Scales and Characteristics of Heterogeneity in Sandstone Reservoirs, Miri Field, Sarawak

by

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CHAPTER 1
INTRODUCTION

1.1 Introduction

Reservoir is a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons, oil or gas, which is confined by impermeable rock or water barriers and is characterized by a subsurface, porous, permeable rock body in which oil and gas are stored (Oil Gas Glossary, 2007). A good reservoir is influenced by two important factors. These are the porosity to host oil or gas and the permeability to allow the movement of fluids in the reservoir rock (Allen, 1982). Most reservoir rocks are limestone, dolomites, sandstones, or a combination of these three types of rocks. Dan and Edward (2000) stated that sandstone and carbonate are the dominant reservoir rocks. In particular, sandstone is commonly porous and permeable and therefore a likely type of rock in which to find a petroleum reservoir.

The quality of reservoir is determined by interrelationship between porosity, permeability, thickness, mineral composition, lateral distribution of rock. Therefore, a detailed study on reservoir properties must be derived from the characteristics of reservoir heterogeneity and interpretation of geological and petrophysical data. Reservoir heterogeneity is a formation with different specific and relative permeability characteristics (Ambastha, 1995). Reservoir heterogeneity is variation in rock properties within a single reservoir that affect the flow of hydrocarbons. A number of factors such as pore size distribution, core-scale heterogeneity and the geological structure of rock are known to affect the measured petrophysical properties in core plug samples.

1.2 Significant of study

The interest of studying the scales and heterogeneity characteristics in Miri Field, Sarawak is initiated based on the potential of the reservoir in the Miri Formation to produce high quantity of oil. Since the discovery of the first oil field in Miri Field in year

1910, a total of some fifty (50) exploration wells have been drilled in the West Baram Delta resulting in the discovery of some 1.4 billion barrels of oil and 5.7 trillion cubic feet of gas in 18 oil and gas fields. Nine (9) of these oil fields are currently producing some 100,000 BOPD (Tan *et al.*, 1999). Exploration for oil in Baram Delta commenced in year *1909*. After the abandonment of the well in *1972*, the existence of hydrocarbon in this area is still significant. Initially, most of activities in this area were conducted at onshore, but after 30 years of abandonment, the activities have been shifted toward offshore are. In view of its historical significance, the study of petroleum geology and hydrocarbon habitat of West Baram Delta will give a detailed description of Miri Field. The Middle Miocene Miri Formation crops out around Miri, providing an invaluable surface analogue for the subsurface sediments of the offshore West Baram Delta (Tan *et al.*, 1999). The subsurface rock can be considered as analogue of subsurface sediments due to the geologic evolution, stratigraphy, and trap configuration of the West Baram Delta. Outcrop studies for the subsurface rock regarding facies characterization, lithology, sedimentary structure, and petrophysics data such as porosity and permeability of rock resembles the hydrocarbon pattern in the Miri Formation. Hence, the integration of both geology and petrophysics data can be used for modeling setting which will provide description on formation rock flow behavior. Up to date, no systematic studies which integrate both geology and petrophysics data has been conducted regarding the Miri Formation. This study plays an important role to give detailed information about Miri Formation and can be used as useful tool to predict the reservoir performance in Miri Formation. In addition, the high performance and productive Miri Field and reopening of well in Miri Field, especially in West Baram Delta, has becomes the motivation to study the nature of this formation.

1.3 Problem statement

In order to evaluate the performance and estimate the hydrocarbon production, the main problem occurs when no systematic works which integrates geological information and petrophysical data has been done. The importance of interpreting the relationship between geology and petrophysical data is recognizable since both subjects are related to each other. Previous studies have shown that the geological properties such as sedimentary facies, lithology structure and texture composition of rock is generally related to the heterogeneity of reservoir. It gives significant impact in term of the flow pattern and volume capacity of reservoir. For example, the physical, chemical and biological processes in specific depositional environments and resulting depositional facies determine many attributes that are directly or indirectly related to hydrocarbon generation, migration, entrapment and reservoir productivity (Fisher and Galloway, 1983). However, further systematic studies regarding relationship between sedimentary facies characteristics and petrophysical properties must be conducted particularly in Miri. Therefore, the study will provide two key solutions:

i. Developing the relationship between sedimentary facies and lithology of rock and petrophysical properties to describe how reservoir heterogeneity affects flow of hydrocarbons.
ii. Giving detailed description of Miri field reservoir characteristics through study of formation geological setting and petrophysical properties which further can be developed as reference tool for production in Miri field.

1.4 Objectives of the study

The vital objective of this study is to characterize and quantify the Miri reservoirs by integrating the geology information and petrophysical properties. The objective will be achieved by:

i. Investigating the heterogeneity characteristics in Miri Formation by obtaining geology information such as facies characteristics, sedimentary structure and lithology of the rock sample.
ii. Investigating petrophysical properties which are porosity and permeability of Miri Formation and establishing relationship between them.
iii. Studying and documenting the relationship between the geology information (facies characteristics, sedimentary structure and lithology)

and petrophysical properties (porosity, permeability) in order to characterize the reservoir and understand the heterogeneity of formation.

The resulting data from the establish relationship between geology information and petrophysical properties will provide heterogeneity scales and description of reservoir and act as a reference tool for oil exploration and production activities in Miri field.

1.5 Study area

The scales and characteristics of heterogeneity study area is Miri Field, Miri, Sarawak. The outcrop study is conducted at Canada Hill outcrop, Jalan Oil Well No.1, Miri Sarawak. This area is basically the based part of Canada Hill. The area of study, Miri, is located northeastern Sarawak, northwestern side of Borneo Island. The study area is bounded between latitudes 4^{o}, 18' N and 4^{o}, 27' N and longitudes 113^{o}, 68' E and 114^{o}, 20' E (Figure 1.1). In geological sense, the study area is considered as an extended onshore part of West Baram Delta. West Baram Delta is the western part of the Upper Tertiary Baram Delta province which is roughly triangular in shape, with its apex occurring onshore and centered in Brunei and northeastern coastal area of Sarawak. The province expands offshore to cover the whole width of Brunei waters and encroaches southwest into Sarawak (where it is known as West Baram Delta) and northeast into offshore NW Sabah (which it is named as East Baram Delta) (Tan *et al.*, 1999). The total area is composed of only less than one third of total Baram Delta Province, which is known as Miri oilfield.

Figure 1.1 Satellite map for study area which bounded between latitudes 4^0, 18' N and 4^0, 27' N and longitudes 113^0, 68' E and 114^0, 20' E. (This photo is modified from Google Map Europe Technologies)

1.6 Miri Field exploration history

The exploration of oil in Miri Field began in year 1909 when the first Sarawak Oil Mining Lease was granted to the Anglo Saxon Petroleum Company, an offshoot to the Royal Dutch/Shell Group. The Miri-1 well was spudded on 10 August 1910 and upon completion, the well produced 88 BOPD of light oil (Tan et al., 1999).

By February 1916, 50 wells had been drilled and the Miri Field had reached a cumulative production of 1.25 million barrels, with a daily production rate of some 2, 700 BOPD. However, water and sand problems affected field development for a few years between the year 1916 and 1919. After the problems were resolved, by 1929, a peak of over 15000 BOPD was reached. In the 1930s, production dropped to less than 11, 000 BOPD in 1931 and 2, 400 BOPD in 1941, shortly before Japanese invasion (Tan et al., 1999).

During the war, the Japanese produced a total of 700, 000 barrels. It took two years to bring the field back to stream. Despite efforts to boost production, including field rehabilitation and water injection projects, the field continued to decline. In fact, the field only produced 675 BOPD from 98 wells. Finally, the Miri Field was totally abandoned on 20 October 1972. In 1987, Malaysian Baram Oil Development Company (MBDOC, as operator) and PETRONAS Carigali Sdn. Bhd. were awarded a PSC to explore Block SK14. MBODC acquired 738 km of 2D seismic and drilled five (5) wells, resulting in Asam Paya discovery (Tan et al., 1999).

1.7 Regional geology background of Miri Field

West Baram Delta is the birthplace of the Malaysian oil and gas industry with the first oil field (the Miri Field) discovered in 1910. West Baram Delta is the western part of Upper Tertiary Baram Delta province which is roughly triangular in shape with its apex occurring onshore and centered in Brunei and the northeastern coastal area of Sarawak. Baram Delta Province expands offshore to cover the whole width of Brunei waters, and invades southwest into Sarawak (where it is known as the West Baram Delta) and northwest into offshore NW Sabah (East Baram Delta)(Figure 1.2). The western margin of the Baram Delta is marked by West Baram Line, down to the basin faults that separate the delta from the older Balingian and Central Luconia provinces to the west. The West Baram Delta is characterized by the deposition of a northwestward prograding delta since Middle Miocene times. Periods of delta outbuilding were separated by rapid transgression, represented by marine shale intervals that form the base of sedimentary cycle. From sedimentary views, the regressive sequences of depositional cycle grades northwestwards from coastal-fluviomarine sands to neritic, marine shales.

Since the Middle Miocene, the Baram Delta has been subsiding relative to the more stable Central Luconia and Balingian provinces to the west. Within the Baram Delta, major increases in sedimentary thickness occur across growth faults, which generally trend NE-SW in the main depocentre but swing towards the NW-SE direction. The West Baram comprises up to 9-10 km of Miocene to recent siliclastic sediments derived from south-southeast, along the trend of the present-day Baram river.

The tertiary rocks of onshore northwest Sarawak, adjacent to West Baram Delta, consist of a thick succession of sand-shale sequences with subordinate carbonates. Based on the degree of deformation, these rocks can be subdivided into two main sections *namely (1) an older, deformed sequence of clastics ad subordinate carbonates, ranging in* age Late Cretaceous to Early Miocene, and (2) a younger, more gently deformed sequence of progradational deltaic sediments of Middle Miocene to Quartenary age. The older sequences (Paleogene to Early Neogene) occur in the more interior parts of Sarawak, whereas the upper Neogene deltaic series crop out in the coastal area and extend into offshore. A schematic relationship between the onshore formations and the offshore stratigraphy is shown in Figure. The younger Neogene succession comprises of the Sentap Shale, Lambir, Tukau, and Miri formation.

Following an Early Miocene tectonic event, uplift and erosion were accompanied by the deposition of a thick pile of clastic sediments. Relatively coarse sediments, predominantly sandstones, were deposited in coastal plain, deltaic and coastal environment. A thick argillaceous succession underlies the sandstone sequence was deposited and sedimentation was strongly influenced by tectonic activity. The Neogene formation crops out in onshore northwest Sarawak to form an integral part of clastic wedge, with the arenaceous Lambir, Tukau and Miri formation passing laterally basinward into Setap Shale formation (Figure 1.3)

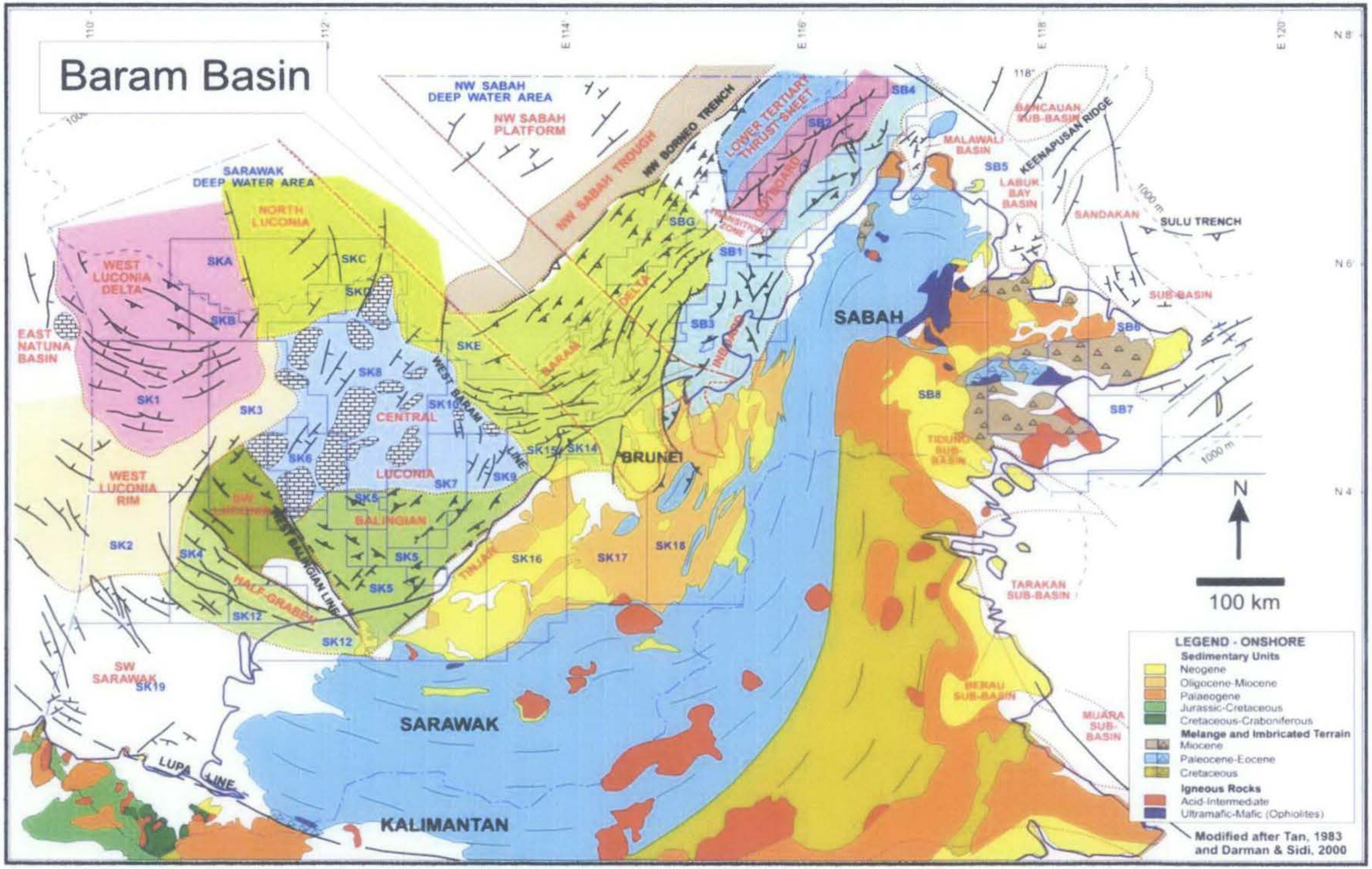

Figure 1.2 Geographical map of northern and eastern continental margin and Baram Basin structural map (Picture courtesy of Petroleum Resource Handbook)

1.7.1 Miri Formation (Middle Miocene Miri)

Miri formation can be subdivided into two parts namely (1) Upper Miri which estimated thickness ranges from 472 to 1310 meters (1550 to 4300 ft) and (2) Lower Miri which estimated thickness ranges from 168 to 1015 meters (550 to 3330 ft). The maximum total thickness is estimated to exceed 1830 meters (6000 ft). Middle Miocene Miri Formation crops out around Miri provides surface analogue for the subsurface sediments of the offshore West Baram Delta. Its outcrops are restricted to the narrow coastal region around Miri. Liechti et. al (1960) and Wilford (1961) subdivided the formation into Lower and Upper unit due to lithological differences and small benthonic foraminifera assemblages.

The Lower Miri unit consists of interbedded shales and sandstones, and passes downwards into the underlying Setap Shale Formation. The Upper Miri Unit is more arenaceous, consisting of rapidly recurrent and irregular sandstone-shale alternations with the sandstone beds passing gradually into clayey sandstone and sandy or silt shale. Figure 1.4 shows the one of the outcrop in Miri Field which is Canada Hill outcrop.

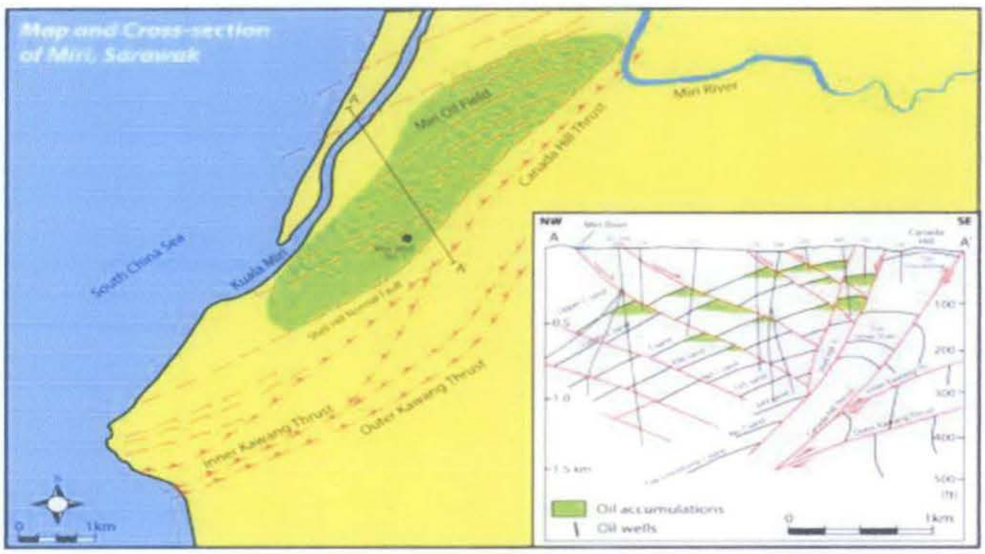

Figure 1.3 A map and geologic cross-section of the Miri field, originally drawn by the Sarawak Shell geologist P. von Schumacher in 1941 and revised by other geologists since then. (Illustration: Rasoul Sorkhabi)

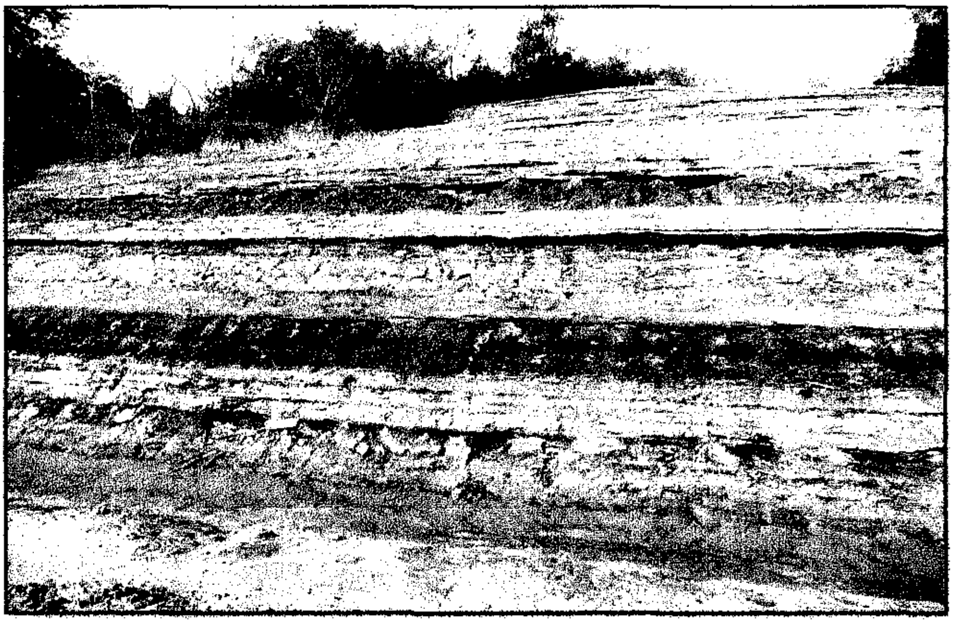

Figure 1.4 An outcrop of the Upper Miocene Miri Formation in Canada Hill deposited by the paleo-Baram Delta. (This picture is taken during fieldwork at Canada Hill outcrop Miri, Sarawak)

Shell assigned a Middle Miocene age to Miri Formation succession. Outcrops of the Miri Formation around Miri provide some realistic insights into the geometry of two main different types of sands namely clayey sandstone and silt shale.

1.8 Structure of dissertation

This report consists of five chapters. Chapter 1 is the introduction of final year project including the significant and objectives of study. Chapter 2 is the literature review on heterogeneity of reservoir and facies characterization. Details of petrophysical properties and related works are addressed in this chapter. Chapter 3 focuses on methodology and the methods used in this work. Formulas and related calculation, sampling and laboratory analysis are discussed in this chapter. Chapter 4 and Chapter 5 is the result of investigation for this project and discussion for this work, by integrating depositional facies characteristic and petrophysical properties to understand heterogeneity of reservoir. *Finally, Chapter 6 includes the conclusion and recommendation for further* study.

CHAPTER 2
LITERATURE REVIEW

2.1 Introduction

Many case studies have been presented to study the relationship between reservoir characteristics and flow performance. Sandstone reservoirs usually contain heterogeneities or mudstone layers that strongly influence flow behavior. The effective permeability of heterogeneous sandstone reservoir has considered a variety of statistical models of mudstones distribution and proposed various semi-analytical for estimating effective vertical permeability. All rocks and formation reservoirs are build up thousand years ago due to changes of depositional environment and migration of sedimentology. Therefore, geological setting includes the depositional environment has formed the internal architecture or rock such as structure of the rock, composition of mineral inside the rock and bedding that occur in rock. The internal architecture of rock is relatively correlated with the behavior and performance of the rock.

2.2 Reservoir rocks

The reservoir is a porous and permeable lithological unit or set of units that holds the hydrocarbon reserves. Analysis of reservoirs at the simplest level requires an assessment of their porosity (the calculation of the volume of hydrocarbon) and their permeability (the calculation of how easy hydrocarbons will flow out of them). All the oil created by the source rock is not useful unless it winds up being stored in an easily accessible container, a rock that has room to store it. A reservoir rock is a place that oil migrates to and is held underground. A sandstone has plenty of room inside itself to trap oil, just like a sponge has room inside of itself to soak up spills in your kitchen. It is for this reason that sandstones are the most common reservoir rocks. Limestones and dolostones, some of which are the skeletal remains of ancient coral reefs, are other examples of reservoir rocks.

2.2.1 Sandstone reservoirs

A sedimentary rock composed of individual mineral grains of rock fragments between 1/16 and 2 millimeters in diameter and cemented together by silica, calcite, iron oxide, and so forth. Sandstone is commonly porous and permeable and therefore a likely type of rock in which to find a petroleum reservoir. Diagenesis alters the original pore type and geometry of sandstone and therefore controls its ultimate porosity and permeability. Early diagenetic patterns correlate with environment of deposition and sediment composition. Later diagenetic patterns cross facies boundaries and depend on regional fluid migration patterns (Stonecipher and May, 1992). Effectively predicting sandstone quality depends on predicting diagenetic history as a product of depositional environments, sediment composition, and fluid migration patterns. As the name implies, sandstone is composed of sand. Sand is characterized by any grain that is 0.1 mm to 2.0 mm in size. The nature of sand formation is usually important to geologists and the minerals or rocks that are in it are critical to determine where the source of sandstone's composition came from. The roundness of the grains is also important in determining the amount of distance the sand has been tumbled before deposition or the closeness of the source to the final deposit. The lack of fine grains and mud in a sandstone indicates a relatively high energy environment of deposition such as the wave action on a beach, the wind sweeping across a sand dune field or the rush of a river current.

2.2.2 Reservoir heterogeneity

Reservoir heterogeneity is defined as variation in rock properties within a single reservoir that affect the flow of hydrocarbons. Characterizing reservoir heterogeneity is important for the understanding and optimization of production of oil and gas reservoirs.

Reservoirs can contain impermeable lithological units and heterogeneous porosity/permeability distributions that are further affected by complex fault systems that significantly affect fluid flow paths and distribution. Reservoir heterogeneity occurs at the metre-scale, where heterogeneities are controlled by bedding, fluid changes, and diageneitc effects. Heterogeneities occur at larger scales also, but at the metre-scale heterogeneities affect fluid flow behavior the greatest (Grammer et. al, 2004). Reservoir heterogeneity exists at all scales namely grains, laminae, bed and sand body. Sedimentary structures include lamination, bedding, bioturbation, grain size and sorting. Structural causes of permeability anisotropy meanwhile include the joints, fractures, faults and shear zone. Consequently, the differences of heterogeneity affect the capacity of hydrocarbon contains in rock, permeability and flow channels due to structural variation in formation reservoir.

2.3 Classification of main type and scales of heterogeneity in sandstone reservoir

Reservoir engineering studies rely heavily on measurements from a few small samples from reservoir rock formations. The estimation of reserves and recoverable hydrocarbon for a whole field may depend quite strongly on the values determined for petrophysical properties from limited core dataset. Heterogeneity within clastic sediments is best classified in terms of the types of depositional processes that resulted in their formation. Figure 2.1 simplified classification of the main genetic units that occur within sandstones. For many purposes, including facies correlation and fluid flow scale up, genetic units are best defined at the bedscale (eolian or fluvial crossbeds, ripple lamination). At this scale, the depositional processes can be classified in terms of a series of universal or genetic architectures that can be recognized in a wide variety of geological setting.

At larger scales, the arrangements of sediment architecture depend on details of depositional and tectonic environment prevailing at the time of deposition, and at this scale every system is virtually unique, although general classes of depositional environment can be defined. At a smaller scale, a single nearly universal phenomenon lamination can be found. Virtually all sands posses some degree of lamination. Some examples of realistic sedimentological settings from which a core plug may be taken are *shown in Figure.* The facies shown in this figure are cross bedded, ripple-laminated, planar laminated unit, all of which are common in sediments.

Heterogeneity Type		Lamina scale	Bed scale		Reservoir scale	
Depositional Environment	Genetic Bedforms	Typical Lamina Permeability Contrasts	Bedform Geometry (Bed height)	Bedform Permeability Trends	Reservoir geometry	Stacking patterns characteristics
Aeolian	Dunes (barchan, seif) Interdune deposits (wind-ripples, adhesion lamina) Fluvial sheets	High lamina contrasts (typically 1 to 2 orders of magnitude)	(2-10m)	k		Dunes comprise nests of different angle laminasets bounded by interdune layers
Alluvial fans	Sheets (breccias, conglomerates, debris flows, sand sheets)	Matrix and clasts may be internally laminated Permeabilities are highly variable	(0.1 to 5m)	matrix clast		Laterally-extensive layers. Layer thicknesses vary
Fluvial	Crossbeds (trough, tabular, chaotic) Low-angle strata Ripple-bedded strata Convoluted-beds (and dewatering structures)	Moderate lamina contrast (typically 10:1) Both tangential and normal grading occurs Dewatering increases lamina contrasts	(0.1 to 1m)	k k		Channel stacking patterns (braided, meanders, etc). Relationship of channels to overbank/floodplain deposits.
Deltaic	Crossbeds (tabular) Bars (mouth, swash)	Moderate lamina contrast (typically 10:1)	(0.5 to 10m)	k		Moderately extensive formations cut by distributary channels
	Ripple-bedded sand sheets (prodelta)	Low lamina contrasts (5:1)	(0.05m)	k		Morphology of bars and delta front
	Sand-sheets, coal-sheets, soils, etc (delta plain)	Beds often massive, but k contrasts between beds is very high	(1 to 5m)	k		
Shallow marine	Hummocky cross stratifn (&SCS) Tidal bars Bioturbation	Moderate to low lamina contrasts (10:1 to 5:1)	(0.2 to 1m)	k		Very extensive units, strongly affected by water-depth history.
Deep-water clastics	Turbidites Debris flows Slumps Contourites	Mainly massive or graded beds, often showing dewatering structures	(0.1 to 1m)	k		Laterally extensive units, cut by (very erosive) channels

Figure 2.1 Classifications of the main genetic units that occur within sandstones.(This image is taken from Archer, J.S. 1983, *Reservoir Definition and Characterization for Analysis and Simulation*, Eleventh World Petr. Cong., London, pD 6(1))

2.4 Sedimentology and Facies Characteristics of Sandstone

Generally, facies are distinguished by what aspect of the rock or sediment is being studied. Thus, facies based on petrological characters such as grain size and mineralogy is called lithofacies, whereas facies based on fossil content are called biofacies. Sedimentary facies is defined as a unit of rock that is distinguished by its individual sedimentological character. Its individuality is a combination of all or some of the following characteristics such as sedimentary structures, fossil content, lithology, geometry and paleocurrent pattern (Reineck & Singh, 1980; Tucker, 1981; Selley, 2000). Sedimentary facies reflects the physical, chemical and biological conditions and processes of the depositional environment

2.4.1 Sedimentary Structures

Sedimentary structures reflect the hydrodynamic processes during deposition and they are simply divided into primary and secondary classes. Primary structures are those generated in sediment during or shortly after deposition and result mainly from the physical processes (e.g. current and waves). Examples of sedimentary structures are ripples, cross-bedding and slumps. Secondary sedimentary structures are formed sometime after sedimentation and result from essentially chemical processes, such as those which lead to the diagenetic formation of concretions.

Primary sedimentary structures are divisible into inorganic structures and organic structures (Figure 2.2) and the division between the various groups provides a useful framework on which to build the analysis of sedimentary structures (Selley, 1988). Sedimentary structures can be studied at the outcrop and in cores taken from wells. There are two basic approaches to observe sedimentary structures. The first approach is to pretend the outcrop is a bore hole and to measure a detailed sedimentological log while the second approach is a two-dimensional survey of all, or a major part, of the outcrop.

I.	Primary (physical)	Inorganic	Fabric Cross-bedding, ripples, etc.	Microscopic
		Organic	Burrows and trails	Megascopic
II.	Secondary (chemical)	Diagenetic	Concretions, etc.	

Figure 2.2 Classification of sedimentary structures

2.5 Lithology and texture

Lithology is a function of transportation processes and the macroscopic nature of the mineral content, grain size, texture and color of rocks. The characters of reservoir rocks vary based on their sedimentary textures that are produced by depositional and diagenetic processes. The term texture has a broad meaning and refers to the interrelationships among the population (Krynine, 1948). Texture is also considered as a main factor controlling some petrophysical properties, such as porosity and permeability. The principal elements of texture are grain size and sorting and these elements are the commonly measured elements.

2.5.1 Grain Size

Grain size refers to the diameter of a grain of granular material, such as sediment or the lithified particles in clastic rock. Granular material can range from very small colloidal particles, through clay, silt, sand, and gravel, to boulders. In contrast, crystallite size is the size of a single crystal inside the grain. A single grain can be composed of several crystals. For many years, the size and distribution of the sand and gravel fractions were determined solely by sieve analyses. After the sieve analyses, the sample is separated into classes or groups. The classes are designated by logarithmic units or phi classes for statistical purposes (Figure 2.3). In general, the grain size of sediments is a sign of the hydraulic energy of the environment. During the transport, movement and sedimentation, grains change their shape which is described by parameters of sphericity and roundness.

φ values	Particle diameter (mm diam.)	Wentworth grades		Rock name
		Cobbles		Conglomerate
−6	64			
		Pebbles		
−2	4			
		Granules		Granulestone
−1	2			
		Very coarse	sand	Sandstone
0	1			
		Coarse		
1	0·5			
		Medium		
2	0·25			
		Fine		
3	0·125			
		Very fine		
4	0·0625			
		Silt		Siltstone
8	0·0039			
		Clay		Claystone

Figure 2.3 Wentworth grade scale for sediments

2.5.2 Sorting

Sorting is the degree of uniformity of grain size. Particles become sorted on the basis of density, because of the energy of the transporting medium. High energy currents can carry larger fragments. As the energy decreases, heavier particles are deposited and lighter fragments continue to be transported. This results in sorting due to density. If the particles have the same density, then the heavier particles will also be larger, so the sorting will take place on the basis of size. We can classify this size sorting on a relative basis well sorted to poorly sort (Figure 2.4). Sorting gives clues to the energy conditions of the transporting medium from which the sediment was deposited.

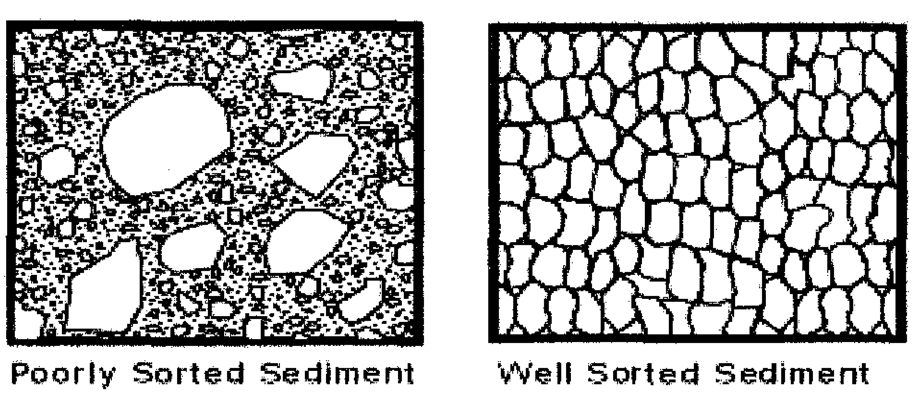

Figure 2.4 Classification of sediment sorting from poor sorted until well sorted

2.6 Petrophysical Properties

Petrophysics involve the investigation and study of the physical behavior and properties of rocks (Yale, 1985). It is a highly interdisciplinary field incorporating geology, well logging, core analysis, geophysics, geochemistry and sedimentology. This subject involves the study of the physical properties of rock which are related to the pore and fluid distribution (Archie, 1950). This generally refers to four properties of rocks: porosity, velocity, bulk density, and permeability.

2.6.1 Porosity

Porosity is a measure of storage capacity of a reservoir. Porosity also can be defined as the percentage of pore volume or void space, or that volume within rock that can contain fluids. Porosity can be a relic of deposition (primary porosity, such as space between grains that were not compacted together completely) or can develop through alteration of the rock (secondary porosity, such as when feldspar grains or fossils are preferentially dissolved from sandstones) (Figure 2.5). The porosity is calculated as ratio of the pore volume to the bulk volume (total volume).

$$\text{Porosity} = \frac{\text{Pore Volume}}{\text{Total Volume}}$$

$$\text{Porosity} = \frac{\text{Total Volume} - \text{Solid Volume}}{\text{Total Volume}}$$

The primary porosity of unconsolidated sediments is determined by the shape of the grains and the range of grain sizes present. In poorly sorted sediments, those with a larger range of grain sizes, the finer grains tend to fill the spaces between the larger grains, resulting in lower porosity. Primary porosity can range from less than one percent in crystalline rocks like granite to over 55% in some soils. The porosity of some rock is increased through fractures or solution of the material itself. This is known as secondary porosity.

2.6.2 Permeability

Permeability is a property of a porous medium and is a measure of its ability to transmit fluids (Figure 2.6) The reciprocal of permeability represents the viscous resistivity that the porous medium offers to fluid flow when low flow rates prevail. The permeability calculation is based on Darcy's Low which uses the relationship between the permeability of a porous media and the potential gradient observed during the flow of a fluid through it this method is based on transient pressure technique for gases.

$$Q = \frac{kA(p_b - p_a)}{\mu L}$$

Darcy's law is a simple proportional relationship between the instantaneous discharge rate through a porous medium, the viscosity of the fluid and the pressure drop over a given distance. The total discharge, Q (units of volume per time, e.g., ft^3/s or m^3/s) is equal to the product of the permeability (κ units of area, e.g. m^2) of the medium, the cross-sectional area (A) to flow, and the pressure drop ($P_b - P_a$), all divided by the dynamic viscosity μ (in SI units e.g. kg/(m·s) or Pa·s), and the length L the pressure drop is taking place over.

2.6.3 The relationship between porosity, permeability and rock texture

Permeability is a fundamental property of rocks for the managing of geothermal reservoirs as well as for the understanding of geological processes involving fluid flow. According to the Kozeny-Carman equation, permeability is related to porosity, tortuosity and the hydraulic effective pore radius, which represent different aspects of pore space geometry. Permeability can be related to porosity on condition that an adequate pore space model is applied which reflects the diagenetic rock type.

In the earth, rocks and their pore space evolve according to various geological processes (e.g., compaction during burial, depressurization and cooling during uplift, diagenesis and metamorphic reactions, deformation under tectonic stresses). Some of these processes produce pores and others destroy them; all change permeability. Thus, each process defines a specific evolution permeability-porosity relationship.

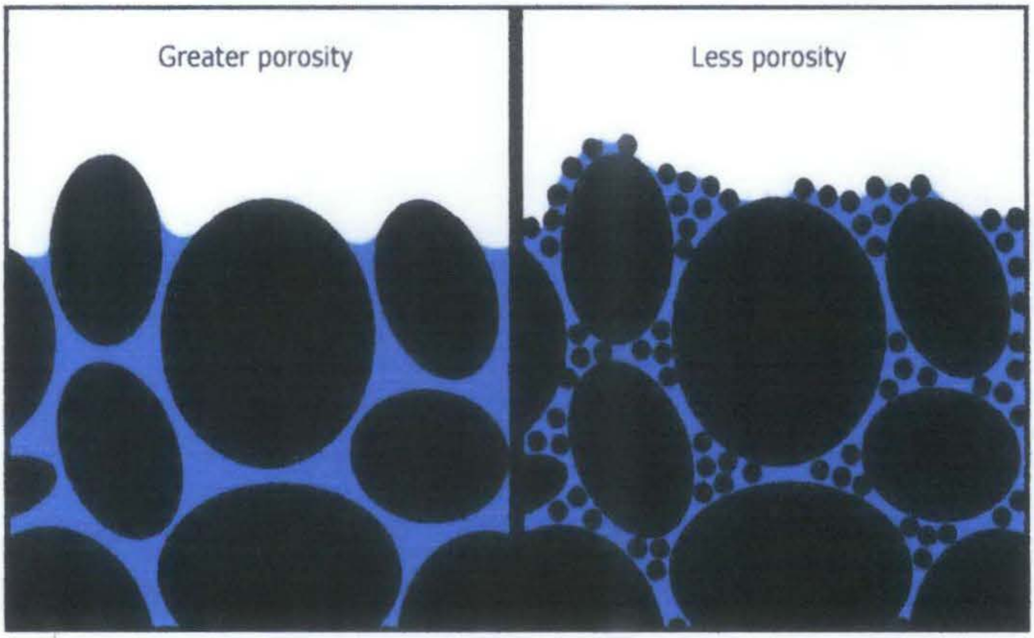

Figure 2.5 Comparison between good and bad porosity in reservoir. Less porosity results less storage capacity for hydrocarbon

CHAPTER 3
METHODOLOGY

3.1 Introduction

The main purpose of this chapter is to present all the methods that will be used in studying the heterogeneity and characteristics of reservoir. Therefore, this chapter plays a vital role in developing systematic approach that is applied during laboratory analysis. Several formulas and calculations, tools and hardware used are discussed in this chapter. The proposed methodology starts from rock sampling until laboratory analysis.

3.2 Rock Sampling

Core analysis has come a long way from the days when reservoir productivity was determined by blowing through a piece of cable tool- produced core. Our tools and methods for drilling and core analysis have changed, but our interests have not. The reservoir rock properties that determine hydrocarbon production, the variation in these properties, and how these properties affect ultimate recovery are still of primary concern. Properly engineered core analysis provides a direct measurement of these reservoir-rock properties and is an essential step in formation-evaluation, reservoir, and production engineering. Core analyses must integrate with field and production data and eliminate reservoir uncertainties that cannot be addressed with log, well-test, or seismic data. These requirements define the coring objectives that, in turn, control coring fluid, tools, and core handling. In most cases, these objectives cannot be obtained with core retrieved in a single well. Coring is thus an integral part of the reservoir-life-cycle process, with cored wells selected to verify or provide maximum information for the current geological, engineering, or production model of the reservoir.

3.2.1 Sedimentological logging of outcrop

Sedimentary logging of 1 cm: 100 cm scale (refer to Chapter 4 Figure 4.2) is applied method for rock outcrop. Based on field observation, several factors need to be considered namely bed thickness, geometry, lithology, sedimentary structures and fossils. Photographs of outcrop will be taken to help clarify the lithology distribution. Once sedimentary logs have been established, deposits will be assigned to distinct number of lithofacies based on interpretation and the analysis of sedimentary features and their depositional processes.

3.2.2 Collection of sample

Samples from different area will be collected from investigated outcrops surface with a hammer and a chisel during field trip. Stratigraphic locations of sample is marked on sedimentological graphic log. The next planning for sample collection should be label of the sample. The samples are given numbers according to their place in the outcrop from the base to the top, with a small arrow pointing to the stratigraphic top of each sample. A brief description of each specimen according to its lithology and lithofacies will be performed during logging and sample collecting. In the laboratory, the samples is trimmed in regular geometric shape in order to calculate the sample dimensions for various petrophysical experiments. Figure 3.1 shows the collection of sample process. A total of 30 samples have been taken during fieldwork.

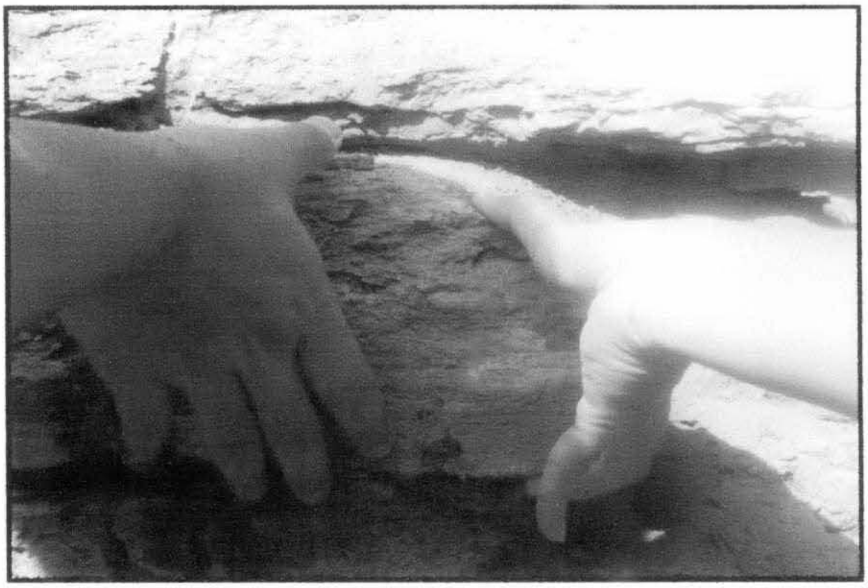

Figure 3.1 shows the collection of sample process.

3.3 Laboratory analysis

Samples will be chosen from different sandstone lithofacies to achieve the laboratory analysis, which involved petrophysical analysis.

3.4 Petrophysical analysis

Petrophysical properties of sedimentary rocks are influenced by porosity and permeability; these properties are partly controlled by facies characteristics which in turn are related to depositional processes. To predict the movement of hydrocarbon in a reservoir, the transport of contaminants in an underground aquifer or weathering processes and stone decay in numerous architectural structures, these petrophysical properties are very important and needed.

3.5. Porosity determination

Porosity is a measure of storage capacity of a reservoir. The porosity is calculated as ratio of the pore volume to the bulk volume of the core sample:

$$Porosity = \frac{Pore..Volume}{Bulk..Volume} = \frac{Bulk..volume - Grain.Volume}{Bulk..Volume}$$

The pore volume is the volume in the sample that can be filled with a fluid. The advantages of determining this volume with mercury is that invasion of the sample are rather easy (due to the small size of the molecule and the low viscosity of the gas) and that the sample remains clean (not spoiled by oil or other liquid). For regular cylinders, the bulk volume is the cylinder volume of the core sample. The matrix cup can accommodate irregular core sample. In this case the bulk volume must be determined from mercury immersion for instance. Grain volume is the volume of solid of the sample. During the experiment, it is determined as the difference of a reference volume without and with the sample. Porosity of core plug sample is determined by using the Porosimeter.

