THE STUDY OF THE DRILLING BIT IN DRILLING OPERATION

By

MUHAMAD FIRDAUS BIN BIDI

FINAL PROJECT REPORT

Submitted to the Mechanical Engineering Programme
in Partial Fulfillment of the Requirements
for the Degree
Bachelor of Engineering (Hons)
(Mechanical Engineering)

Universiti Teknologi Petronas
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

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Dr. Sonny Irawan
Senior Lecturer
Geoscience & Petroleum Engineering Department
Universiti Teknologi PETRONAS
Bandar Seri Iskandar, 31750 Tronoh
Perak Darul Ridzuan, MALAYSIA

Dr Sonny Irawan
Project Supervisor

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

December 2007

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.

M. Firdaus

Muhamad Firdaus Bin Bidi

ABSTRACT

The project study is based on the drilling performance in Baram G108 (well name) at Baram Field in Sarawak basin. The main objectives are to determine the ROP of the cutting element into the formation, to determine the bit damage during drilling operation, and to define the drilling cost in Baram G108. The study of the drilling bit is only focused on the Polycrystalline Diamond Compact (PDC). This bit gives a good rate of penetration (ROP) as well as longer bit life. Other than that, the drilling efficiency is fully optimized by applying it into the operation. In this project analysis, the performances of the bit are represented in the graph analysis which including a number of parameters like bit hours, ROP, RPM, and the footage drilled where every interpretation can be made. The output of the project is expected to be achieved where all the stated objectives are met and the drilling efficiency can be further optimized.

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Special thanks to the people who have given me the opportunity to help making the project to this level, especially to the project supervisor, Dr Sonny Irawan and project coordinator, Dr Khairul Fuad who have willingly spared their time and knowledge to help and guide me throughout this project progress. I also would like to convey my appreciation to the colleagues who has given me the supports and helps when I am in need. My final note of gratitude goes to everyone who has directly and indirectly contributed to the project, thus helped making this project possible to be completed to this level.

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CHAPTER 1
INTRODUCTION

1.1 Background of Study

Petroleum exploration activities in all around the world are quite active lately due to the demands on the hydrocarbons in various industry and personal usage purposes. The production of crude oil and gas reached hundred thousand barrels and sometimes reach millions for every 24 hours.

The project study is taking place in Baram G108 (well name) at Baram Field which is located in Sarawak basin in Malaysia. There are a lot of exploration, production as well as the development of the field has taken place in order to gain the better amount of the crude oil and gas. Here, the project study is based on the bit that being used by PETRONAS in verifying the performance efficiency during runs.

The study of the drilling bit in this project is only focused on the Polycrystalline Diamond Compact (PDC). This bit gives a good rate of penetration (ROP) as well as longer bit life [7]. Other than that, the drilling efficiency is fully optimized by applying it into the operation. In this project analysis, the performances of the bit are represented in the graph analysis where every interpretation can be made which cover a number of parameters like bit hours, ROP, RPM, and the footage drilled.

1.2 Problem Statement

In the current situation of the petroleum production system, the problem to the bit cutter (tear and wear) still needs some improvement so that the bit life can be optimized. Even many petroleum companies had proposed and used the Polycrystalline Diamond Compact (PDC) bit which can withstand the high torque and abrasiveness, but the problem is still there. This may due to the inefficiency of the few factors that will be discussed later.

1.3 Objective of Study

- To determine the penetration (ROP) of the cutting element into the formation.
- To determine the bit damage during drilling operation.
- To define the drilling cost in Baram G108.

1.4 Scope of Study

[1] The collection of the Literature Review and the Drilling Record Sheet (DRS).

[2] The needed parameters are extracted from DRS (contains bit hours, ROP, RPM, and footage drilled).

[3] The construction of the performance graph;

a.) RPM versus Bit Hours and Footage Drilled versus RPM.

b.) ROP versus Min. RPM and ROP versus Max. RPM.

c.) Mean Depth versus Drilling Cost.

[3] The data interpretation is being carried out.

CHAPTER 2
LITERATURE REVIEW

The review for the study was taken abundantly from journals and the internet. In this section, there are a number of literature reviews that has been put into the discussion so that the understanding on the project study can be acknowledged perfectly. Here are some notes taken for the study;

2.1 PDC Failure Mechanisms

Polycrystalline Diamond Compact (PDC) have gained wide commercial acceptance in oil and gas drilling due to their high rates of penetration (ROP), long life and mechanical simplicity. However, PDC bits have limited success at drilling high compressive strength and abrasive rock formation.[7]

The PDC bit uses a small disc of synthetic diamond that act as a cutter to fail the rock in the formation. The penetration technique that applied in PDC bit is through shearing and grinding action. In relative plastic, sedimentary rocks as shale, limestone, and weakly cemented sandstones the shearing action is the most efficient cutting mechanism by requiring less energy to drill compared to other bit type like rock bit, natural diamond, and fish tail.[7]

The use of PDC drag-cutting drill bits has become common practice in the oil and gas drilling industry over the last three decades. In soft and medium hard formations, these bits exhibit at least twice the penetration rate of a traditional roller bit. Currently,PDC drill bits hold records for drilling rate, footage drilled in a single run, and net durability. These advantages in drilling performance over rotary bits can easily result in drilling savings of up to $100,000 for a single bit run, and has generated a market for these bits in excess of $200 million per year.[7]

One significant disadvantage of PDC bits is the high principal cost of the individual PDC cutters. Production of traditional PDC cutters requires multiple, ultra-high-pressure hot pressing steps carried out at 1600-1800°C and 6-7 GPa. These pressures and temperatures are only attainable in anvil style hot presses used for diamond synthesis. This places severe limitations on the production volume and the cycle rate of the production apparatus. Small sample volumes, long cycle times, and the steeply exponential nature of the cost/processing pressure relationship cumulatively result in individual cutter costs in excess of $100.[7]

When these bits are used to drill hard formations in ultra-deep, hot holes, the drilling rate and lifetime of commercially available PDC bits are dramatically reduced. Failure in individual PDC cutters is due principally to increased impact loading and the higher drilling temperatures associated with an increased wear flat between the bit and the hard rock surface being cut. Above 350°C, the tungsten carbide-cobalt (WC/Co) backing disk softens to the same relative hardness as quartz particles in the drilling surface. This causes a dramatic increase in abrasive wear in the backing disk which, in conjunction with the increased impact loading, reduces or eliminates the self-sharpening effect of the cutter. These same temperature conditions also cause large tensile stresses in the diamond overlay due to thermal expansion mismatch between the WC/Co backing disk and the overlay material. Differential thermal expansion of the entire cutter also causes compressive stresses in the wear-flat region of the WC/Co backing disk that can surpass the compressive strength of the material. These effects accelerate with increasing temperature up to the stability limit of the diamond face at 750°C.[9]

The poor temperature stability of traditional PDC cutters has been partly addressed with the current generation of TSP cutters which are stable up to 1200°C and show decreased wear above 350°C. However, this additional thermal stability comes at the price of reduced fracture toughness in the diamond overlay as a result of using silica binding phase instead of the cobalt that is used in traditional PDC cutters. Furthermore, the TSP overlay is difficult to attach to the WC/Co backing disk, requiring preferential heating of the overlay to avoid a disadvantageous residual stress profile in the attached cutter.[9]

2.2 Rock Hardness

Rock hardness is a term used in geology to denote the cohesiveness of a rock and is usually expressed as its compressive fracture strength. Terms such as hard rock and soft rock are used by geologists to distinguishing between igneous/metamorphic and sedimentary rocks, respectively. These terms originated from historical mining terms, reflecting the methods needed to economically mine an ore deposit. For example, a hard rock needs to be mined with explosives and a soft rock can be mined with hand tools, such as pick and shove.[1]

Rocks can be tested for their unconfined fracture strength by using ASTM standard tests. These involve loading a small rock core at a rate of 0.7 MPa/s until it fails brittlely. The fracture strength is given as the maximum stress necessary to induce failure of the rock core. This value gives an indication of the cohesiveness and density of a rock. As seen in Table 1 igneous, metamorphic and sedimentary rocks can be classified from very weak to very strong with regards to their unconfined fracture strengths (Attewell & Farmer 1976). Generally, sedimentary rocks can range from weak to medium (10-80 MPa), and igneous rocks range from medium to very strong (40-320 MPa). The highest unconfined compressive strength observed in a rock is on the order of 400 MPa (e.g. nephritic jade).[8]

Table 1 The classification of rock hardness (from Attewell & Farmer 1976)

Strength Classification	Strength Range (Mpa)	Typical Rock Types
Very weak	10-20	Weathered and weakly-compacted sedimentary rocks
Weak	20-40	Weakly-cemented sedimentary rocks
Medium	40-80	Competent sedimentary rocks; some low density coarse grained igneous rocks
Strong	80-160	Competent igneous rock; some metamorphic rocks and fine-grained sandstones
Very strong	160-320	Quartzites; dense fine-grained igneous rocks

Table 2 presents the typical unconfined compressive, tensile, and shear strengths for a variety of rock types (Attewell & Farmer 1976). It can be seen that each rock type can exhibit considerable variation. These variations are the result of a number of factors, which include porosity, grain size, grain shape, grain and crystallographic preferred orientation, mineralogy, and moisture content. In most rocks the main factors controlling rock hardness are porosity, grain size, and grain shape. All three of these factors affect the surface area of the interlocking bond forces at mineral grain to grain contacts [2]. In most rocks the higher the surface area of mineral grain to grain contact the harder the rock becomes, for example;

a.) Decreasing porosity in rocks increases the surface area of grain contacts.

b.) Decreasing the size of mineral grains in the rock increases surface area of grain boundaries.

c.) The surface area of equate or irregular grains is greater than that of angular grains.

Sedimentary rocks generally have high porosity, a reflection of the processes of their formation and the nature of the cementing agent. As a result they are generally low in rock hardness (as shown in Table 2), and their grains are less tightly held together. Fine-grained and lower porosity igneous rocks, such as basalt and diabase (dolerite) are generally higher in rock hardness than that of coarser grained igneous rocks, such as granite, diorite, and gabbro.[5]

As a result, the mineral grains of fine-grained igneous rocks are more tightly held together than that of coarse-grained igneous rocks. In metamorphic rocks, where strong foliations have developed, rock hardness is generally lower due to the preferred orientation of mineral grains and the structural weaknesses these impose. However, in low grade metamorphism where a foliation does not develop, but the rock became more indurated (i.e. more compacted and lower porosity), rock hardness increases. This is the case for the rock slate, which is the indurated metamorphic form of the sedimentary rock shale.[2]

Table 2 The typical rock parameter (from Attewell and Farmer 1976)

Typical Rock Types	Compressive Strength (Mpa)	Tensile Strength (Mpa)	Shear Strength (Mpa)	Bulk Density (Mg/m^3)	Porosity (%)
Granite	100-250	7-25	14-50	2.6-2.9	0.5-1.5
Diorite	150-300	15-30	NA	NA	NA
Diabase	100-350	15-35	25-60	2.7-3.05	0.1-0.5
Gabbro	150-300	15-30	NA	2.8-3.1	0.1-0.2
Basalt	100-300	10-30	20-60	2.8-2.9	0.1-1.0
Gneiss	50-200	5-20	NA	2.8-3.0	0.5-1.5
Marble	100-250	7-20	NA	2.6-2.7	0.5-2
Slate	100-200	7-20	15-30	2.6-2.7	0.1-0.5
Quartzite	150-300	10-30	20-60	2.6-2.7	0.1-0.5
Sandstone	20-170	4-25	8-40	2.0-2.6	5-25
Shale	5-100	2-10	3-30	2.0-2.4	10-30
Limestone	30-250	5-25	10-50	2.2-2.6	5-20
Dolomite	30-250	15-25	NA	2.5-2.6	1-5
Steel	900-1500	NA	NA	NA	NA

*NA= Not Available

2.3 Rate of Penetration

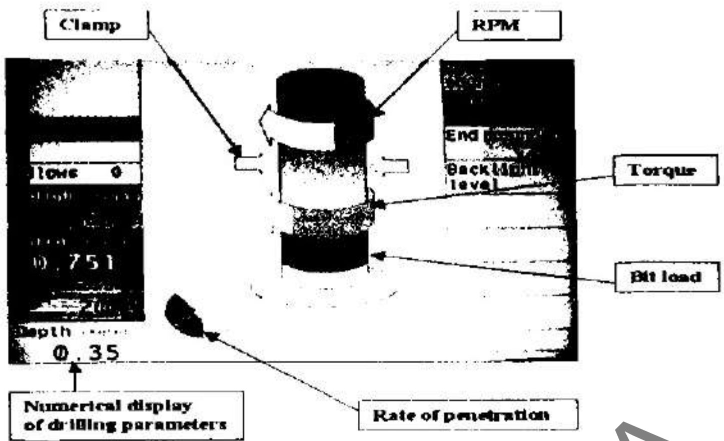


Figure 1 The drill string set

* Taken from; Adam T Bourgoyne Jr, 1991, "Applied Drilling Engineering," *SPE*, pp. 246-294.

The energy required to penetrate the rock layer is known as specific energy. This energy will penetrate the soil material like rock. The specific energy diagram often takes the shape of a typical cone penetration test (CPT) diagram [1]. The equation of the specific energy, *e* is shown below;

$$e = f/a + (2 \times 3.14 \times n \times t) / (a \times v) \qquad (1)$$

Where;

f = Bit load (lbs)

a = Drill bit area (in^2)

n = Rpm (rev/min)

t = Torque (lbin)

v = ROP (ft/hr)

The first term describes the energy from the static load on the drill bit and the second term describes the energy incurred by the rotation work. The dimension of the resulting *e* will be in megajoules per cubic metre (shown in Figure 1).

For Rate of Penetration (ROP), it is being classify as the rate of the hole cleaning. It can be calculated by various formulas as shown below;

$R = L_{pc} n_{bc} N$ --- (2)

Where;

L_{pc}= Effective penetration of each cutting element

n_{bc}= Effective number of blades

N = Rotary speed

There are some assumptions which should be considered in applying this equation. There are;

a.) The bit has a flat surface that is perpendicular to the axis of the hole.
b.) Each blade is formed by diamond laid out as a helix as show in the Figure 2.
c.) The stones are spherical in shape as shown in Figure 3.
d.) The diamond are spaced so that the cross-sectional area removed per foot is a. maximum for the design depth of penetration.
e.) The bit is operated at the design depth of penetration.

In order to apply the equation 2, the effective penetration of each cutting element and effective number of blades need to be defined. Here, the L_{pc} and n_{bc} are described below;

$L_{pc} = 0.67\ L_p$

and

$= 1.92\ (C_c/s_d) d_b\ (d_c L_p - L_p^2)^{1/2}$

Where;

C_c = Concentration of diamond cutter (carats/sq.in)

L_p = Actual depth of penetration of each stone (in.)

d_b = Bit diameter (in.)

d_c = Average diameter of the face stone cutters (in.)

s_d = Diamond size (carats/stone)

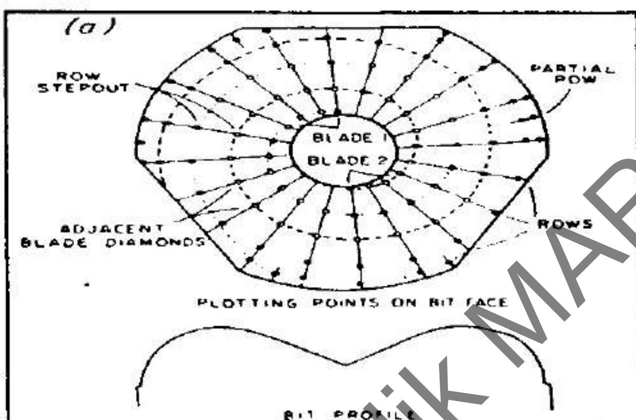


Figure 2 Diamond laid out as helix

* Taken from; Adam T Bourgoyne Jr, 1991, "Applied Drilling Engineering," *SPE*, pp. 246-294.

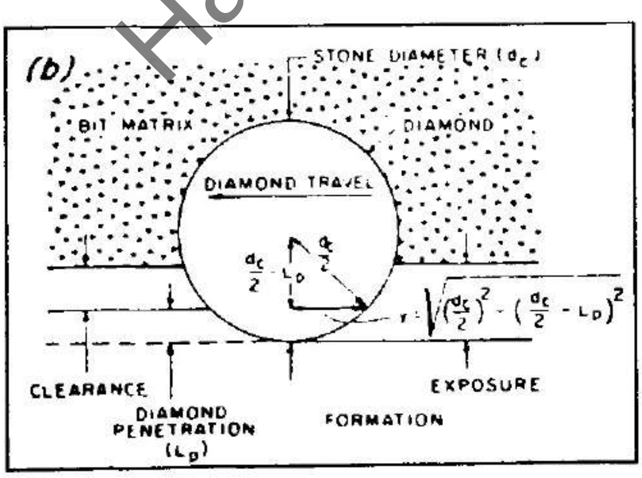


Figure 3 Spherical shape of stone

* Taken from; Adam T Bourgoyne Jr, 1991, "Applied Drilling Engineering," *SPE*, pp. 246-294.

2.4 Bit Lifetime

The life of a diamond drill/bit is determined by the number of holes or it can drill (parts machined). It is fairly difficult to estimate the life of diamond drill. Diamond drill life is affected by various factors such as the application, bond type, drill manufacturer, and experience of user in properly using the drill. The following considerations play a major role in diamond drill life [1];

a.) Hardness and abrasiveness of the material being drilled.

b.) Speed and power of drill.

c.) Amount of pressure used (feed rate).

d.) Proper use of coolant (type of coolant, coolant force, & direction).

e.) Drilling Depth.

f.) Material Holding Method.

g.) Operator experience (understanding Proper Diamond Drill Usage Principals and adjusting them as need to better fit their particular application & objectives).

h.) Overall age and condition of drilling equipment (precision, accuracy, & repeatability of drilling equipment used).

i.) Quality, hardness, sharpness, and mesh size of the diamonds.

j.) Hardness of the bond compared to the material being drilled.

k.) Experience and technology of manufacturer in keeping diamonds in the bond.

2.5 Drilling Cost

The most common application of a drilling cost formula is in evaluating the efficiency of a bit run. A large fraction of the time required to complete a well is spent either drilling or making a trip to replace the bit [5]. The total time required to drill a given depth ΔD, can be expressed as the sum of the total rotating time during the bit run t_b, the no rotating time during the bit run, t_c and trip time, t_t. The drilling cost formula is like below [4];

$$C_f = [C_b + C_r (t_b + t_c + t_t)] / \Delta D \quad (3)$$

Where;

C_f = Drilled cost / unit depth (ft)

C_b = Cost of the bit ($)

C_r = Fixed operating cost of the rig ($) / unit time independent of the alternatives being evaluated. (t)

t_b = Rotating time (hr)

t_c = Non rotating time (hr)

t_t = Trip time (hr)

The target of the project is to gain the lowest value in cost as the footage drilled increasing. As the drilling cost decreasing in time, the efficiency of the drilling bit need to be maintained by minimizing the possibility for the bit dullness. Therefore, the drilling operation can be further optimized in cost.

2.6 Parameter Limitation; Rock Properties

2.6.1 Rock Porosity

Porosity is defined as the ratio of the pore volume to the bulk volume of a material (expressed as percentage). It measure of the space available for accumulation of fluids. So the higher porosity value, the higher of rate of penetration (ROP) during the drilling processes.

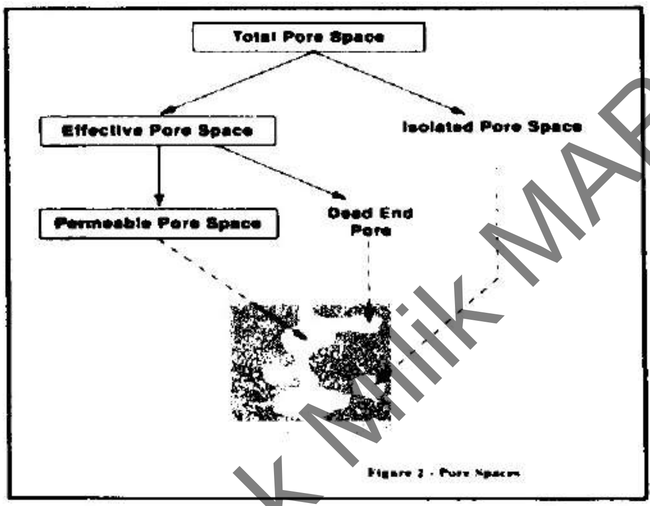


Figure 4 The porous media

* Taken from; William D. Mccain, Jr., 1988, "The Properties of Petroleum Fluids, *second edition*, 4, pp. 949-955.

From the figure shown above (as shown in Figure 4), the number of pore space will determine the rate of porosity [6]. The higher of porosity value the higher of oil and gas accumulation in the reservoir. Therefore, the project will study on the rock properties in term of porosity in reducing the damage to the bit cutter.

By applying mathematical approach, the porosity of the rock is calculated by using the below formula where we considering the pore volume, grain volume, and the bulk volume (refer to Figure 5). [6]

$$\text{Porosity} = \frac{\text{Pore volume}}{\text{Bulk volume}} \times 100\%$$

$$\text{Porosity} = \frac{\text{Bulk volume} - \text{Grain volume}}{\text{Bulk volume}} \times 100\%$$

$$\text{Porosity} = \frac{\text{Pore volume}}{\text{Pore volume} + \text{Grain volume}} \times 100\%$$

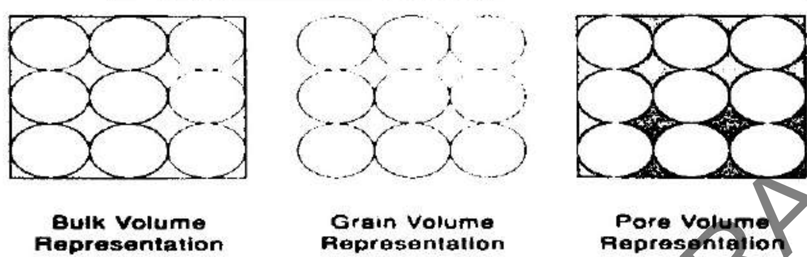


Figure 5 The volume representation

* Taken from; William D. Mccain, Jr., 1988, "The Properties of Petroleum Fluids, *second edition*, **4**, pp. 949-955.

However, the porosity is normally distributed. So we have to identify the average porosity in order to obtain the best value. The formula used is as below;

$$\phi_a = \frac{\sum_{i=1}^{n} \phi_i}{n}$$

ϕ_a is the mean porosity
ϕ_i is the porosity of the
i^{th} core measurement
n the number of measurements

The porosity of the rock is really dependent on the few factors where the petroleum engineer must deal with in reducing the bit damage. The factor that will affect the porosity ranges is as below;

a.) Packing of grains. Absolute size does not have a large impact.

b.) Particle size distribution (sorting). Wide size distribution leads to low porosity.

c.) Particle shape. Strong impact in sedimentary process.

d.) Cementing material. Clays and minerals allocated.

2.6.2 Rock Permeability

The ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies (as shown in Figure 6). Formations that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores [6].

Absolute permeability is the measurement of the permeability conducted when a single fluid, or phase, is present in the rock. Effective permeability is the ability to preferentially flow or transmit a particular fluid through a rock when other immiscible fluids are present in the reservoir (for example, effective permeability of gas in a gas-water reservoir). The relative saturations of the fluids as well as the nature of the reservoir affect the effective permeability.[3]

Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation. If a single fluid is present in a rock, its relative permeability is 1.0. Calculation of relative permeability allows for comparison of the different abilities of fluids to flow in the presence of each other, since the presence of more than one fluid generally inhibits flow. [6]

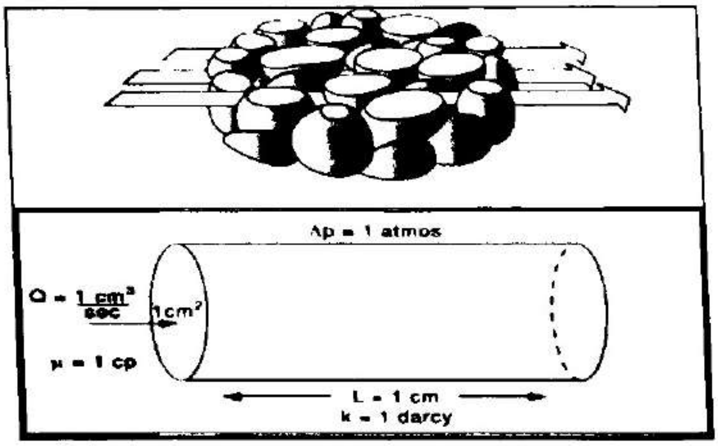
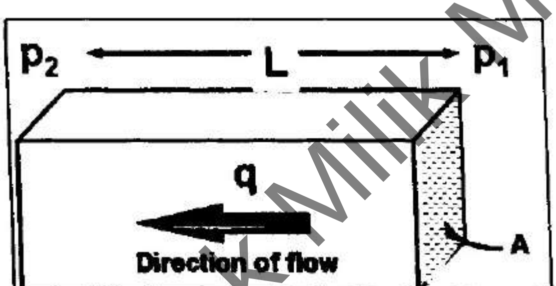


Figure 6 The rock permeability

* Taken from; William D. Mccain, Jr., 1988, "The Properties of Petroleum Fluids, *second edition*, **4**, pp. 949-955.

The permeability rate is calculated by using this formula;



$$k = \frac{q\mu}{A} \bullet \frac{L}{(p_1 - p_2)}$$

Where;

q = Flow rate (cm^3/s)

A = Cross sectional area of flow (cm^2)

P1-P2 = Pressure difference across the sample (atm.)

μ= Viscosity (cp)

L = Length of sample (cm)

k = Permeability (Darcy)

The permeability is also ranged to the various groups as in Table 3. The importance of the grouping method is we can determine the hardness of the rock layer while the drilling process is running. The higher of the permeability range, the lower of the bit damage.

Table 3 The permeability range

Classification	Permeability Range
Very Low	< 1 mD
Low	1 – 10 mD
Medium	10 – 50 mD
Average	50 – 200 mD
Good	200 – 500 mD
Excellent	> 500 mD

* Taken from; William D. Mccain, Jr., 1988, "The Properties of Petroleum Fluids, *second edition*, 4, pp. 949-955.

CHAPTER 3
METHODOLOGY

In ensuring the project run smoothly and successfully, the brief methodology need to be defined clearly. The explanation of the work procedure will be discussed in the next section. The flow of the project is shown below;

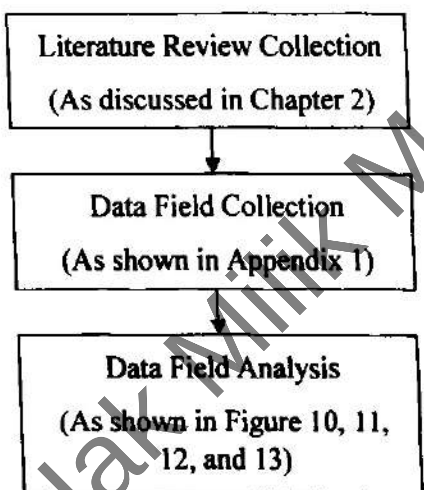


Figure 7 The methodology flowchart

3.1 Literature Review Collection

In finishing the project the collection of the literature review is put into effort. Here, various sources like internet, journal, and reference books are being used in ensuring the right data are selected.

3.2 Data Collection

Baram Field is located in Sarawak basin in Malaysia (refer to Figure 8). It is an offshore area where PETRONAS running their activities in gaining crude oil and gas. As shown below, the specific location of the study is presented in the map form. The scope of study is at Baram G108 (well name).

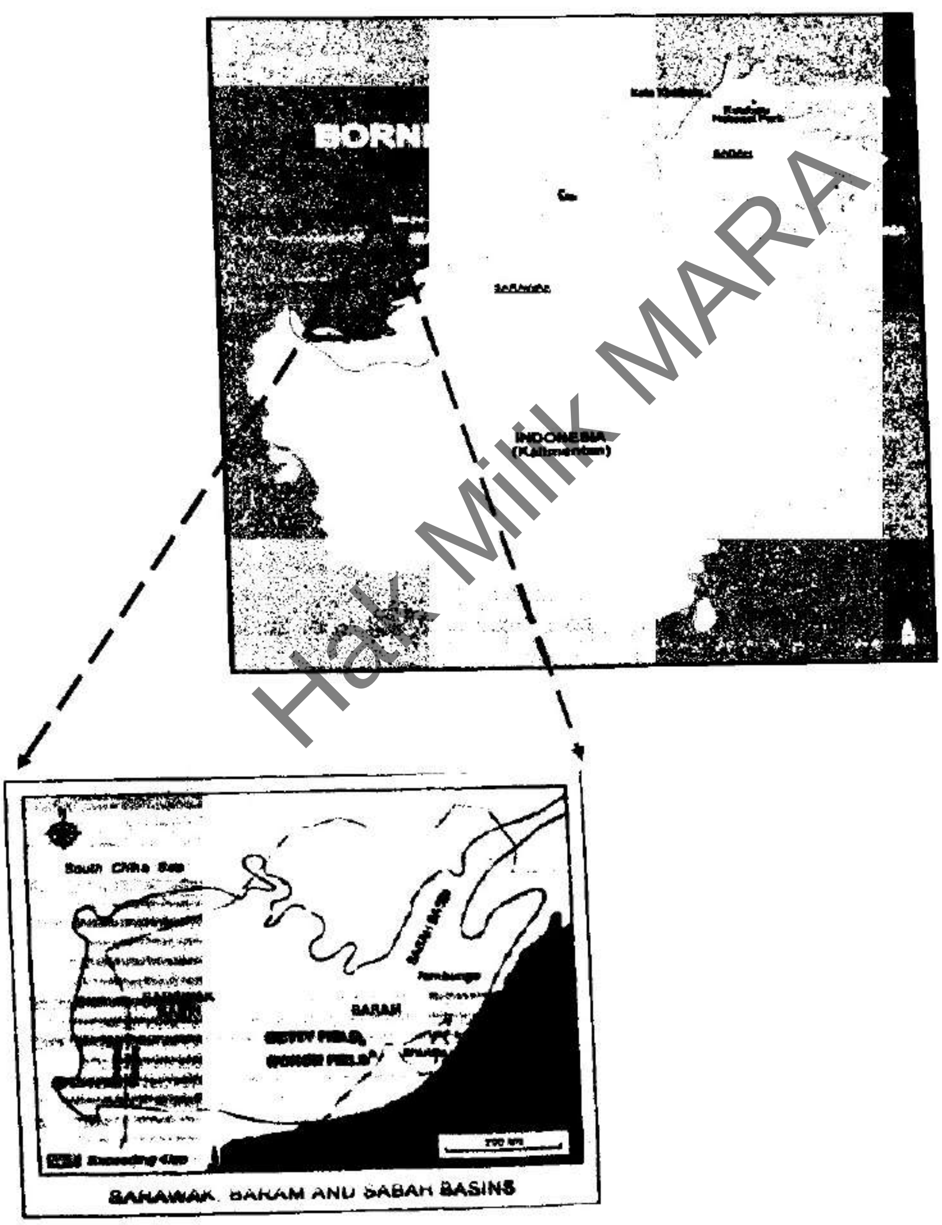


Figure 8 Map of the study location, Baram Field

The drilling record sheet (provided in the Appendix 1) was taken from PETRONAS CARIGALI. It contains various parameters in the drilling operation. However in this project research, the student will only focus on the bit hours, rate of penetration (ROP), RPM, and the footage drilled on the bit. The summary of the reading is shown in Table 4 below;

Table 4 The range value of the parameters involved

Parameters Involved	Min. Value	Max. Value
1.) ROP	17.67 ft/hr	693.24 ft/hr
2.) Footage Drilled	0.3 ft	8950.60 ft
3.) Bit Hours	0.1 hr	172 hr
4.) RPM	30 rpm	1600 rpm

3.2.1 Field History

Exploration for oil in the Baram Delta commenced in 1909. The first exploration well, Miri-1, was drilled in 1910. This well resulted in the discovery of the Miri Field that ultimately produced about 80 million barrels of oil before it was abandoned in 1972.

The first offshore exploration well, Siswa-1, was drilled in 1957 from a fixed platform constructed in shallow water. Unfortunately, the well did not encounter any hydrocarbons. The first offshore field was discovered in 1963 by the Baram-1 well drilled with jack up rig Orient Explorer. This success led to an increase in activities and opened the way to further discoveries in the offshore Baram Delta during the late 1960s and 1970s. The earlier exploration play was the Cycle V and VI topset sands in large anticlinal features, and drilling was terminated upon encountering overpressures. Recent exploration effort resulted in more gas discoveries in footwall closures along the nose of anticlinal features.

In 1988 a new PSC was awarded to Carigali (operator) and Shell to produce the 9 oil fields, namely, Baram, Bakau, Baronia, Betty, Bokor, **Fairly-Baram**, Siwa, Tukau, and West Lutong field under **Baram Delta Operations (BDO).** The Laila and Beryl gas field fall under the MLNG-Dua PSC which is held by Shell (operator) and Carigali.

3.2.2 Facies Succession and Depositional Environment

The facies successions was mapped in the Baram Field (refer to Figure 9). The detail study of the facies successions in the study is really needed in determining the formations at the Baram G108. Therefore, the bit performance analysis in penetrating the rock can be clearly identified later. The detail description are shown below;

1. Sharp-based, upward-coarsening SCS succession in characterised by thick (ca. 10m) amalgamated SCS sandstone abruptly overlying thinly interbedded HCS sandstones and mudstones. The thick SCS unit comprises several amalgamated units of fine-to very fine-grained HCS sandstones, punctuated in places by massive coarse-grained sandstone and interbedded mud clasts conglomeratic layers. The sharp-based SCS sandstone corresponds to a very sharp decrease in the gamma-ray log readings. The thick SCS sandstone is interpreted to be deposited during a rapid fall of relative sea level, resulting in shoreface progradation into mud-dominated inner shelf, thus giving the sharp-based characteristics.

2. