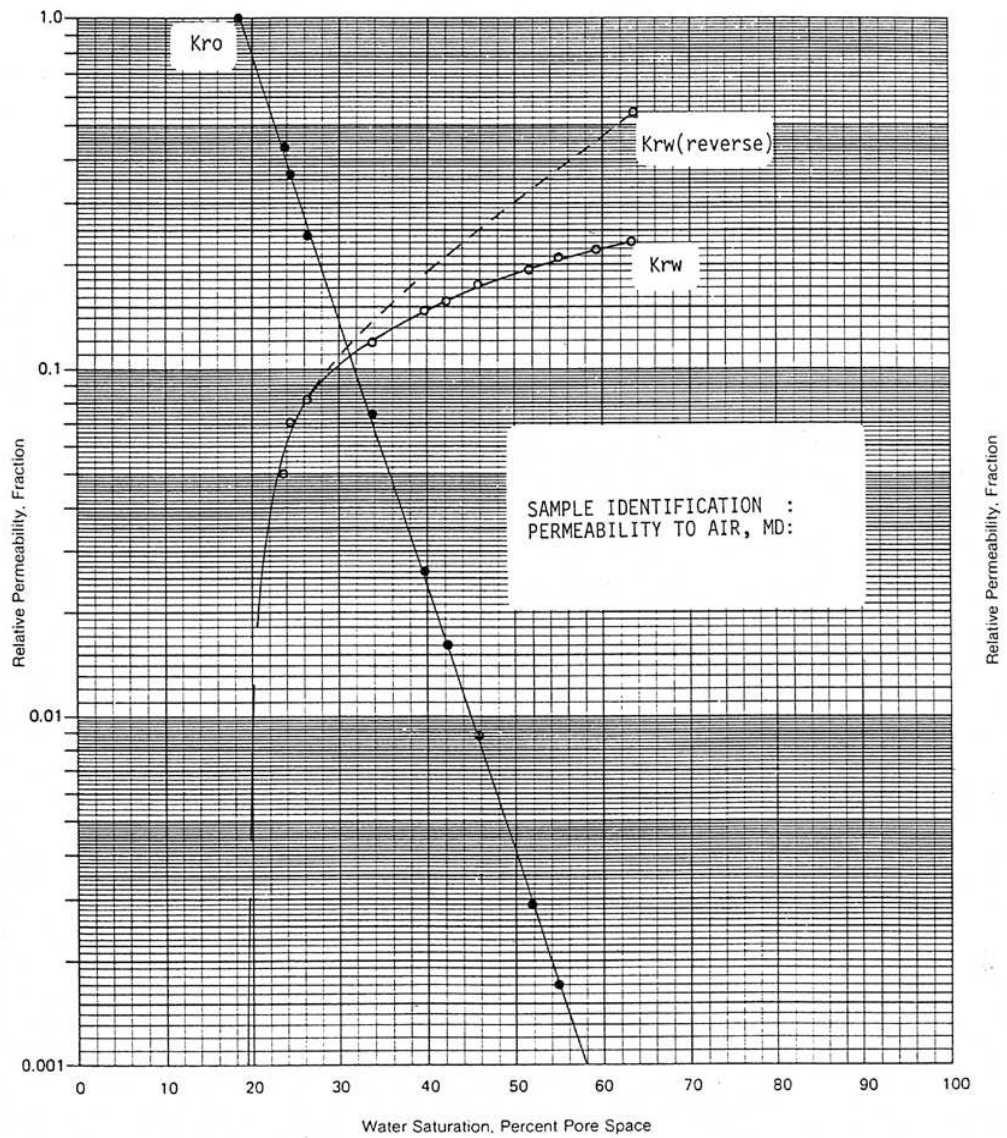


Figure 4.7: Effect of Fine Migration on Relative Permeability (PCSB, n.d.)

Company _____ Formation _____
Well _____ Country _____
Field _____

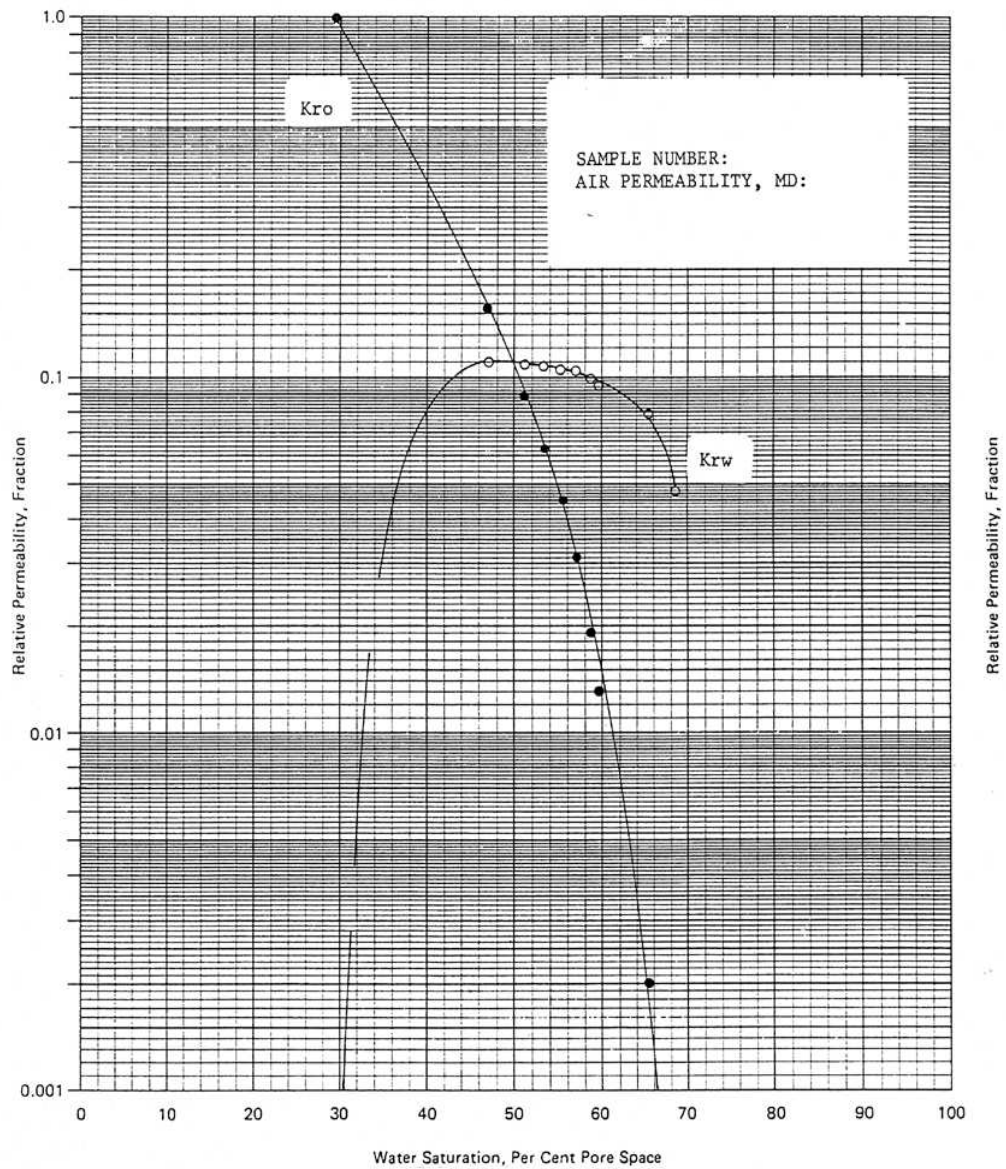


Figure 4.8: Effect of Clay Swelling on Relative Permeability (PCSB, n.d.)

4.3.2 Effect of Clay Minerals on Water Saturation

In this section, water saturations are calculated based on three different approaches which are using Waxman-Smits-Thomas, laboratory data and Archie equation. In Waxman-Smits-Thomas, water saturation calculation is based on the corrected laboratory data adjusted with CEC of clay minerals. Meanwhile the values for Archie equation are based on the practical value that usually used for the clean sand. Based on the data taken from the laboratory work, the value of constant value (a), cementation factor (m) and saturation exponent (n) are shown in Table 4.2.

Table 4.2: Value of Variable used for Saturation Calculation (PCSB, n.d.)

Variables	Waxman-Smits-Thomas (corrected)	Laboratory Data	Archie Equation (Clean Sand)
Constant Value (a)	1.0	1.0	1.0
Cementation factor (m)	m* 1.92	1.63	2.0
Saturation exponent (n)	n* 2.87	2.38	2.0

Table 4.3 shows the result of water saturation calculation based on same formation porosity with the manipulation of the value of a, m and n shown in Table 12. Based on the result in Table 13, water saturation calculation based on Archie equation are excess/higher compare to other two methods. This can give the indication that the used of Archie equation that is used for clean sand will give extra value for water saturation as it cannot differentiate between water saturation from the pore system and water saturation due to the existence of clay minerals in the formation. It is because the presence of clay minerals in the formation will give extra water conductivity as it is due to the clay bound water at the surface of formation.

Hence, the laboratory data have been conducted in order to investigate the values for a, n and m based on the core samples. However, this method is still inaccurate as it is not taking account the presence of clay in the formation. The used of laboratory data without the correction to the clay content will give overestimate value of water

saturation. Therefore, the Waxman-Smits-Thomas has been introduced as it can compensate with the excess water due to clay bound water. It is because in this method, the value has been corrected to the value based on CEC of the clay minerals. The calculation of water saturation based on respective CEC of the clay minerals is more accurate and feasible to be used for water saturation calculation.

Table 4.3: The Result of Water Saturation Calculation (PCSB, n.d.)

No	Porosity	Waxman-Smits-Thomas	Laboratory Data	Archie Equation (Clean Sand)
		Sw:%PV		
1	20.4	47	55	66
2	17.8	56	68	87
3	16.3	57	72	95
4	20.1	54	64	79
5	14.3	61	80	111
6	25.2	59	59	69
7	25.4	55	51	58
8	27.3	57	52	57
9	17.5	74	73	95
10	20.0	60	70	88
11	17.4	68	75	99
12	14.4	74	86	119

The exact value of a, n and m to be used in water saturation calculation is very important as it will give the accurate value of water saturation especially in the shaly formation with present of clay minerals. The accuracy on water saturation calculation is important as it will give the indication of saturation of oil, hence the stock tank oil-in-place STOOIP of reservoir.

4.3.3 Effect of Clay Minerals Distribution on Capillary Pressure

The effect of clay minerals distribution on capillary pressure is shown in Figure 25. From the thin section analysis based on Figure 4.9(a), the grain size distribution is based on bimodal distribution behaviour. It shows by the main types of grain size (pore throat) in the formation; one with larger flow capacity than other. This can give an indication that the formation has the difference permeability based on the grain sorting, size and clay matrix.

Based on the result, the upper part of the thin section has the higher permeability which is 218 mD compared to lower part of the thin section, which is at only 19 mD. This is due to the greater or coarser grain size at the upper side of the thin section compare to lower part of the thin section. Greater or coarser grain size will leave the bigger pores between the grains. Comparing to the lower or small grain size, the smaller grain size will fill the void between the particles. In addition, the changes of pore geometry under the thin section can also indicate the high heterogeneity reservoir rock.

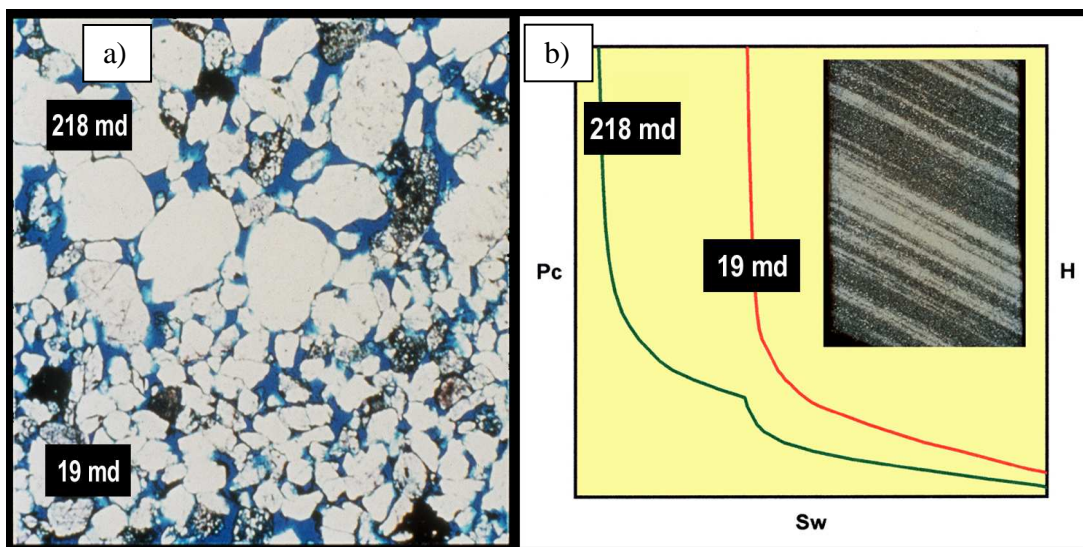


Figure 4.9: Clay Minerals Distribution a) Thin Section and b) Capillary Pressure Curve Relationship (PCSB, n.d.)

In addition, Figure 4.9(b) shows capillary pressure versus water saturation relationship. The figure shows two types of capillary curves which indicate two types of permeability in the formation. The graph of capillary pressure is shift upward to the right indicates that the red graph is the poorer permeability compared to green line. It also shows that the increase in irreducible water saturation. In addition, the discontinuity of lower capillary curve is caused by bimodal distribution. It can be related to the right area of the thin section that towards lower part of thin section it is the decrease in reservoir quality due to smaller grain size. Moreover, the higher capillary pressure is shown in lower permeability zone. It is due to the higher capillary pressure is needed in order to invade the fluid into the smaller pores and pore throats.

4.3.4 Effects of Clay Mineralogy on Log Response

In this section, the effects of lithology and mineralogy on log response are based on mineral composition of clays and silts as a constituent in the shaly formation are investigated. The effect on gamma ray, resistivity and density logs will be discussed in details. Table 4.4 show the types of lithology and minerals that can affect the log responses.

Table 4.4: Effect of Lithology/Mineralogy on Logs Response (PCSB, n.d.)

Lithology/Mineralogy	Logging Tools	Effect
Common, variable potassium feldspar	Gamma Ray	<ul style="list-style-type: none"> • Increase response for clean sandstone • Inaccurate V_{shale} • Problem in comparing two cored sands
Pore-filling kaolinite	Gamma Ray	<ul style="list-style-type: none"> • Kaolinite not detected • Slight under-estimation V_{shale}
Laminar and structural clay	<ul style="list-style-type: none"> • Resistivity • Gamma Ray 	<ul style="list-style-type: none"> • Undistinguishable from dispersed clay on logs • Under-estimation of porosity and permeability
Siderite	Density	<ul style="list-style-type: none"> • Higher grain density • Under-estimation of total porosity
Glaucony, other structural clays	<ul style="list-style-type: none"> • Resistivity • Gamma Ray 	<ul style="list-style-type: none"> • Increase in gamma response • Decrease in net matrix resistivity • Neutron porosity could be over-optimistic

The presence of common and variable potassium feldspar (k-feldspar) in the formation will give the huge effect on gamma ray log response. In principle gamma ray will give reading on naturally occur gamma ray radiation in the formation. However, this measurement can be inaccurate with presence of other radioactive minerals such as k-feldspar in the clean sandstone, as it will give an overestimated value of gamma ray. Hence, this will affect the volume of shale calculation. Thus, in the presence of k-feldspar in formation, the used of spectral log is more feasible as it can breaks natural radioactive reading of a formation into different types of radioactive material; thorium, potassium and uranium. In addition, the problem will also occurs when comparing two cored sands based on gamma ray response. It is because the core data will give difference values from the log readings.

Moreover, pore-filling by kaolinite clay can also affect the gamma ray log response. Kaolinite is more likely to be migrated as fine particle in the formation hence; cementing the pore spaces or acts as pore filling. In general, kaolinite has a low gamma ray response compare to other clay minerals. Therefore, the sands with the pore-filling of kaolinite will give a lower value of gamma rays, thus will give slightly underestimated volume of shale as the cemented kaolinite is not detected by the gamma ray response as a clay minerals.

Next are the effects of laminar and structural clays on resistivity and gamma ray logs, in which these distributions of clay minerals cannot be distinguished from dispersed clay on logs. As previously investigated, the types of clay minerals distribution plays important roles in calculating total porosity hence total volume of shale in formation. Dispersed clay minerals are more severe to the porosity and permeability of formation as its coating and filling intergranular space of grains. Hence, undistinguishable dispersed clay in formation can leads to underestimation of porosity and permeability of reservoir rock.

In addition, the presence of siderite can also affect the log response. Siderite mineral commonly occurs in thin beds with shales; hence its effect on log response is important.

Generally, siderite has higher than normal grain density; hence it can give under estimation of total porosity.

Furthermore, glaucony (granular mineral of mica group) and other structural clay minerals can give the effect on resistivity and gamma ray log. The presence of clay minerals gives increase in gamma ray response. However, with presence of clay bound water at the surface of clay minerals the net matrix of resistivity is decrease and give over-optimistic value on neutron porosity due to high value of hydrogen atom in clay bound water.

4.4 Potential Formation Damage from Diagenetic Components

The effect of fine migration and swelling of clay minerals in formation can lead to the formation damage especially near wellbore area. This phenomenon leads to permeability impairment hence the productivity of hydrocarbon in reservoir. Since there are wide ranges of the potential problems due to formation damage, hence this section is mainly discussed on the problem of formation damage associated with type of clay minerals and also its treatment as shown in Table 4.5. The formation damage will be discussed based on magnitude of potential problem with maximum magnitude of 3 and minimum magnitude of 1.

The most sensitive mineral is smectite as it has high cation exchange capacity and it tends to swell with the presence of fresh water. Hence, the formation contains high smectite group minerals should be avoided from using the fresh water. According to Hensen and Smit (2002), it is more feasible to use potassium chloride (KCl) solutions as shale swelling inhibitors in drilling fluids. It is due to the fact that potassium ion (K^+)-containing clays show lower tendency to swell compare to sodium ion (Na^+), as it has very weak interaction with water. However, if the formation damage has occurs, the used of acid stimulation (hydrochloric (HCL) and hydrofluoric (HF) acids) is needed with the correct pre- and post-flushes as to prevent the water blockage and improve flowback performance after the stimulation job.

Table 4.5: Potential of Formation Damage and Its Treatment (PCSB, n.d.)

Magnitude of Potential Problem	Sensitive Mineral	Potential Problem	Avoid Using	Use	Treatment
3	Smectite	Swelling	Fresh water systems	KCl of hydrocarbon systems	Acidise with HCl/HF and use correct pre and post-flushes
2	Siderite	Iron Hydroxide precipitate	Oxygen-rich systems,	Acid systems, oxygen scavengers	
2	Chlorite		Oxygen-rich systems, high pH		
2	Pyrite		Iron Hydroxide precipitate, sulphate production		
1	Kaolinite	Fines migration,	High flow rates, high transient pressures	Low flow rates, low transient pressures	Use a clay stabiliser
1	Illite	Fines migration, microporosity “mushing”	High flow rates, fresh water systems	Low flow rates, KCl or hydrocarbon systems	Acidise with HCl/HF and use correct pre and post-flushes

Next, the second highest magnitudes of sensitive minerals are siderite, chlorite and pyrite. These minerals lead to iron hydroxide precipitation with the presence of oxygen-rich system. Hence, the used of oxygen scavengers in order to lower the dissolved oxygen content in solution is needed. In addition, as these minerals can lead to iron precipitation, the use of acid system can prevent formation damage. Otherwise, the stimulation work as per discussion above and the chelating agents need to be used in order to eliminate the formation damage issue. The use of chelating agent is to control

the reaction between metal ions or to prevent precipitation of solids during acid stimulation. Comparing between siderite, chlorite and pyrite; chlorite can also lead to iron hydroxide precipitation when there is high pH conditions, meanwhile, pyrite (iron sulphate- FeS_2) can react with Ca^{+2} , Sr^{+2} and Ba^{+2} metal ions to form iron hydroxide precipitation.

Moreover, kaolinite and illite groups can also lead to formation damage even though the magnitude of formation damage is low. As per discussion in clay minerals identification, kaolinite and illite can lead to fine migration problem due to their structure and the bonding between clay and grain surface. The problem with fine migration is happened when there is high flow rates used during hydrocarbon production; hence the use of low production flowrate is more feasible with the presence of these types of clay minerals. For the case of kaolinite, the high transient pressure can lead to additional reason for fine migration as its platelets and stacks structure are easily broke. Hence, low transient pressure and use of clay stabiliser is needed for the kaolinite group in order to retain the clay platelets location by controlling the charge of treatment fluid. Meanwhile, illite group has an ability to “mush” the microporosity of the formation when there is a presence of fresh water. Since, illite is sensitive to fresh water, the use of potassium chloride (KCl) solutions is more feasible as per discussion above adds with the acid stimulation using hydrochloric (HCL) and hydrofluoric (HF) acids with the correct pre- and post-flushes.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

The presence of clay minerals in reservoir has a great impact on reservoir characterization and performance. The inaccuracy in formation evaluation in terms of porosity and water saturation can affect the determination of reservoir volume and hydrocarbon-in-place. In addition, the effect of clay minerals on logs response needs to be corrected by using various types of models and methods in order to obtain accurate value of porosity, water saturation and permeability. Moreover, the effects of clay minerals on reservoir performance are due to fine migration and swelling of clay during drilling, water injection and acid stimulation. This phenomenon leads to permeability impairment due to formation damage near wellbore area. The reduction in permeability will affect the productivity of the reservoir.

Volume of shale is one of the important criteria in reservoir characterization as it needs to be corrected at the later stage. Hence, the effects of clay minerals in log interpretation based on gamma ray, neutron-density and resistivity logs are investigated. Based on calculated volume of shale in the log interpretation, natural gamma ray log gives overestimated volume of shale compared to calculation using neutron-density and resistivity logs.

Furthermore, various integrated analysis on clay minerals characteristics used in this project show better understanding on clay minerals morphology, structure and occurrence. Based on the analysis of the effect of clay minerals on the reservoir, it is shown that there are reduction in water relative permeability due to fine migration and swelling of clays. In addition, more accurate value of water saturation can be obtained by using Waxman-Smit-Thomas model. In the analysis of capillary pressure curve, there is a reflection of capillary pressure curve due to heterogeneity and bimodality of the

reservoir. Next by examine the potential problem of formation damage, its mitigation plan and treatment has been introduced.

5.2 Recommendations

Based on the study in this project, there are some recommendations have been suggested in order to improve and obtain the better results in future research:

i. Using Nuclear Magnetic Resonance (NMR) to calculate clay bound water and capillary water due to presence of clays and fine grains.

Since in this report the calculation of volume of clay is based on conventional logging tools such as gamma ray, neutron-density and resistivity, the used of NMR can give better indication of clays volume. It is because NMR can compute clay-bound-water and capillary water directly from the log. The used of NMR can give accurate data as it can differentiate between free water, clay-bound-water and capillary water. Free water is the main interest in formation evaluation as it has flow capability comparing to clay-bound-water that is due to the clay minerals and capillary water which are immobile. Hence, the underestimate value of resistivity can be prevented. In addition, the identification of clay-bound-water from NMR can be used to correct the calculation of porosity and water saturation due to clay minerals. According to Mohammadlou and Mork (2012), the types of clay minerals can be identified based on different relaxation time (T2) cut off values of NMR at shorter times decay. In addition this method is more accurate compare to other method of calculating clay volume as other methods such as gamma ray is depending on the chosen values from clean and shaly rock samples; hence this will give different result for different method of calculation.

- ii. Recommend to know in front the clay mineral composition before stimulation and water injection in order to avoid any damage due to sensitivity of clay minerals to acids and water.**

Acid stimulation treatment is used to improve permeability of formation by removing formation damage near wellbore area. However, the used of incompatible acids into the formation can leads to severe impact on reservoir permeability. Hence, it is recommended to do the critical study on types of clay minerals composition before conducting any acid stimulation job. In practice, hydrochloric (HCl) and hydrofluoric (HF) are the common acids used in stimulation job. However, the reaction between HCl acid and iron minerals can leads to the gelatinous ferric hydroxide. Meanwhile, the reaction of HF acid with calcium bearing and silicate minerals can leads to the inorganic scaling. Both of these phenomena can block the pore throat and reduce the permeability of the formation. Moreover, incorrect volume and concentration of acids can also damage the area near wellbore. In addition, incompatible between clay minerals and water injection can also reduce the permeability due to fines migration and swelling properties of clay minerals. Hence, it is important to know in advance types of clay minerals because implementing acid stimulation and water injection.

- iii. Integrated studies on shaly or thin bed reservoir.**

It is recommended to use the integrated studies on shaly sand or thin bed reservoir in order to obtained accurate formation evaluation. The presence of clays in shaly reservoir leads to various inaccuracy in formation evaluation in terms of porosity, water saturation and permeability of reservoir. Various integrated studies based on combination of conventional logging tools, cross-plotting and some modelling need to be used and investigated into details. The used of conventional logging tools in evaluating reservoir leads to the underestimated value of hydrocarbon volume. In addition, direct log interpretations will oversight the evaluation of thin bed sand as the log has low vertical resolutions and it can only characterize on

average of multiple beds. Eshimokhai *et al.* (2012) have introduced the methods for better thin beds characterisation by using resistivity borehole imaging and NMR technique. In this technique, the core data are correlated with borehole images in order to confirm the presence of thin bed. In addition, the introduction of Thomas- Stieber equations using laminated sand-shale sequence also has been used in evaluation reservoir porosity, hydrocarbon saturation and shale volume.

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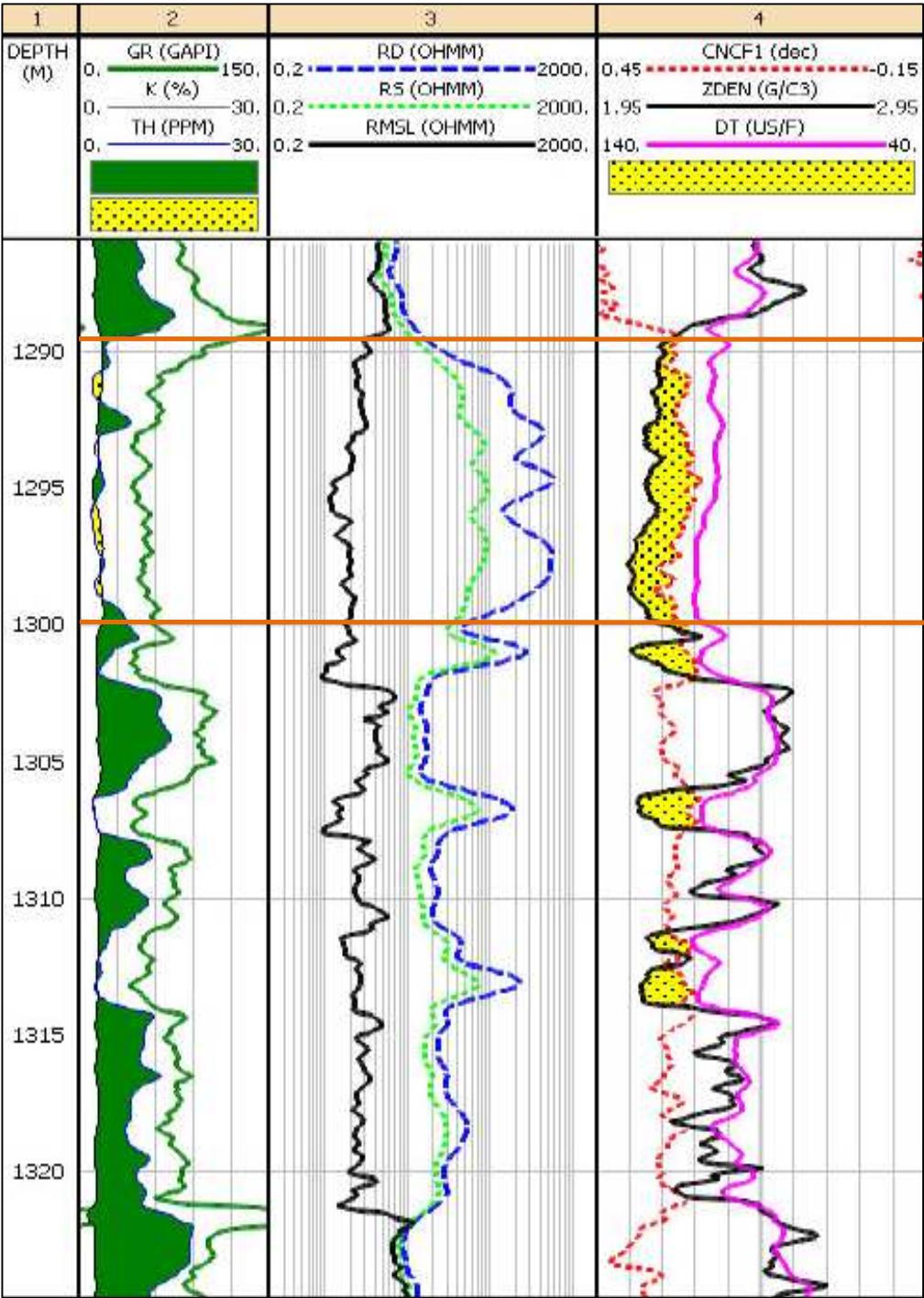
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APPENDIX A: Logs Response (Gamma Ray, SGR, Resistivity, Neutron and Density Logging Tools)



A

Figure A- 1: Logs Response for Shaly Reservoir (Hussein and Ahmed, 2012)

APPENDIX B: Calculation of Volume of Shale from Gamma Ray Log

No.	TVD (m)	GR (API)	GR - GRmin	GRmax - GRmin	Vshale
1	1286.08	80.50	34.50	69	0.50
2	1286.64	89.70	43.70	69	0.63
3	1287.20	92.00	46.00	69	0.67
4	1287.76	97.75	51.75	69	0.75
5	1288.32	115.00	69.00	69	1.00
6	1288.88	150.00	104.00	69	1.51
7	1289.44	115.00	69.00	69	1.00
8	1290.00	97.75	51.75	69	0.75
9	1290.56	59.80	13.80	69	0.20
10	1291.12	57.50	11.50	69	0.17
11	1291.68	59.80	13.80	69	0.20
12	1292.24	59.80	13.80	69	0.20
13	1292.80	46.00	0.00	69	0.00
14	1293.36	46.00	0.00	69	0.00
15	1293.92	66.70	20.70	69	0.30
16	1294.48	48.30	2.30	69	0.03
17	1295.04	46.00	0.00	69	0.00
18	1295.60	46.00	0.00	69	0.00
19	1296.16	56.35	10.35	69	0.15
20	1296.72	48.30	2.30	69	0.03
21	1297.28	57.50	11.50	69	0.17
22	1297.84	48.30	2.30	69	0.03
23	1298.40	47.15	1.15	69	0.02
24	1298.96	48.30	2.30	69	0.03
25	1299.52	57.50	11.50	69	0.17
26	1300.08	49.45	3.45	69	0.05
27	1300.64	80.50	34.50	69	0.50
28	1301.20	46.00	0.00	69	0.00
29	1301.76	47.15	1.15	69	0.02
30	1302.32	57.50	11.50	69	0.17
31	1302.88	103.50	57.50	69	0.83
32	1303.44	115.00	69.00	69	1.00
33	1304.00	103.50	57.50	69	0.83
34	1304.56	103.50	57.50	69	0.83
35	1305.12	103.50	57.50	69	0.83
36	1305.68	101.20	55.20	69	0.80
37	1306.24	80.50	34.50	69	0.50

No.	TVD (m)	GR (API)	GR - GRmin	GRmax - GRmin	Vshale
38	1306.80	46.00	0.00	69	0.00
39	1307.36	46.00	0.00	69	0.00
40	1307.92	47.15	1.15	69	0.02
42	1309.04	92.00	46.00	69	0.67
43	1309.60	80.50	34.50	69	0.50
44	1310.16	82.80	36.80	69	0.53
45	1310.72	85.10	39.10	69	0.57
46	1311.28	82.80	36.80	69	0.53
47	1311.84	57.50	11.50	69	0.17
48	1312.40	46.00	0.00	69	0.00
49	1312.96	57.50	11.50	69	0.17
50	1313.52	56.35	10.35	69	0.15
51	1314.08	46.00	0.00	69	0.00
52	1314.64	55.20	9.20	69	0.13
53	1315.20	88.55	42.55	69	0.62
54	1315.76	69.00	23.00	69	0.33
55	1316.32	69.00	23.00	69	0.33
56	1316.88	71.30	25.30	69	0.37
57	1317.44	90.84	44.84	69	0.65
58	1318.00	74.75	28.75	69	0.42
59	1318.56	74.75	28.75	69	0.42
60	1319.12	69.00	23.00	69	0.33
61	1319.68	69.00	23.00	69	0.33
62	1320.24	80.50	34.50	69	0.50
63	1320.80	90.85	44.85	69	0.65
64	1321.36	80.50	34.50	69	0.50
65	1321.92	69.00	23.00	69	0.33
66	1322.48	150.00	104.00	69	1.51
67	1323.04	150.00	104.00	69	1.51
68	1323.60	103.50	57.50	69	0.83
69	1324.16	113.85	67.85	69	0.98
70	1324.72	103.50	57.50	69	0.83
71	1325.28	92.00	46.00	69	0.67
72	1325.84	103.50	57.50	69	0.83

APPENDIX C: SGR Log Reading

No.	TVD (m)	K (%)	TH (ppm)	TH/K
1	1286.08	2.31	9.24	4.00
2	1286.64	2.77	9.24	3.34
3	1287.20	2.31	9.24	4.00
4	1287.76	2.31	11.55	5.00
5	1288.32	2.31	16.17	7.00
6	1288.88	2.77	13.86	5.00
7	1289.44	4.16	4.16	1.00
8	1290.00	4.16	4.16	1.00
9	1290.56	4.16	1.16	0.28
10	1291.12	4.16	1.16	0.28
11	1291.68	2.08	2.31	1.11
12	1292.24	2.77	4.85	1.75
13	1292.80	2.13	4.62	2.17
14	1293.36	2.77	1.16	0.42
15	1293.92	2.77	2.31	0.83
16	1294.48	2.13	4.16	1.95
17	1295.04	2.13	4.39	2.06
18	1295.60	2.13	2.54	1.19
19	1296.16	4.62	1.16	0.25
20	1296.72	4.85	1.16	0.24
21	1297.28	4.85	4.62	0.95
22	1297.84	5.08	4.85	0.95
23	1298.40	2.13	2.13	1.00
24	1298.96	4.85	1.85	0.38
25	1299.52	4.85	5.31	1.09
26	1300.08	4.62	6.93	1.50
27	1300.64	2.54	9.24	3.64
28	1301.20	2.54	5.31	2.09
29	1301.76	2.54	2.64	1.04
30	1302.32	2.54	5.08	2.00
31	1302.88	2.54	12.01	4.73
32	1303.44	2.54	12.01	4.73
33	1304.00	3.00	13.86	4.62
34	1304.56	2.54	15.71	6.19
35	1305.12	3.00	13.40	4.47
36	1305.68	3.47	9.24	2.66
37	1306.24	2.54	7.39	2.91

No.	TVD (m)	K (%)	TH (ppm)	TH/K
38	1306.80	2.13	2.13	1.00
39	1307.36	2.13	2.13	1.00
40	1307.92	2.13	2.13	1.00
41	1308.48	3.47	9.24	2.66
42	1309.04	2.77	11.55	4.17
43	1309.60	2.77	8.09	2.92
44	1310.16	2.77	8.09	2.92
45	1310.72	2.13	11.32	5.31
46	1311.28	3.23	11.09	3.43
47	1311.84	3.00	4.39	1.46
48	1312.40	3.00	4.62	1.54
49	1312.96	3.00	3.00	1.00
50	1313.52	3.00	3.00	1.00
51	1314.08	3.00	3.00	1.00
52	1314.64	3.00	3.47	1.16
53	1315.20	3.00	11.55	3.85
54	1315.76	3.00	11.32	3.77
55	1316.32	3.00	11.32	3.77
56	1316.88	3.00	9.24	4.24
57	1317.44	3.00	12.71	3.05
58	1318.00	3.23	9.14	2.50
59	1318.56	3.23	8.09	2.50
60	1319.12	3.23	8.09	2.15
61	1319.68	2.13	6.93	4.34
62	1320.24	2.13	9.24	4.43
63	1320.80	2.13	9.44	4.29
64	1321.36	2.13	9.14	4.38
65	1321.92	2.13	9.34	4.34
66	1322.48	1.16	9.24	15.93
67	1323.04	2.08	18.48	8.79
68	1323.60	2.13	18.28	8.58
69	1324.16	2.13	18.28	8.58
70	1324.72	2.13	18.28	6.51
71	1325.28	2.13	13.86	5.42
72	1325.84	2.13	11.55	0.00

APPENDIX D: Determination of Types of Clay Minerals from SGR

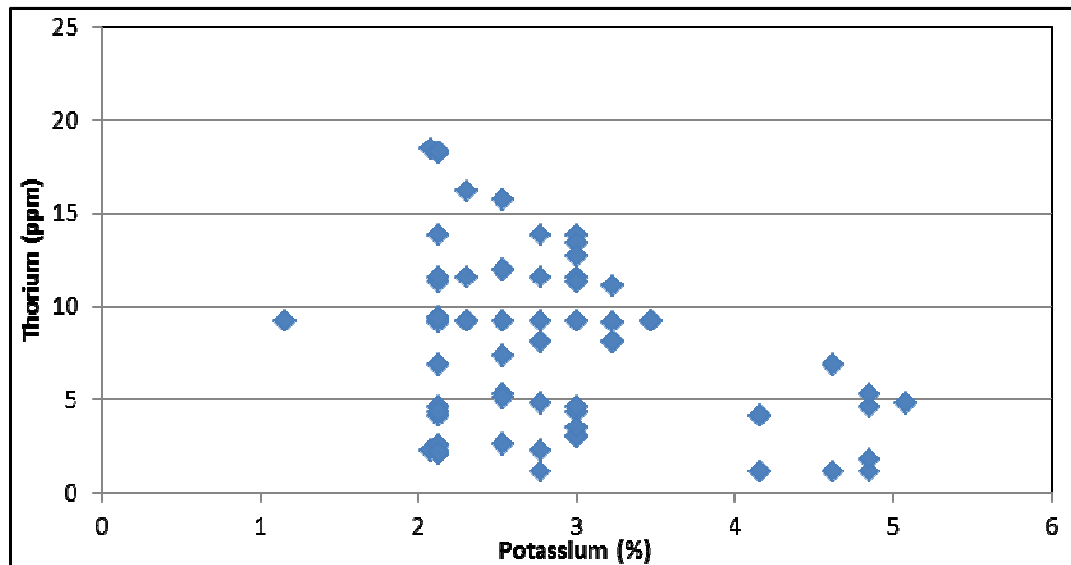


Figure D-1: Thorium and Potassium Relationship from SGR Reading

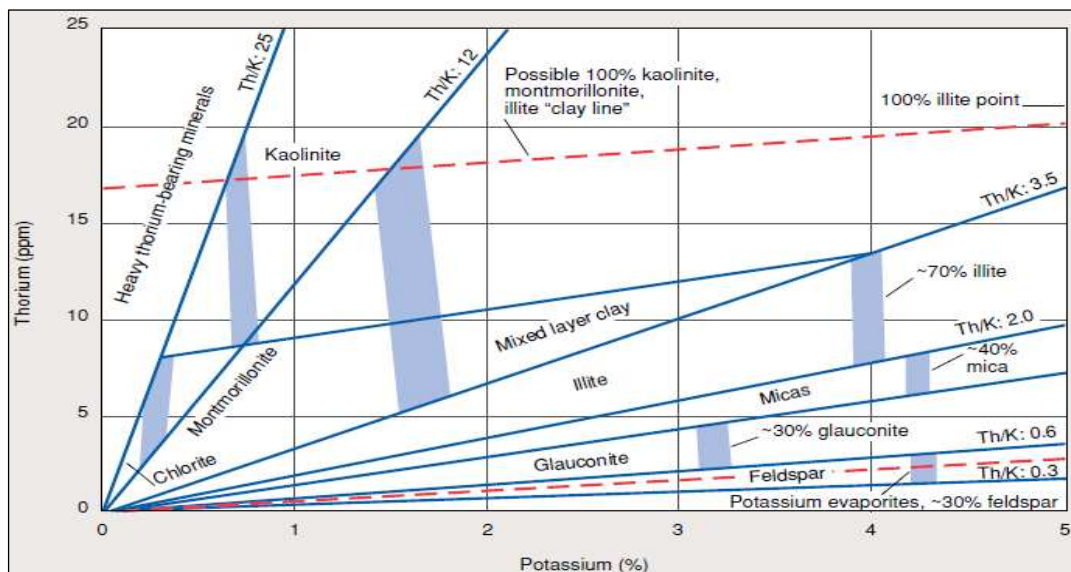


Figure D-2: Types of Clay Identification Based on Thorium Potassium Relationship (Formation Evaluation Manual)

APPENDIX E: Neutron-Density Log Reading

a) Density Log Reading

No	TVD (m)	Density (g/c3)	$\rho_{ma}-\rho_b$	$\rho_{ma}-\rho_f$	Porosity, Φ
1	1286.08	2.45	0.2000	1.75	0.1143
2	1286.64	2.44	0.2100	1.75	0.1200
3	1287.20	2.55	0.1000	1.75	0.0571
4	1287.76	2.55	0.1000	1.75	0.0571
5	1288.32	2.45	0.2000	1.75	0.1143
6	1288.88	2.25	0.4000	1.75	0.2286
7	1289.44	2.17	0.4800	1.75	0.2743
8	1290.00	2.14	0.5100	1.75	0.2914
9	1290.56	2.14	0.5100	1.75	0.2914
10	1291.12	2.13	0.5200	1.75	0.2971
11	1291.68	2.15	0.5000	1.75	0.2857
12	1292.24	2.13	0.5200	1.75	0.2971
13	1292.80	2.1	0.5500	1.75	0.3143
14	1293.36	2.1	0.5500	1.75	0.3143
15	1293.92	2.15	0.5000	1.75	0.2857
16	1294.48	2.1	0.5500	1.75	0.3143
17	1295.04	2.1	0.5500	1.75	0.3143
18	1295.60	2.15	0.5000	1.75	0.2857
19	1296.16	2.1	0.5500	1.75	0.3143
20	1296.72	2.07	0.5800	1.75	0.3314
21	1297.28	2.07	0.5800	1.75	0.3314
22	1297.84	2.04	0.6100	1.75	0.3486
23	1298.40	2.07	0.5800	1.75	0.3314
24	1298.96	2.05	0.6000	1.75	0.3429
25	1299.52	2.1	0.5500	1.75	0.3143
26	1300.08	2.11	0.5400	1.75	0.3086
27	1300.64	2.27	0.3800	1.75	0.2171
28	1301.20	2.05	0.6000	1.75	0.3429
29	1301.76	2.15	0.5000	1.75	0.2857
30	1302.32	2.35	0.3000	1.75	0.1714
31	1302.88	2.53	0.1200	1.75	0.0686
32	1303.44	2.45	0.2000	1.75	0.1143
33	1304.00	2.54	0.1100	1.75	0.0629
34	1304.56	2.5	0.1500	1.75	0.0857

No	TVD (m)	Density (g/c3)	$\rho_{ma}-\rho_b$	$\rho_{ma}-\rho_f$	Porosity, Φ
35	1305.12	2.5	0.1500	1.75	0.0857
36	1305.68	2.43	0.2200	1.75	0.1257
37	1306.24	2.35	0.3000	1.75	0.1714
38	1306.80	2.07	0.5800	1.75	0.3314
39	1307.36	2.07	0.5800	1.75	0.3314
40	1307.92	2.27	0.3800	1.75	0.2171
41	1308.48	2.45	0.2000	1.75	0.1143
42	1309.04	2.45	0.2000	1.75	0.1143
43	1309.60	2.35	0.3000	1.75	0.1714
44	1310.16	2.25	0.4000	1.75	0.2286
45	1310.72	2.45	0.2000	1.75	0.1143
46	1311.28	2.45	0.2000	1.75	0.1143
47	1311.84	2.15	0.5000	1.75	0.2857
48	1312.40	2.1	0.5500	1.75	0.3143
49	1312.96	2.25	0.4000	1.75	0.2286
50	1313.52	2.1	0.5500	1.75	0.3143
51	1314.08	2.08	0.5700	1.75	0.3257
52	1314.64	2.08	0.5700	1.75	0.3257
53	1315.20	2.45	0.2000	1.75	0.1143
54	1315.76	2.35	0.3000	1.75	0.1714
55	1316.32	2.3	0.3500	1.75	0.2000
56	1316.88	2.35	0.3000	1.75	0.1714
57	1317.44	2.4	0.2500	1.75	0.1429
58	1318.00	2.3	0.3500	1.75	0.2000
59	1318.56	2.35	0.3000	1.75	0.1714
60	1319.12	2.17	0.4800	1.75	0.2743
61	1319.68	2.33	0.3200	1.75	0.1829
62	1320.24	2.31	0.3400	1.75	0.1943
63	1320.80	2.35	0.3000	1.75	0.1714
64	1321.36	2.25	0.4000	1.75	0.2286
65	1321.92	2.18	0.4700	1.75	0.2686
66	1322.48	2.55	0.1000	1.75	0.0571
67	1323.04	2.53	0.1200	1.75	0.0686
68	1323.60	2.63	0.0200	1.75	0.0114
69	1324.16	2.48	0.1700	1.75	0.0971
70	1324.72	2.46	0.1900	1.75	0.1086
71	1325.28	2.6	0.0500	1.75	0.0286
72	1325.84	2.5	0.1500	1.75	0.0857

b) Neutron Log Reading

No.	TVD (m)	NPHI (dec)
1	1286.08	0.438
2	1286.64	0.438
3	1287.20	0.420
4	1287.76	0.408
5	1288.32	0.450
6	1288.88	0.330
7	1289.44	0.282
8	1290.00	0.300
9	1290.56	0.276
10	1291.12	0.276
11	1291.68	0.300
12	1292.24	0.300
13	1292.80	0.282
14	1293.36	0.276
15	1293.92	0.270
16	1294.48	0.258
17	1295.04	0.270
18	1295.60	0.270
19	1296.16	0.282
20	1296.72	0.288
21	1297.28	0.288
22	1297.84	0.312
23	1298.40	0.312
24	1298.96	0.330
25	1299.52	0.312
26	1300.08	0.276
27	1300.64	0.282
28	1301.20	0.282
29	1301.76	0.318
30	1302.32	0.270
31	1302.88	0.330
32	1303.44	0.330
33	1304.00	0.306
34	1304.56	0.330
35	1305.12	0.330
36	1305.68	0.300

No.	TVD (m)	NPHI (dec)
37	1306.24	0.282
38	1306.80	0.270
39	1307.36	0.276
40	1307.92	0.270
41	1308.48	0.312
42	1309.04	0.312
43	1309.60	0.318
44	1310.16	0.324
45	1310.72	0.324
46	1311.28	0.318
47	1311.84	0.330
48	1312.40	0.270
49	1312.96	0.282
50	1313.52	0.288
51	1314.08	0.276
52	1314.64	0.282
53	1315.20	0.270
54	1315.76	0.330
55	1316.32	0.324
56	1316.88	0.318
57	1317.44	0.330
58	1318.00	0.342
59	1318.56	0.288
60	1319.12	0.312
61	1319.68	0.282
62	1320.24	0.330
63	1320.80	0.336
64	1321.36	0.330
65	1321.92	0.306
66	1322.48	0.330
67	1323.04	0.360
68	1323.60	0.378
69	1324.16	0.396
70	1324.72	0.420
71	1325.28	0.342
72	1325.84	0.360

APPENDIX F: Resistivity Log Reading

No.	TVD (m)	Res Deep (ohm)	Res MSL (ohm)	Res Shallow (ohm)
1	1286.08	16	8	8
2	1286.64	12	8	8
3	1287.20	16	6	10
4	1287.76	20	10	12
5	1288.32	22	10	14
6	1288.88	24	14	16
7	1289.44	40	6	34
8	1290.00	60	6	40
9	1290.56	200	4	60
10	1291.12	400	3	100
11	1291.68	380	4	100
12	1292.24	400	6	80
13	1292.80	1000	4	180
14	1293.36	600	3.8	200
15	1293.92	400	4	120
16	1294.48	1400	3.8	200
17	1295.04	800	3	200
18	1295.60	300	2.2	160
19	1296.16	400	4	100
20	1296.72	800	3	200
21	1297.28	1200	4	200
22	1297.84	1200	4	190
23	1298.40	1000	4	140
24	1298.96	700	4	80
25	1299.52	300	4	100
26	1300.08	100	3.8	60
27	1300.64	80	5	60
28	1301.20	600	3	220
29	1301.76	200	2.2	80
30	1302.32	40	3	26
31	1302.88	38	18	25
32	1303.44	30	10	20
33	1304.00	38	8	30
34	1304.56	34	8	28
35	1305.12	34	8	30
36	1305.68	30	6	20
37	1306.24	60	6	40

No.	TVD (m)	Res Deep (ohm)	Res MSL (ohm)	Res Shallow (ohm)
38	1306.80	300	3	100
39	1307.36	400	3.6	180
40	1307.92	100	2.2	40
41	1308.48	50	7	36
42	1309.04	36	6	36
43	1309.60	38	4	22
44	1310.16	42	5	30
45	1310.72	40	5	28
46	1311.28	40	12	38
47	1311.84	60	6	38
48	1312.40	90	3.9	60
49	1312.96	80	4	60
50	1313.52	380	6	100
51	1314.08	400	6	120
52	1314.64	100	4	40
53	1315.20	60	8	40
54	1315.76	50	6	40
55	1316.32	40	5	36
56	1316.88	50	4.4	36
57	1317.44	60	6	38
58	1318.00	60	4.2	38
59	1318.56	80	4.2	40
60	1319.12	120	5	60
61	1319.68	120	4	60
62	1320.24	80	4	38
63	1320.80	60	6	40
64	1321.36	60	8	40
65	1321.92	70	5	50
66	1322.48	40	3.8	40
67	1323.04	26	20	20
68	1323.60	20	16	18
69	1324.16	20	16	18
70	1324.72	20	18	19
71	1325.28	26	19	20
72	1325.84	30	20	20

APPENDIX G: Volume of Shale Calculation (Sample Calculation)

a) Gamma Ray Log

$$\begin{aligned} V_{sh} &= \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \\ &= \frac{97.75 - 46.0}{115 - 46.0} \\ &= 0.75 \end{aligned}$$

b) Neutron-Density Log

$$\begin{aligned} V_{sh} &= \frac{\phi_N - \phi_D}{\phi_{NSH} - \phi_{DSH}} \\ &= \frac{0.300 - 0.28}{0.330 - 0.2857} \\ &= 0.45 \end{aligned}$$

c) Resistivity Log

$$\begin{aligned} V_{sh} &= \frac{\log(RES D) - \log(RES D_CLN)}{\log(RES D_SHL) - \log(RES D_CLN)} \\ &= \frac{6 - 4}{8 - 4} \\ &= 0.50 \end{aligned}$$