3.6 Tools and hardware requirement

No	Major Equipment/Software	Details
1	Porosimeter	An instrument for measuring the pore volume, and hence the porosity, of a core sample. An instrument for measuring the pore volume, and hence the porosity, of a core sample.
2	Hammer and chisel	To obtain sample from fieldwork
3	Camera	Photograph of the outcrop and special features
4	Measurement tape	Measure thickness of rock

3.7 Project activities

Figure 3.2 illustrates the key milestone for the whole activities conducted throughout FYP 2. The purpose of this semester project is to focus on experimental work and finalize the literature review of project before submitting final report. Figure 3.3 is the Gantt Chart for the whole FYP.

No	Action Item	Action By	Date	Note
1	Briefing & update on students progress	Coordinator / Students / Supervisors	8 February 2011	Week 3
2	Project work commences	Students		Week 1 -8
3.	Submission of Progress Report	Students	16 March 2011	Week 8
4.	PRE-EDX combined with seminar/ Poster Exhibition/ Submission of Final Report (CD Softcopy & Softbound)	Students / Supervisor / Internal Examiner / Coordinator	4 April 2011	Week 11
5.	EDX	Supervisors / FYP Committee	11 April 2011	Week 12
6.	Final Oral Presentation	Students / Supervisors	20 April 2011	Week 13
7.	Delivery of Final Report to External Examiner / Marking by External Examiner	FYP Committee / Coordinator	20-27 April 2011	Week 14
8.	Submission of hardbound copies	Students	04 May 2011	Week 16

Figure 3.2 illustrates the key milestone for the whole activities conducted throughout FYP 2.

		Week/Month																																			
		Year 2010 (FYP 1)																				Year 2011 (FYP 2)															
No	Activities	August				September				October				November				December				January				February				March				April			
		1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
1	Introduction to FYP																																				
2	Selection of FYP Topic																																				
3	Preliminary Research Work																																				
4	Submit Prelim Report																																				
5	Literature Review – Research Work																																				
6	Progress Report																																				
7	Interim Report / Final Draft																																				
8	Presentation																																				
9	Planning for Sample/Core Plug																																				
10	Site Visit to Miri field																																				
11	Lab verification																																				
12	Photo/Sample labelling																																				
13	Coring/Rock identification																																				
14	Porosimetry																																				
15	Grain Size Analysis																																				
16	Thin section																																				
17	Result Analysis																																				
18	Pre EDX																																				
19	EDX																																				
20	Final oral presentation																																				
21	Delivery of final report																																				

Figure 3.3 is the Gantt Chart for the whole FYP

CHAPTER 4
RESULT

4.1 Introduction

This chapter presents all the results from field and experimental work. Data obtained from fieldwork and experimental works are presented systematically, starting from the result from fieldwork until the analysis of sample in laboratory. Several combined sedimetological and petrophysical studies have been performed by many authors for numerous reservoir heterogeneity analysis purposes (Tan *et al.*, 1999; Weber; 1997; Berg, 1986; Walton *et a*l., 1986; Reifensthul, 2002). It is widely known that facies characteristics which are the product of depositional environment control the petrophysical properties of sandstone.

Reservoir heterogeneity is analyzed at number of scales. The scale of heterogeneities plays an important role in determining the level of heterogeneity impact towards fluid flow and porosity. Thus, the scale taken for this project will be described in this chapter. Graphical presentation for all data includes grain size and sieving report, porosity and permeability trend for selected facies also included in this chapter to explain the characteristics of heterogeneity in Canada Hill.

4.2 Scales of Heterogeneities

The overall structure of this report comprises of three main parts namely field analysis, textural analysis and petrophysical measurement. Field analysis refers to the studies of physical properties of the outcrop and include the identification any flow barrier, bedding and laminations. Outcrop analysis is very important in describing the variations of rock that present in Canada Hill area. Sedimentary textures refer to the interrelationships among the population (Krynine, 1948). Texture is also considered as a main factor controlling some petrophysical properties, such as porosity and permeability. The principal elements of texture are grain size and sorting and these elements are the *commonly measured elements. Petrophysical study is the measurement of physical* properties of rock which is the porosity of the rock.

4.3 Field Analysis

Field analysis refer to the analysis of physical properties of the rock and the presence of structures such as bedding and bed forms ripples mark, and fault which are resulted from depositional process. Process in identification, description, classification and interpretation of sedimentary structures is important in order to understand how specific sedimentary structures are related to such aspect of depositional environment, water energy, and flow directions.

4.3.1 Identification of facies at Canada Hill outcrop

In geology, facies is a body of rock with specific characteristics (Reading, 1996). Ideally, a facies is a distinctive rock that forms under certain conditions of sedimentation, reflecting a particular process or environment. Ten facies has been identified at Canada Hill outcrop which is located at Jalan Oil Well No.1, Miri, and Sarawak. The identification of facies is based on different physical structures of rock such as the presence of bedding, mud lamination, textures and colors and obvious differences between rock types. Identification of facies is the basic or the first stage of fieldwork which further will assist in the selection of sample for laboratory work. Figure 4.1 and Figure 4.2 shows ten (10) facies which was identified at this outcrop. Figure 4.2 is the sedimentological logging for the outcrop.

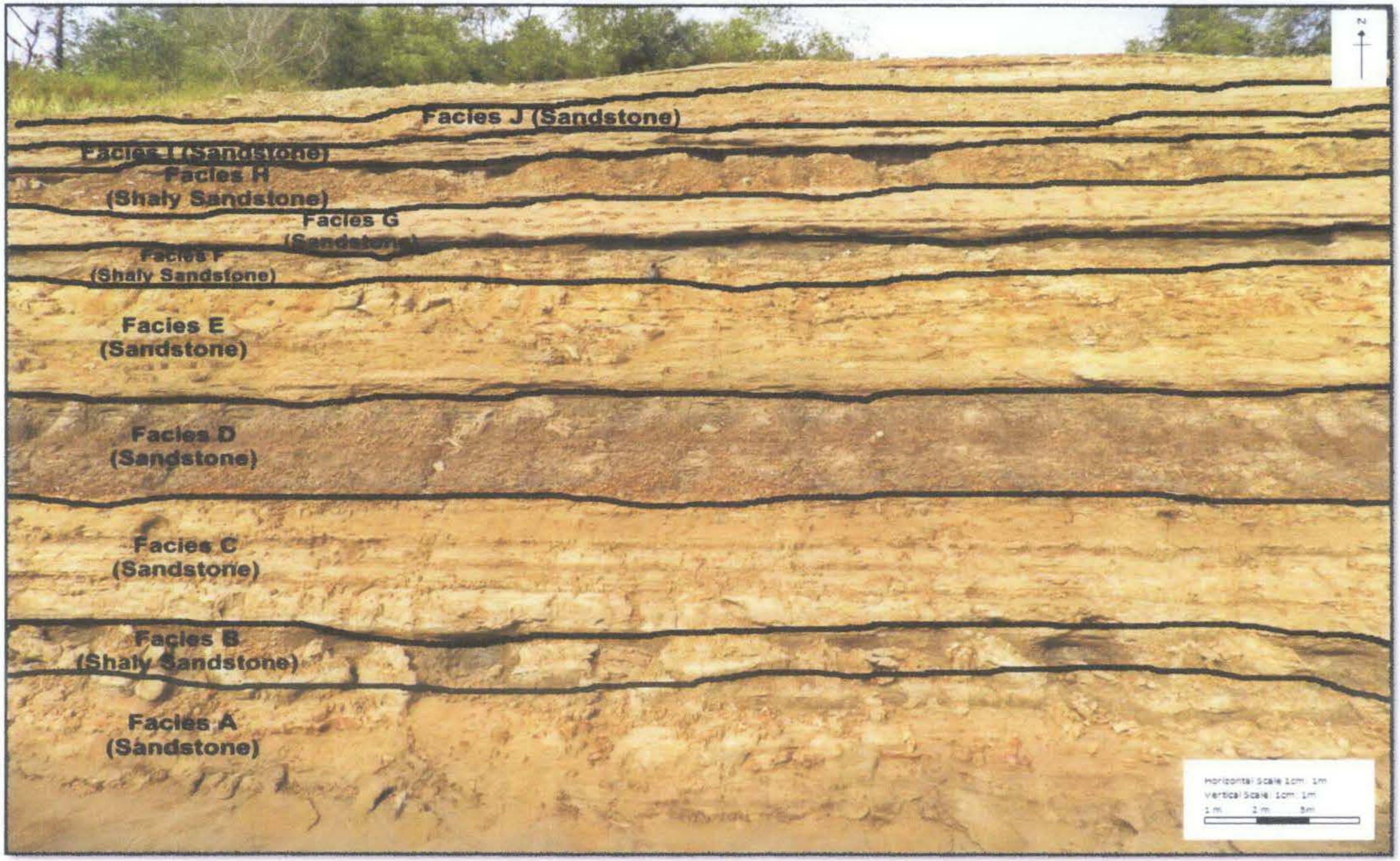

Figure 4.1 Distribution of ten facies at Canada Hill, Jalan Oil Well No.1. This is the front view of the outcrop from left to right. This picture is taken during fieldwork at Miri on January 2011 (Scale of image is 1 cm: 1m)

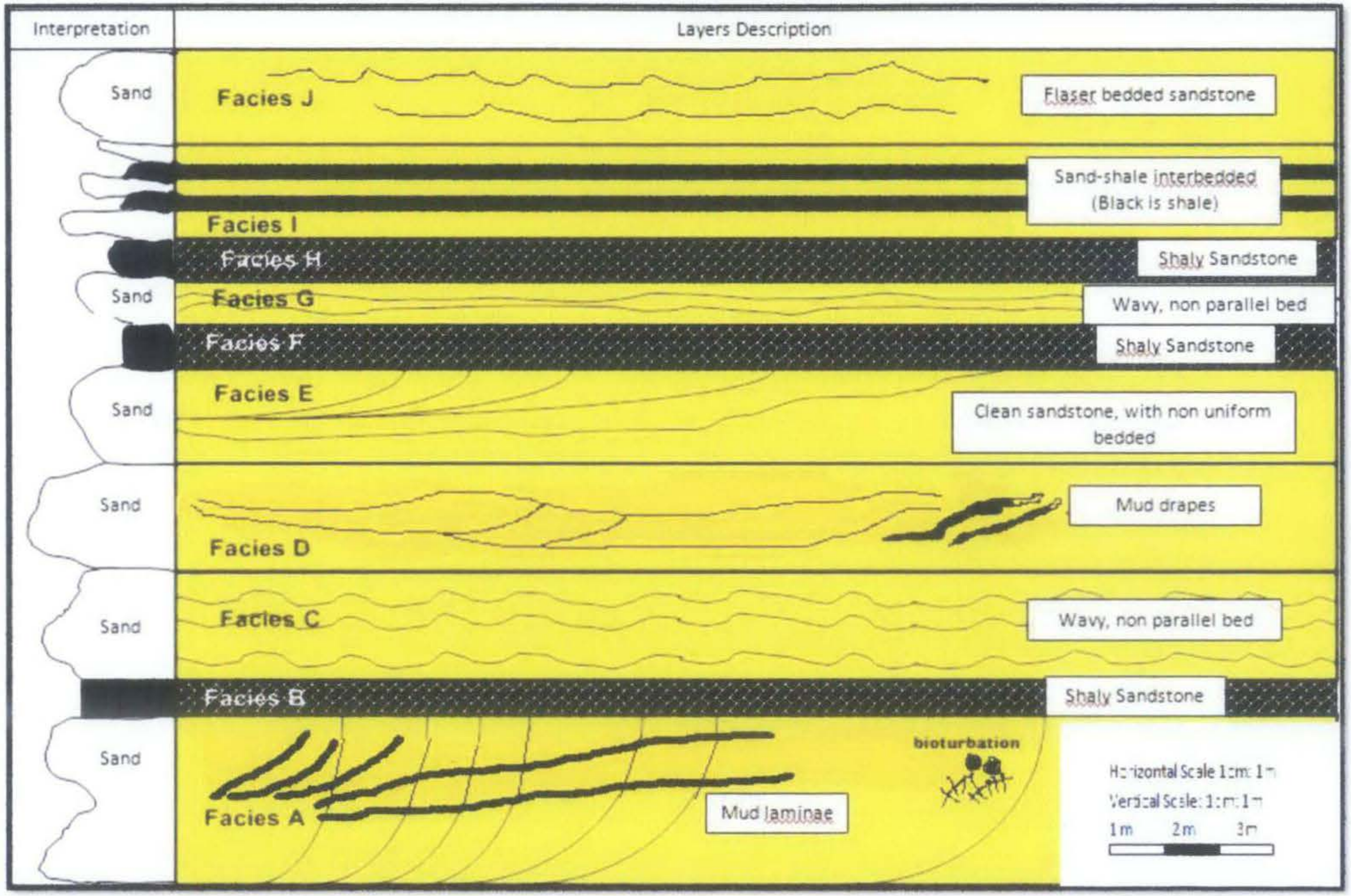

Figure 4.2 Sedimentological logging of the ten facies identified at Canada Hill outcrop. (Scale of the image is 1cm: 1m for horizontal and vertical direction)

Facies A is at the bottom part of the outcrop and identified as thinly-bedded, sand shale alternation unit. It consists of yellowish sandstone with the presence of shale lamination and bioturbation (Figure 4.3(a)) at this facies. Along 30 meters of the selected outcrop, among the significant features are laminated bedding type which coarsening upwards. Facies B is the laminated mudstone facies (Figure 4.3(b)) which is characterized by very fine sand to silty laminations of 15 centimeters thickness. The background mud stone is dark grey or grayish black.

Facies C is the wavy, nonparallel bedding sandstone (Figure 4.3(c)). It is simple cross bedded type of bedding with cross-beds features. It consists of small grain size, hard texture with lamination of grayish and yellowish sandstone. Facies D is mud-draped sandstone. The sandstone is coated with thin, black mud drapes. Facies E is massive coarse sandstone facies consists of poorly sorted, medium to coarse grained sandstone with no internal structures. The most characteristic features of this facies are the collapse structure of rock.

Facies F is the mudstone-dominated facies. This facies consists of mud stone lithologies with up to 50% sandstone intercalations and is generally non reservoir although minor porosity or permeability may occur in some of the sandier layers. Facies G is clean whitish sandstone. Only small bedding which is not obvious can be seen at this facies. Facies H is the mud-draped sandstone (Figure 4.3(d)). Although it looks almost similar to Facies D, the mud drape is thicker than Facies D (almost 20cm thick) with yellowish sandstone under mud draped. Facies I is the interbedded mud and sandstone (figure 4.3(f)). The bedding type is fining upwards and non erosional bounding surfaces. Facies J is the flaser-bedded sandstone. The single horizon of flasered bed occurs as the top part of heterogenous sandstone.

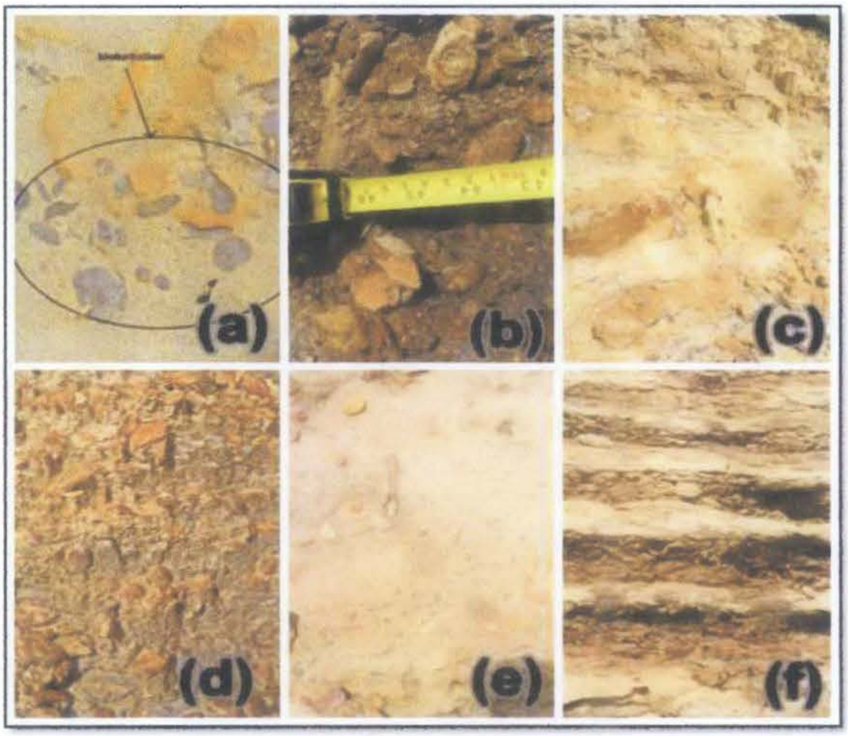

Figure 4.3(a)

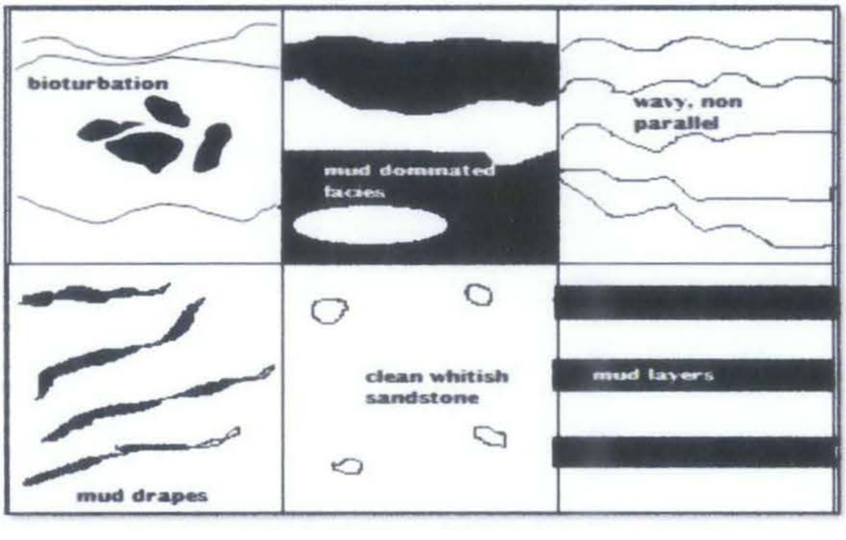

Figure 4.3(b)

Figure 4.3(a) shows (a) bioturbation at facies A (b) laminated mudstone at facies B (c) wavy, non parallel bedding surface at Facies C (d) facies H mud drape sandstone *dominate the facies (e) clean whitish sandstone at Facies G and (f) interbedded mud and* sandstone. Figure 4(b) is the sketch of Figure 4(a).

4.3.2 Thickness of facies

During the fieldwork, the thickness of every facies is taken. The size of the outcrop is estimated to be around 60-70 meters and consists of two level of outcrop. However, upon considering the existence of fault (which indicates the differences of reservoir) the fieldwork focus on 30 meters long outcrop. The selection is based on the variations of lithologies and unique features along the selected area. Table 4.1 shows the thickness of every layer.

Facies	Characteristic	Geometry	Thickness (m)
A	Thinly-bedded, sand shale alternation unit	Uniform	0.35
B	Laminated mudstone facies	Uniform	0.27
C	Wavy, nonparallel bedding sandstone	Uniform	1.20
D	Mud-draped sandstone	Non-Uniform	1.10-1.18
E	Massive coarse sandstone facies	Non-Uniform	1.89-2.02
F	Mudstone-dominated	Non-Uniform	0.85-0.91
G	Clean whitish sandstone.	Uniform	1.71
H	Mud-draped sandstone	Uniform	2.43
I	Interbedded mud and sandstone	Uniform	2.07
J	Flaser-bedded sandstone	Uniform	0.39
Total thickness		Uniform	12.53

Table 4.1 shows the measured thickness of every facies

Total thickness is approximately 13 meters and the horizontal length is 30 meters. From the measured thickness, the thickest layer is Facies H which consists of mud-draped sandstone. Interbedded mud and sandstone recorded the second highest thickness among the facies.

4.3.3. Lateral Continuity

Sedimentary rocks are composed of fragments of preexisting rocks that have been both mechanically and chemically weathered. Before lithification, these fragments are first transported to depositional areas where they are spread out over continuous and sometimes quite extensive geographic areas. Typically these sediments will spread out until they terminate by thinning out at the edge of the depositional basin, abruptly stop at a barrier, such as a shoreline separating the terrestrial environment from the marine or lacustrine environment and grade into a different type of sediment. The grading of one type of sediment into another is often indicative of a change in the energy level within the depositional environment. Sandstones typically grade into shales as the sediments are transported further away from what was the original shoreline. The currents diminish further from the shoreline limiting the size of the particles that can be transported out to sea. The significance of knowing that sedimentary beds are laterally continuous lies in the recognition that similar rock units at different locations may, in fact, be the same although they are now not connected. Faulting, severe folding and erosion may have separated the originally continuous beds into what now appears to be separate units.

Facies	Characteristic	Geometry	Lateral continuity (Range in meters)
A	Thinly-bedded, sand shale alternation unit	Non-uniform	15-20 m
B	Laminated mudstone facies	Uniform	10 m
C	Wavy, nonparallel bedding sandstone	Non-uniform	20-25 m
D	Mud-draped sandstone	Non-uniform	25-30 m
E	Massive coarse sandstone facies	Non-uniform	25-30 m
F	Mudstone-dominated	Uniform	20 m
G	Clean whitish sandstone.	Uniform	25 m
H	Mud-draped sandstone	Non-uniform	20-30 m
I	Interbedded mud and sandstone	Uniform	25 m
J	Flaser-bedded sandstone	Non-uniform	15-20 m

Table 4.2 shows lateral continuity for every facies

4.4 Lithology and textures

Detailed information from lithology is regarded as one of considerable environmental significance. Lithology is considered as a function of transportation processes and of the type of rock from which it was originated. Rock texture is referred to be as a part of lithology study that holds many important clues to its depositional environment and processes. Texture is also considered as a main factor controlling some petrophysical properties such as porosity and permeability. Sediment texture is concerned with the grain-size and its distribution, shape and fabric.

4.4.1 Grain Size

In general, the grain size of sediments is a sign of the hydraulic energy of the environment, where the finer sediments are transported by slower-flowing currents and tend to accumulate in quieter environments whereas the coarser sediments are transported and deposited by faster-flowing currents. In Canada Hill outcrop studies, sands are measured by sieving. The sieves are arranged in downward decreasing mesh diameters. The weight of sediment retained on each sieve is measured and converted into a percentage of the total sediment sample. This method is quick and sufficiently accurate for most purposes. It measures the maximum diameter of a sediment grain. Four aspects have been studied in experimental work such as sorting, mean grain size, kurtosis, and skewness.

4.4.1.1 Mean Grain Size

In most research on sediments, grain-size data is given in phi (Ø) intervals rather than in microns, millimeters or inches. One phi unit is equal to one Udden-Wentworth grade. Phi diameter is computed by taking the negative log of the diameter in millimeters. Mean grain size is the average particle size and can be measured using statistical parameters Folk & Ward formula. The classification of grain size is based on Table A (Appendices).

$$Graphic\ Mean\ (M) = \frac{\emptyset 16 + \emptyset 50 + \emptyset 84}{3}$$

Where:

$\emptyset 16$ = the values of phi at 16%

$\emptyset 50$ = the values of phi at 50%

$\emptyset 84$ = the values of phi at 84%

The grain size for every particle can be obtained after cumulative arithmetic curve is created. The grain size for all facies is summarized in Table 4.3.

Facies	Characteristic	Graphic Mean (M)	Classification
A	Thinly-bedded, sand shale alternation unit	1.787	Medium sand
B	Laminated mudstone facies	1.21	Medium sand
C	Wavy, nonparallel bedding sandstone	1.813	Medium sand
D	Mud-draped sandstone	1.433	Medium sand
E	Massive coarse sandstone facies	2.223	Fine sand
F	Mudstone-dominated	2.30	Fine sand
G	Clean whitish sandstone.	1.727	Medium sand
H	Mud-draped sandstone	1.402	Medium sand
I	Interbedded mud and sandstone	0.797	Coarse sand
J	Flaser-bedded sandstone	2.12	Fine sand

Table 4.3 shows the classification of grain size for every facies

From Table 4.3, it is known that most of facies at Canada Hill consists of medium sand. Facie E, F and J are considered as fine sand. Only Facies I consists of coarse sand. In general, the highest mean grain size is Facies F which is 2.30. Fine sand are transported by slower flowing current which may be the reason why mudstone dominate Facies F. Slower flowing current gives time for mud accumulation on top of sandstone.

For every layer, the histogram chart shows the mode class or which consists of the highest grain size value. Figure 4.4, Figure 4.5, and Figure 4.6 are the examples of three histogram chart from different classification of sand. For Figure 4.4, facies A is the medium sand type. This can be seen from the chart that the mode class typically occurs at Phi 2 and Phi 3. Although the mode class is Phi 2, the average grain size is 1.787 which is slightly lower than the mode Phi value. The trend of high Phi is at center position, while the negative Phi and larger Phi scale such as 4 and 5 record lower percentages compared to Phi value at center (1-3).

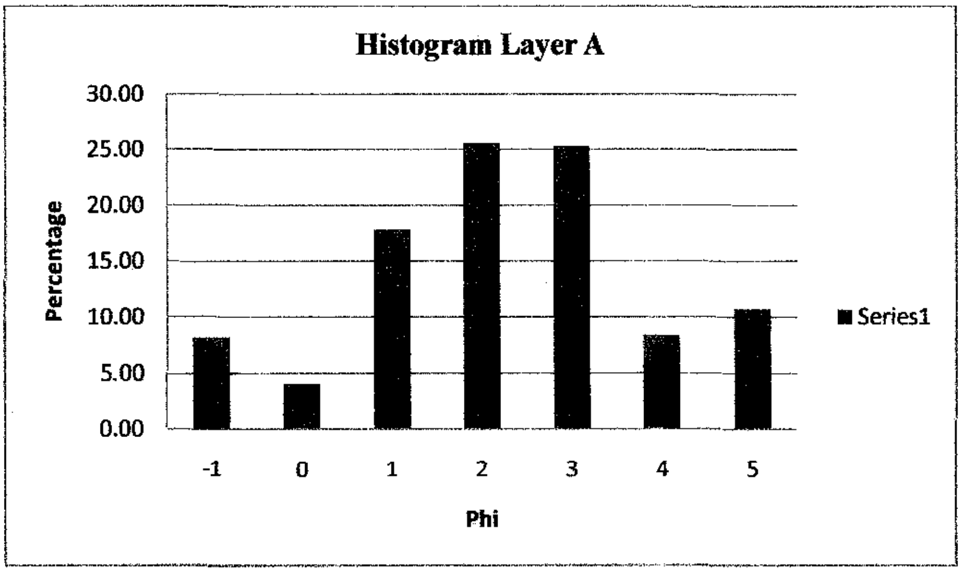

Figure 4.4 shows the percentage distribution for Facies A at Canada Hill outcrop. Phi 2 and 3 records the highest percentage of grain size. This is the example of histogram chart for medium sand.

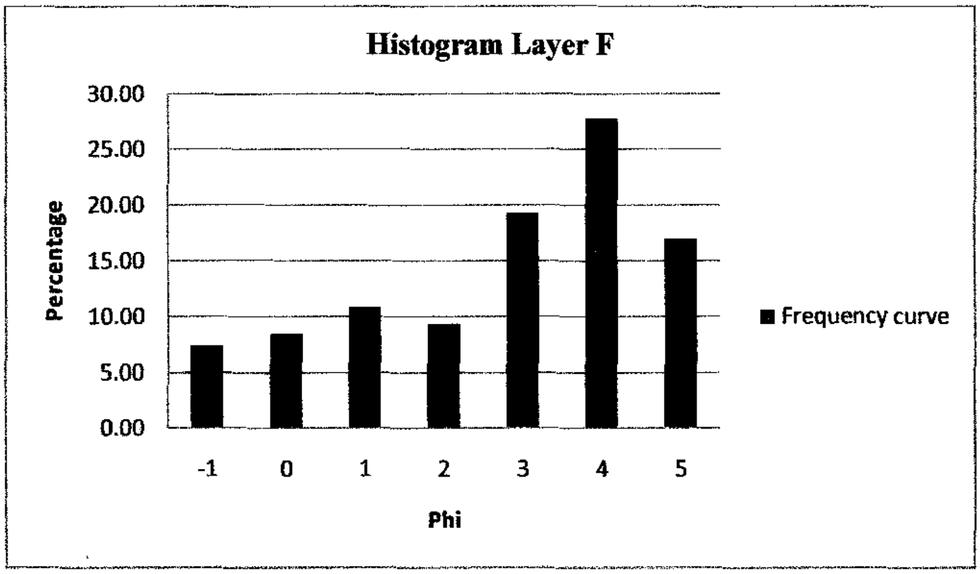

Figure 4.5 shows the percentage distribution for Facies F at Canada Hill outcrop. Phi 4 records the highest percentage of grain size. This is the example of histogram chart for fine sand.

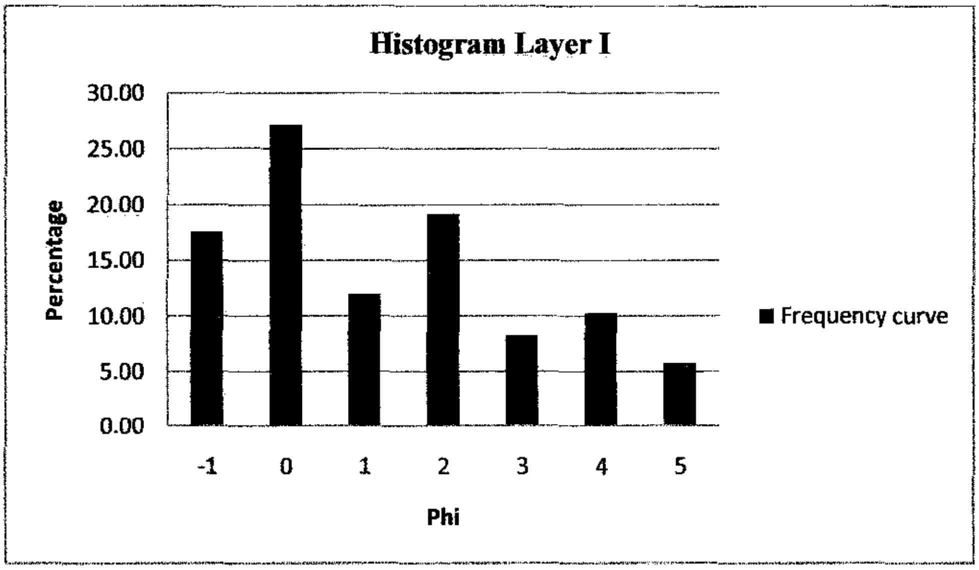

Figure 4.6 shows the percentage distribution for Facies I at Canada Hill outcrop. Phi 0 records the highest percentage of grain size. This is the example of histogram chart for coarse sand.

4.4.4.2 Sorting

Sorting or the measure of degree of scatter is the tendency for the grains to all is of one class of grain size. Sorting can be expressed by various statistical methods. The simplest of these is the measurement of the central tendency of which there are three commonly used parameters; the median, the mode, and the mean. The median grain size is that which separates 50% of the sample from other; the median is the 50 percentile. The mode is the largest class interval. The mean is variously defined, but a common formula is the average of the 25 and 75 percentile. It can be measured using Inclusive Graphic Standard Deviation (D) formula:

$$\textit{Inclusive Graphic Standard Deviation } (D) = \frac{\emptyset 84 - \emptyset 16}{4} + \frac{\emptyset 95 - \emptyset 5}{6.6}$$

The calculation for sorting at every facies is summarized at Table 4.4 below.

Facies	Characteristic	Standard Deviation (D)	Classification
A	Thinly-bedded, sand shale alternation unit	1.73	Poorly sorted
B	Laminated mudstone facies	2.03	Very poorly sorted
C	Wavy, nonparallel bedding sandstone	2.03	Very poorly sorted
D	Mud-draped sandstone	1.67	Poorly sorted
E	Massive coarse sandstone facies	1.89	Poorly sorted
F	Mudstone-dominated	1.94	Poorly sorted
G	Clean whitish sandstone.	2.23	Very poorly sorted
H	Mud-draped sandstone	1.98	Poorly sorted
I	Interbedded mud and sandstone	1.86	Poorly sorted
J	Flaser-bedded sandstone	1.88	Poorly sorted

Table 4.4 shows the classification of sorting for every facies

The grain sorting at Canada Hill outcrop mostly poor sorted. Statistically, 70% of the facies consists of poor sorted grain while 30% are very poorly sorted.

4.4.4.3 *Inclusive Graphic Skewness*

Skewness is a measure of the asymmetry of the probability distribution of a real-valued random variable. The skewness value can be positive or negative, or even undefined. Qualitatively, a negative skew indicates that the tail on the left side of the probability density function is longer than the right side and the bulk of the values (including the median) lie to the right of the mean. A positive skew indicates that the tail on the right side is longer than the left side and the bulk of the values lie to the left of the mean. The calculation for skewness is based on Folk & Ward 1957 formula. Table 4.5 summarizes the skewness calculation for every facies and the classification of graph trend line. .

$$Skewness\ (S) = \frac{\emptyset 84 + \emptyset 16 - 2(\emptyset 50)}{2(\emptyset 84 - \emptyset 16)} + \frac{\emptyset 95 + \emptyset 5 - 2(\emptyset 50)}{2(\emptyset 95 - \emptyset 5)}$$

Facies	Characteristic	Skewness (S)	Classification
A	Thinly-bedded, sand shale alternation unit	-0.05542	Near symmetrical but graphically skewed to symmetrical
B	Laminated mudstone facies	0.108258	Positive skewed, graphically skewed to the negative phi values)
C	Wavy, nonparallel bedding sandstone	-0.43111	Negative skewed, graphically skewed to the positive phi values)
D	Mud-draped sandstone	0.035159	Near symmetrical but graphically skewed to symmetrical
E	Massive coarse sandstone facies	-0.29834	Negative skewed, graphically skewed to the positive phi values)
F	Mudstone-dominated	-0.3207	Strongly Negative skewed, graphically skewed to the very positive phi values, fine)
G	Clean whitish sandstone.	-0.26681	Negative skewed, graphically skewed to the positive phi values)
H	Mud-draped sandstone	0.023202	Near symmetrical but graphically skewed to symmetrical
I	Interbedded mud and sandstone	0.28639	Positive skewed, graphically skewed to negative phi values
J	Flaser-bedded sandstone	-0.16754	Negative skewed, graphically skewed to the positive phi values)

Table 4.5 summarized the skewness data from sieving analysis

Of all the grain-size parameters of sediments, the sign of skewness is the most sensitive to environmental conditions of deposition. However, the skewness value is not co relatable with the changes in the energy of the depositing medium. It is only the sign of skewness that indicates the state and the nature of the energy of the depositional agent.

Facies B and Facies I which consists of laminated mudstone facies and interbedded mudstone facies recorded positive skewness and graphically skewed to negative phi values. Figure 4.7 shows the trend in graph which skewed towards negative values of phi. The positively skewed sediments at the downstream parts of meanders and the straighter parts of the river system pointed to a calm and steady energy environment of sedimentation.

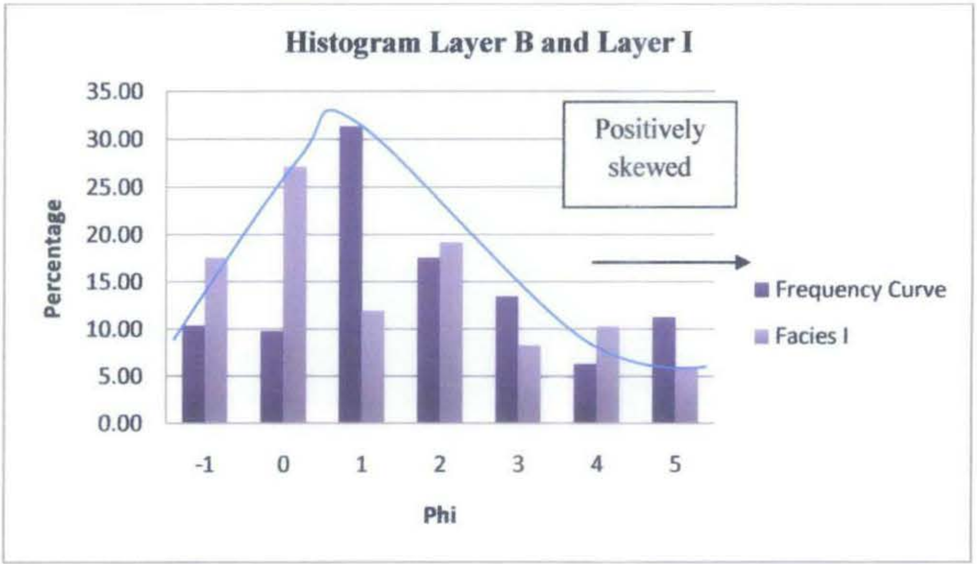

Figure 4.7 shows positive skewed graph. Positive skewed means the peaked of curved is more to negative value of Phi.

Facies C, E, G and J are mostly sandstone dominated facies. The skewness graph shows that the graph is negatively skewed. The peaked of the curve is high at positive value of mesh phi. Figure 4.8 shows the negative skewed of graph. The sediments, skewed negatively at the river confluences and the upstream parts of meanders, are indicative of turbulent energy conditions of the depositing medium.

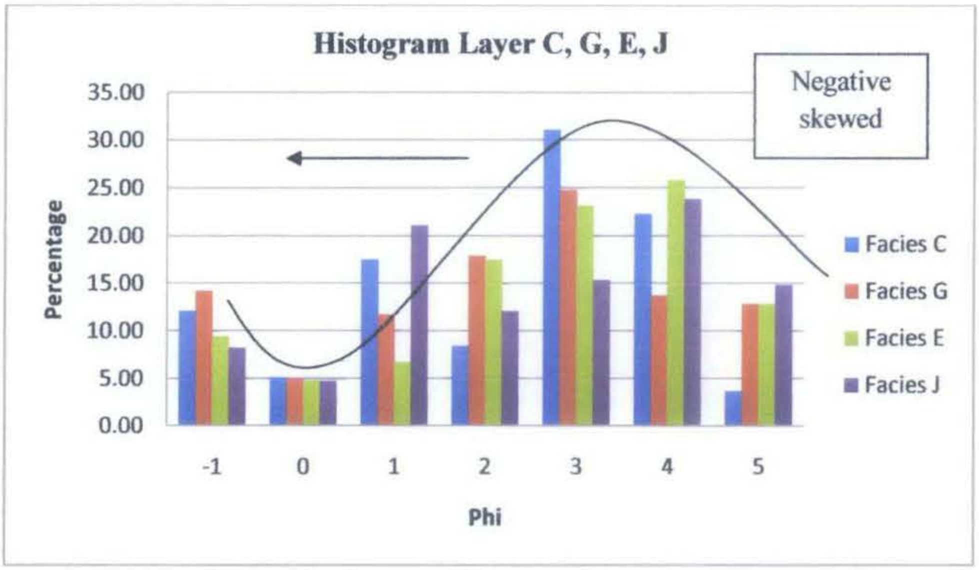

Figure 4.8 shows negative skewed graph. Negative skewed means the peaked of curved is more to positive value of Phi.

4.4.4.4 Kurtosis

Kurtosis is the degree of peakedness or departure from the "normal" frequency or cumulative curve. Leptokurtic curves are excessively peaked; center is better sorted than ends. Platykurtic curves are flat-peaked; ends are better sorted than center. Mesokurtic curves are normal; a normal bell shaped curve. The experimental result for kurtosis is summarized in Table 4.6. Graphic Kurtosis (K) formula is:

$$Graphic\ Kurtosis\ (K) = \frac{\emptyset 95 - \emptyset 5}{2.44(\emptyset 75 - \emptyset 25)}$$

Facies	Characteristic	Graphic Kurtosis (K)	Classification
A	Thinly-bedded, sand shale alternation unit	1.245502	Leptokurtic (center is better sorted than ends)
B	Laminated mudstone facies	1.27246	Leptokurtic (center is better sorted than ends)
C	Wavy, nonparallel bedding sandstone	1.15988	Leptokurtic (center is better sorted than ends)
D	Mud-draped sandstone	0.971399	Mesokurtic (normal bell shaped curve)
E	Massive coarse sandstone facies	1.170449	Leptokurtic (center is better sorted than ends)
F	Mudstone-dominated	0.844936	Platykurtic (ends are better sorted than center)
G	Clean whitish sandstone.	1.153727	Leptokurtic (center is better sorted than ends)
H	Mud-draped sandstone	0.883392	Platykurtic (ends are better sorted than center)
I	Interbedded mud and sandstone	0.851667	Platykurtic (ends are better sorted than center)
J	Flaser-bedded sandstone	0.845628	Platykurtic (ends are better sorted than center)

Table 4.6 summarizes experimental result for kurtosis

From Table 4.6, the analysis of kurtosis for facies can be divided into three groups. The first group is the leptokurtic which mostly available at the bottom part of the outcrop. Platykurtic graph is mostly found at top part of the outcrop which includes Facies H, I and J. Figure 4.9 shows the comparison between platykurtic, leptokurtic and mesokurtic.

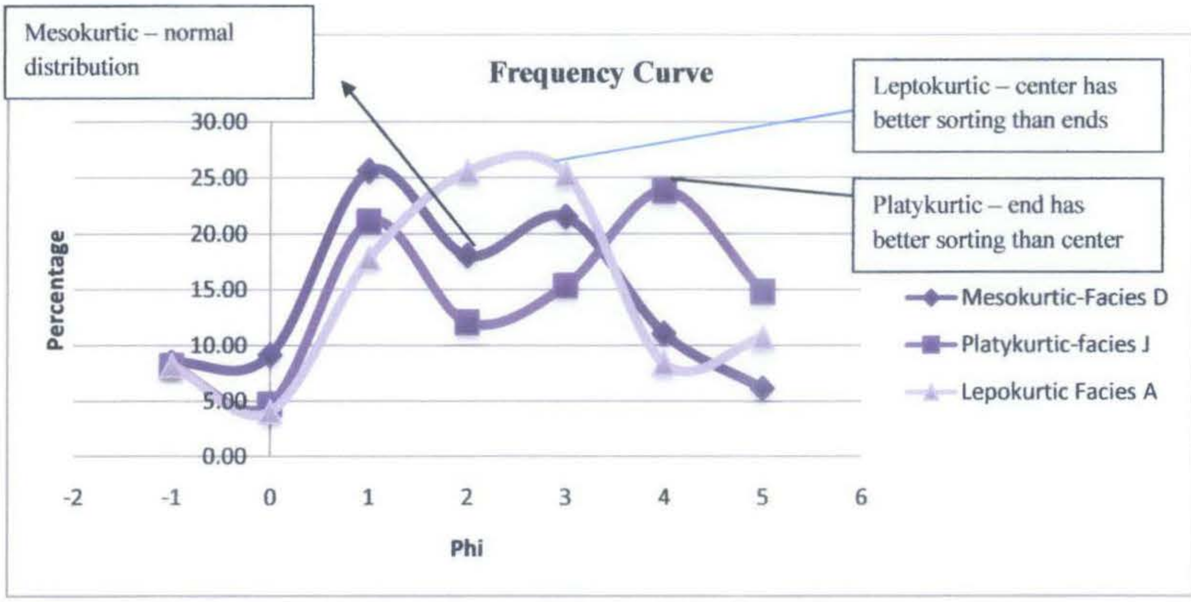

Figure 4.9 shows comparison of mesokurtic, leptokurtic and platykurtic

4.5 Porosity Determination

Porosity is determined from the analysis of samples which were done using Porosimetry. The samples were assigned to different sandstone lithofacies, A, E, G, I, J. For each lithofacies, each sample is taken and cut into small cube before being analyzed in the laboratory equipment. Porosity values for all six sandstone lithofacies generally range from 12.72 to 25.78 and show a negatively skewed distribution. Porosity distributions of the facies are shown in Table 4.7 below.

Facies	Characteristic	Porosity (%)	Classification
A	Thinly-bedded, sand shale alternation unit	21.32	Near symmetrical but graphically skewed to symmetrical
E	Massive coarse sandstone facies	20.66	Negative skewed, graphically skewed to the positive phi values)
G	Clean whitish sandstone.	25.78	Negative skewed, graphically skewed to the positive phi values)
I	Interbedded mud and sandstone	12.72	Positive skewed, graphically skewed to negative phi values
J	Flaser-bedded sandstone	22.51	Negative skewed, graphically skewed to the positive phi values)

Table 4.7 shows porosity data distribution

Facies G records the highest value of porosity which is 25.78. The average porosity of the litho facies is 21.99 percent. Only Facies G and J have the porosity above the average while the lowest porosity is 19.72 percent, for facies I. Facies with mud and shale presence record quite low porosity value.

4.6 Permeability Distribution

Samples from Facies A, E, G, I, J are selected again for permeability determination. Permeability determination is conducted using Porosimetry. The experimental results for five samples are shown in Table 4.8.

Facies	Characteristic	Permeability mD
A	Thinly-bedded, sand shale alternation unit	121
E	Massive coarse sandstone facies	863
G	Clean whitish sandstone.	643
I	Interbedded mud and sandstone	5.09
J	Flaser-bedded sandstone	73.83

Table 4.8 Permeability determinations for Facies A, E, G, I and J

Table 4.8 shows that Facies E which is massive coarse sandstone facies records the highest permeability. The range of permeability is from 5.09 milidarcies to 863 mD. Interbedded mud and sandstone has low permeability (5.09 mD) due to effect of mud which might be the flow barrier in this layer.

CHAPTER 5
DISCUSSION

5.1 Introduction

This chapter discusses the results from field and laboratory analysis. It also summarizes the data for all facies, their porosity and permeability relationships, the existence of permeability barriers and the quality of sandstone reservoirs. In this project, the final outcome is to determine which facies is the best sandstone layer and to provide justification on the factors which enables the sandstone layers to be effective. Special features and unique physical textures of the rock also highlighted in this part as a reference and classification of heterogeneity. This chapter also discusses the uncertainties and limitations encountered throughout this project. A proper reservoir characterization is important to decipher the effects of heterogeneity on reservoir performance due to primary, secondary, and/or enhanced oil recovery operations. As permeability is the most important flow property, an accurate reservoir characterization requires accurate permeability description as a function of space. Reservoir efficiency of producing hydrocarbons is largely controlled by internal reservoir internal reservoir architecture and geological setting of reservoir. Therefore, we draw a conclusion that the study of reservoir performance should not neglect the characteristics of reservoir by merging geology study and engineering aspect.

5.2 Summary of Experimental Results

Table 5A (See Appendices Chapter 5) shows the summary of experimental results for all facies in Canada Hill outcrop. This table includes number of facies identified, description of every facies, close up image of every facies, thickness and uniformity, lateral continuity, sieving analysis data – grain size, sorting, skewness and kurtosis, porosity, permeability and presence of special features such as mud drapes, bedding and mud laminae.

5.3 Porosity and Permeability Relationship

Permeability is a fundamental property of rocks for the managing of geothermal reservoirs as well as for the understanding of geological processes involving fluid flow. According to the Kozeny-Carman equation, permeability is related to porosity, tortuosity and the hydraulic effective pore radius, which represent different aspects of pore space geometry. Permeability can be related to porosity on condition that an adequate pore space model is applied which reflects the diagenetic rock type.

In the earth, rocks and their pore space evolve according to various geological processes (e.g., compaction during burial, depressurization and cooling during uplift, diagenesis and metamorphic reactions, deformation under tectonic stresses). Some of these processes produce pores and others destroy them; all change permeability. Thus, each process defines a specific evolution permeability-porosity relationship. The permeability-porosity relationship by means of cross-plots was studied for various rocks types. Figure 5.1 shows the relationship between porosity and permeability. Facies E and Facies G are identified as good sandstone, high porosity and high permeability.

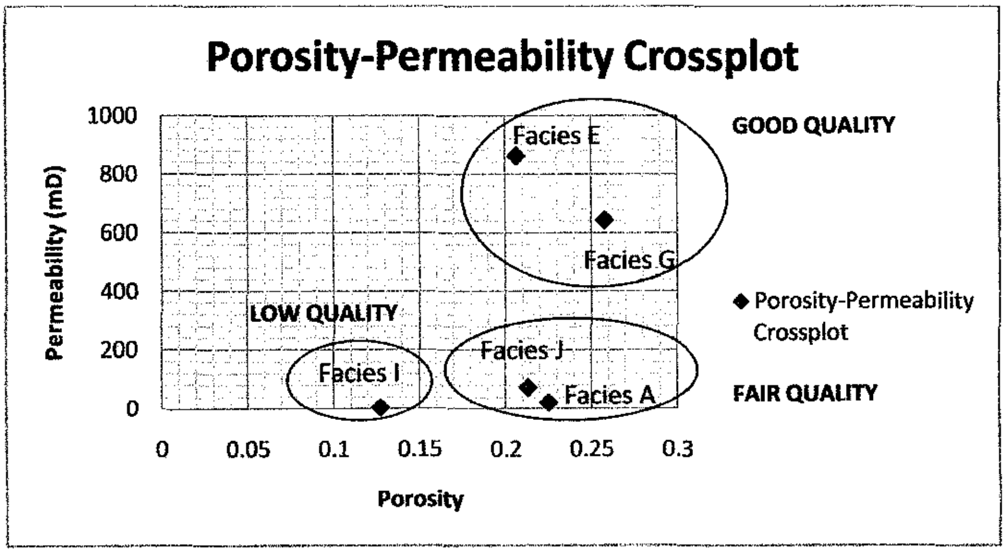

Figure 5.1 Porosity and permeability cross plot. Facies E and Facies G shows high porosity and permeability.

5.4 *Bioturbation*

The action of bioturbation can be classified in terms of sediment mixing, sediment cleaning, sediment packing, and pipe-work-building strategies. Bioturbation has the potential to (1) increase isotropy or uniformity of grain size by destroying sedimentary laminae through burrow homogenization, or (2) decrease isotropy by selectively sorting grains into burrow lining and fill by grain size, and through creation of open-burrow systems filled with later sediments of differing character to the host sediment (Tonkin N.S, 2009). The petrophysical characteristics of the reservoir facies are highly dependent on trace fossil morphology, presence or absence of burrow linings, nature of burrow fills, burrow size, and bioturbation intensity. Mudstone-rich facies and ichnofabrics containing mudstone-filled and/or lined burrows (e.g., *Ophiomorpha* and clusters of *Chondrites*) have the net effect of permeability reduction. In contrast, permeability enhancement is documented from muddy sandstone facies with clean sand-filled burrows (e.g., *Thalassinoides*) and clean sandstones with burrow-mottled or diffuse to massive textures.

The presence of bioturbation was recorded at Facies A. Figure 5.2 shows the close up image of bioturbation on Facies A.

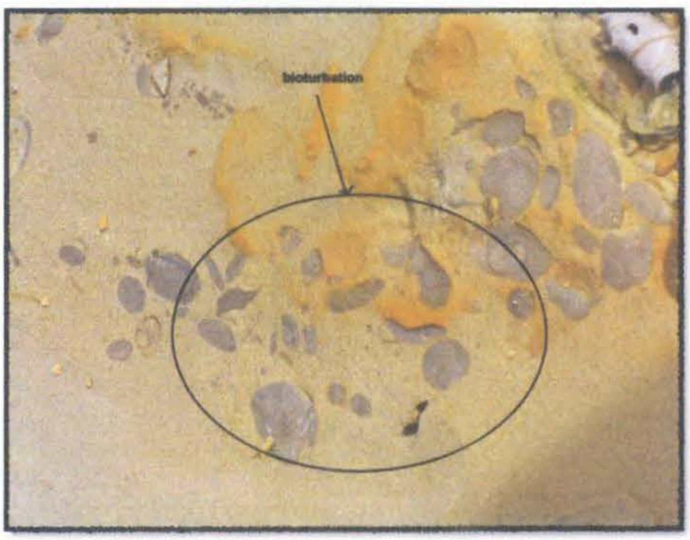

Figure 5.2 shows bioturbation at Facies A

The permeability of Facies A is very low compared to other facies. Bioturbation is one of the main factors that may cause permeability reduction.

5.5 Sandstone Volume and Shale Permeability Barriers

Facies I is a composite facies comprising interbedding of sandstone (10 to 15 cm thickness) and mud layers (5 to 7 cm thickness). The heterogeneity in facies I reduced the volume of sandstone and will eventually reduce the Net to Gross thickness ratio. Mud layer is non porous and non permeable rock. Therefore, the presence of mud layer reduces the volume of sandstone. Mud layers clearly transform the layers into permeability barriers. In Facies I, the direction of mud layers is horizontal.

Figure 5.3 shows the interbedded sand and mud at facies I. (The scale of the image is 1cm: 0.5 cm)

5.6 Effect of laminations on permeability

Facies A is parallel laminated sandstone. The lamination may be completed, clean, or having lines with mud and carbonaceous material. The poro-perm relationship of Facies A shows that Facies A is a fair quality sandstone reservoir, its porosity is 21.32 % and its permeability is 121 mD. These low reading may be due to the presence of mud and carbonaceous lamination in this facies. Figure 5.4 shows the laminations recorded in Facies A.

Figure 5.4 shows the lamination of mud in sandstone layer at Facies A

5.7 Net and Gross Thickness of sandstone resrvoirs

Gross sand is the thickness of the sand top to bottom. Net sand is the number of meters in this sand which has porosity. In this case, the net sand is the sandstone layer which contains no mud or shale because mud and shale are non porous rock and non permeable rock. Therefore, the comparison between net and gross sand thickness is made by calculating thickness of sandstone reservoir. Shaly sandstone, although might have porosity, is negligible because it has no significance in reservoir storage capacity. Table 5.1 shows the gross and net thickness of the outcrop.

Facies	Characteristic	Average Thickness (m)	Gross Thickness	Net Thickness
A	Thinly-bedded, sand shale alternation unit	0.35	0.35	0.35
B	Laminated mudstone facies	0.27	0.27	
C	Wavy, nonparallel bedding sandstone	1.20	1.20	1.20
D	Mud-draped sandstone	1.14	1.14	1.14
E	Massive coarse sandstone facies	1.90	1.90	1.90
F	Mudstone-dominated	0.88	0.88	
G	Clean whitish sandstone.	1.71	1.71	1.71
H	Mud-draped sandstone	2.43	2.43	
I	Interbedded mud and sandstone	2.07	2.07	1.55 (interbedded)
J	Flaser-bedded sandstone	0.39	0.39	0.39
Total thickness			12.34	8.24

Table 5.1 shows the comparison between gross thickness and net thickness

The gross thickness is 12.34 meters and net thickness is 8.24 meters. The net thickness (which has effective porosity) is only 67.58% of the total thickness in this outcrop.

5.8 Classification of the quality of facies

The facies can be grouped into three main classes; high quality, fair quality, and low quality sandstone reservoir. High quality reservoir refer to facies that records high porosity and permeability (permeability value is more than 500 mD). Fair quality reservoir refers to facies that records fair and medium porosity and permeability while low quality reservoir refers to facies with low porosity and permeability. Table 5.1 shows the classification of facies.

Classification	Facies
High quality	Facies E and G
Fair quality	Facies A and J
Low quality	Facies I

Table 5.2 shows the classification of facies into high, fair and low quality

Facies E and G are high quality sandstone reservoirs. Facies E, a massive coarse sandstone facies record high porosity and permeability, its porosity is 20.66% and its permeability is 863 mD. It also has good thickness which is 202 meters and its lateral continuity is 25 meters. It is a find sand and poorly sorted with no internal structures found in this rock which may act as permeability barriers. Facies G, a clean whitish sandstone, recorded the highest porosity of 25.78% and permeability of 643 mD. It has good thickness of 171 meters and lateral continuity of 25 meters. Facies G display medium sand and very poorly sorted type of sandstone. No permeability barriers is found in this facies.

Facies A, a thinly bedded sand shale unit is classified as fair quality reservoir. Its porosity is 21.32% but the permeability is low; its permeability is 121 mD. The thickness of this facies also low; its thickness is 35 cm. The presence of permeability barriers such as mud and carbonaceous material lamination may reduce the permeability of this facies. Facies J, a flaser bedded sandstone recorded a porosity of 22.515 and its permeability is 73.83 mD. It is a fine sand and poorly sorted and the thickness is very low; only 39 cm.

Facies I, an interbedded sandstone and mud layers is a low quality reservoir. Its porosity is 12.72 % and the permeability is 5.09 mD. The presence of mud layers reduces the volume of sandstone and net to gross ratio. Moreover, it is a coarse sand and poorly sorted. Although it possess good thickness, the mud layers which consists of 50% of the thickness, reduce the volume of this facies and may act as permeability barriers.

5.9 Uncertainties and Limitations

1. **Time**

   Due to the shortened period of research, most of experimental work cannot be done. Although more sample should be examined for each layer, only one sample can be tested which might reduce the accuracy of each data.

2. **Experimental error**

   This experimental error mostly occurs in sieving analysis. The time for shaking the samples in sieve should be increase to get better results. However, the time set only about 10-15 minutes.

3. **Sample selections**

   To get better overview of result, sample selections should be made at various locations or sections to examine the distribution of heterogeneities in the outcrop. If possible, the samples should be selected as many as possible at different locations.

CHAPTER 6
CONCLUSION AND RECOMMENDATION

6.1 Recommendation

Although the project has been completed successfully, there is still a room for improvement in future. The aspect that needs to improve in future includes the process of selecting the sample, fieldwork and experimental work and any additional data or methodology that can improve the project outcome. These are the recommendations that can be applied in the future.

1. Increasing the number of samples selected at every layer

   More samples will increase the accuracy of the output. The samples need to be taken at various locations to understand the pattern of porosity and permeability of rock at different places.

2. Repetition of experiment procedure

   Repetition of experimental procedure should be done to improve the accuracy of data especially for sieving analysis. Average result can be taken from the repetitive of experiment conducted.

3. Visual aid

   Photograph is the main medium in identifying the characteristics of the reservoir. Clear image and better resolution of pictures help to identify small features and structures of outcrop. The location should be marked by any object to ease the process of scaling the picture.

Other petrophysical properties such as density, velocity, fluid saturation also can be conducted in future to have larger range of petrophysical characteristics of rock.

6.2 Conclusion

The main objective of the project is to characterize and quantify the Miri reservoirs by integrating the geology information and petrophysical properties by studying and documenting the relationship between the geology information (facies characteristics, sedimentary structure and lithology) and petrophysical properties (porosity, permeability) in order to characterize the reservoir and understand the heterogeneity of formation. After characterizing the outcrop, the final outcome of the project is summarized below.

1. Facies E and G are high quality sandstone reservoirs. Facies E, a massive coarse sandstone facies record high porosity and permeability, its porosity is 20.66% and its permeability is 863 mD. It also has good thickness which is 202 meters and its lateral continuity is 25 meters. It is a find sand and poorly sorted with no internal structures found in this rock which may act as permeability barriers. Facies G, a clean whitish sandstone, recorded the highest porosity of 25.78% and permeability of 643 mD. It has good thickness of 171 meters and lateral continuity of 25 meters. Facies G display medium sand and very poorly sorted type of sandstone. No permeability barriers is found in this facies.
2. Facies A, a thinly bedded sand shale unit is classified as fair quality reservoir. Its porosity is 21.32% but the permeability is low; its permeability is 121 mD. The thickness of this facies also low; its thickness is 35 cm. The presence of permeability barriers such as mud and carbonaceous material lamination may reduce the permeability of this facies. Facies J, a flaser bedded sandstone recorded a porosity of 22.515 and its permeability is 73.83 mD. It is a fine sand and poorly sorted and the thickness is very low; only 39 cm.
3. Facies I, an interbedded sandstone and mud layers is a low quality reservoir. Its porosity is 12.72 % and the permeability is 5.09 mD. The presence of mud layers reduces the volume of sandstone and net to gross ratio. Moreover, it is a coarse sand and poorly sorted. Although it possess good thickness, the mud layers which consists of 50% of the thickness, reduce the volume of this facies and may act as permeability barriers.

4. Many permeability barriers such as laminations, bedding and bioturbation have significant impact on permeability and porosity. It is observed that layers with flow barriers have low permeability and porosity such as Facies I and D.

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APPENDICES

CHAPTER 3

METHODOLOGY

Figure 3A Measurement of thickness using measurement tape

Figure 3B Porosimeter to determine porosity and permeability

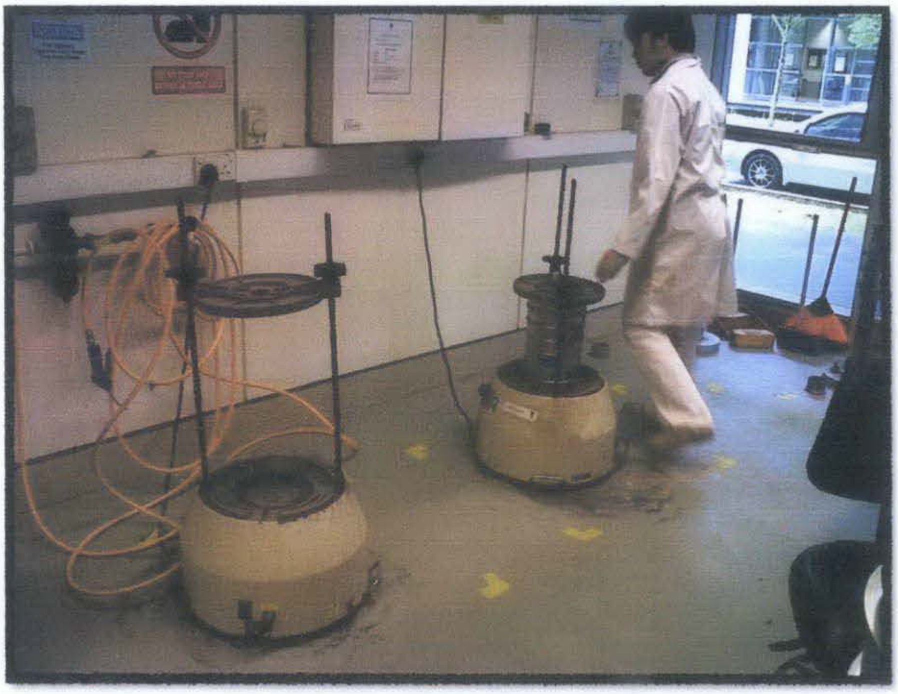

Figure 3C Sieving analysis with sieve shaker

Figure 3D Product of sieving from coarse sand to fine sand

APPENDICES

CHAPTER 4 RESULT

LAYER A

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	389.97	380.94	9.03	9.03	8.21	8.01
1	0	355.76	351.32	4.44	13.47	4.04	12.25
0.5	1	316.29	296.69	19.6	33.07	17.82	30.07
0.25	2	304.33	276.22	28.11	61.18	25.55	55.62
0.125	3	365.13	337.3	27.83	89.01	25.30	80.92
0.0625	4	270.98	261.76	9.22	98.23	8.38	89.3
pan	5	400.84	389.06	11.78	110.01	10.71	100
			TOTAL	**110.01**			

LAYER B

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	392.3	380.91	11.39	11.39	10.36	10.36
1	0	362.1	351.36	10.74	22.13	9.77	20.13
0.5	1	331.1	296.65	34.45	56.58	31.32	51.45
0.25	2	295.52	276.22	19.3	75.88	17.55	69
0.125	3	352.1	337.31	14.79	90.67	13.45	82.45
0.0625	4	268.67	261.74	6.93	97.6	6.30	88.75
pan	5	401.44	389.06	12.38	109.98	11.26	100
			TOTAL	**109.98**			

LAYER C

Screen Opening mm	phi	Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
2	-1	394.2	380.91	13.29	13.29	12.10	12.1
1	0	356.96	351.36	5.6	18.89	5.10	17.2
0.5	1	315.85	296.65	19.2	38.09	17.48	34.68
0.25	2	285.42	276.22	9.2	47.29	8.37	43.05
0.125	3	371.41	337.31	34.1	81.39	31.04	74.09
0.0625	4	286.19	261.74	24.45	105.84	22.26	96.35
pan	5	393.08	389.06	4.02	109.86	3.66	100
			TOTAL	**109.86**			

LAYER D

Screen Opening mm	phi	Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
2	-1	390.25	380.91	9.34	9.34	8.49	8.49
1	0	361.42	351.36	10.06	19.4	9.15	17.64
0.5	1	324.82	296.65	28.17	47.57	25.61	43.25
0.25	2	296.08	276.22	19.86	67.43	18.06	61.31
0.125	3	360.96	337.31	23.65	91.08	21.50	82.81
0.0625	4	273.89	261.74	12.15	103.23	11.05	93.86
pan	5	395.81	389.06	6.75	109.98	6.14	100
			TOTAL	**109.98**			

LAYER E

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	391.25	380.91	10.34	10.34	9.40	9.4
1	0	356.59	351.36	5.23	15.57	4.75	14.15
0.5	1	303.98	296.65	7.33	22.9	6.66	20.81
0.25	2	295.43	276.22	19.21	42.11	17.46	38.27
0.125	3	362.76	337.31	25.45	67.56	23.14	61.41
0.0625	4	290.08	261.74	28.34	95.9	25.76	87.17
pan	5	403.16	389.06	14.1	110	12.82	100
			TOTAL	**110**			

LAYER F

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	389.03	380.91	8.12	8.12	7.38	7.38
1	0	360.64	351.36	9.28	17.4	8.44	15.82
0.5	1	308.55	296.65	11.9	29.3	10.82	26.64
0.25	2	286.49	276.22	10.27	39.57	9.34	35.98
0.125	3	358.54	337.31	21.23	60.8	19.30	55.28
0.0625	4	292.26	261.74	30.52	91.32	27.75	81.03
pan	5	407.73	389.06	18.67	109.99	16.97	100
			TOTAL	**109.99**			

LAYER G

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	396.52	380.91	15.61	15.61	14.20	14.2
1	0	356.81	351.36	5.45	21.06	4.96	19.16
0.5	1	309.54	296.65	12.89	33.95	11.72	30.88
0.25	2	295.87	276.22	19.65	53.6	17.87	48.75
0.125	3	364.48	337.31	27.17	80.77	24.71	73.46
0.0625	4	276.83	261.74	15.09	95.86	13.72	87.18
pan	5	403.15	389.06	14.09	109.95	12.81	100
			TOTAL	109.95			

LAYER H

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	394.37	380.91	13.46	13.46	12.24	12.24
1	0	366.23	351.36	14.87	28.33	13.52	25.76
0.5	1	315	296.65	18.35	46.68	16.68	42.44
0.25	2	297.31	276.22	21.09	67.77	19.17	61.61
0.125	3	356.09	337.31	18.78	86.55	17.07	78.68
0.0625	4	272.76	261.74	11.02	97.57	10.02	88.7
pan	5	401.49	389.06	12.43	110	11.30	100
			TOTAL	110			

LAYER I

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	400.21	380.91	19.3	19.3	17.55	17.55
1	0	381.18	351.36	29.82	49.12	27.11	44.66
0.5	1	309.76	296.65	13.11	62.23	11.92	56.58
0.25	2	297.3	276.22	21.08	83.31	19.16	75.74
0.125	3	346.4	337.31	9.09	92.4	8.26	84
0.0625	4	273.01	261.74	11.27	103.67	10.25	94.25
pan	5	395.39	389.06	6.33	110	5.75	100
			TOTAL	110			

LAYER J

Screen Opening		Weight of Sieve with sands (gram)	Weight of empty sieve (gram)	Weight of sand (grams)	Cumulative Weight	Weight Percent	Cumulative Weight Percent
mm	phi						
2	-1	389.92	380.91	9.01	9.01	8.19	8.19
1	0	356.54	351.36	5.18	14.19	4.71	12.9
0.5	1	319.83	296.65	23.18	37.37	21.07	33.97
0.25	2	289.48	276.22	13.26	50.63	12.06	46.03
0.125	3	354.19	337.31	16.88	67.51	15.35	61.38
0.0625	4	287.93	261.74	26.19	93.7	23.81	85.19
pan	5	405.35	389.06	16.29	109.99	14.81	100
			TOTAL	109.99			

Table 4(A)-4(J) Result from sieving for every facies/layers

APPENDICES
CHAPTER 5

	Heterogeneity Type		**Scale of Heterogeneity**		**Sedimentary Texture**				**Petrophysical Properties**	
	Description	**Geology Features**	**Thickness m**	**Lateral Continuity (m)**	**Grain Size**	**Sorting**	**Skewness**	**Kurtosis**	**Porosity %**	**Permeability mD**
A	Thinly-bedded, sand shale alternation unit. Yellowish in color.	Shale lamination and bioturbation	Uniform 0.35	15-20 m	1.787 (Medium sand)	1.73 (Poorly sorted)	-0.05542 Near symmetrical but graphically skewed to symmetrical	1.245502 Leptokurtic (center is better sorted than ends)	21.32	121
B	Laminated mudstone facies. Background mud stone is dark grey or grayish black.	Very fine sand to silty laminations of 15 centimeters thickness.	Uniform 0.27	10 m	1.813 (Medium sand)	2.03 (Very poorly sorted)	0.108258 (Positive skewed, graphically skewed to the negative phi values)	1.27246 Leptokurtic (center is better sorted than ends)		
C	Small grain size, hard texture with lamination of grayish and yellowish sandstone.	Wavy, nonparallel bedding sandstone. Simple cross bedded type of bedding with cross-beds features.	Uniform 1.20	20-25 m	1.813 (medium sand)	2.03 (very poorly sorted)	Negative skewed, graphically skewed to the positive phi values	Leptokurtic (center is better sorted than ends		

D	mud-draped sandstone	sandstone is coated with thin, black mud drapes	Non-Uniform 1.10-1.18	25-30 m	1.433 Medium sand	1.67 Poorly sorted	Near symmetrical but graphically skewed to symmetrical	Mesokurtic (normal bell shaped curve		
E	massive coarse sandstone facies	poorly sorted, medium to coarse grained sandstone with no internal structures	Non-Uniform 1.89-2.02	25-30 m	2.223 Fine sand	1.89 Poorly sorted	Negative skewed, graphically skewed to the positive phi values)	Leptokurtic (center is better sorted than ends)	20.66	863
F	mudstone-dominated facies	mud stone lithologies with up to 50% sandstone intercalations and is generally non reservoir	Non-Uniform 0.85-0.91	20 m	2.30 Fine sand	1.94 Poorly sorted	Strongly Negative skewed, graphically skewed to the very positive phi values, fine)	Platykurtic (ends are better sorted than center)		
G	clean whitish sandstone.	small bedding which is not obvious can be seen at this facies	Uniform 1.71	25 m	1.727 Medium sand	2.23 Very poorly sorted	Negative skewed, graphically skewed to the positive phi values)	Leptokurtic (center is better sorted than ends)	25.78	643

H	mud-draped sandstone	mud drape is thicker than Facies D	Uniform 2.43	20-30 m	1.402 Medium sand	1.98 Poorly sorted	Near symmetrical but graphically skewed to symmetrical	Platykurtic (ends are better sorted than center)		
I	interbedded mud and sandstone	The bedding type is fining upwards and non erosional bounding surfaces	Uniform 2.07	25 m	0.797 Coarse sand	1.86 Poorly sorted	Positive skewed, graphically skewed to negative phi values	Platykurtic (ends are better sorted than center)	12.72	5.09
J	flaser-bedded sandstone	single horizon of flasered bed occurs as the top part of heterogeneous sandstone.	Uniform 0.39	15-20 m	2.12 Fine sand	1.88 Poorly sorted	Negative skewed, graphically skewed to the positive phi values)	Negative skewed, graphically skewed to the positive phi values)	22.51	73.83

Table 5A Summary of heterogeneities in Canada Hill Outcrop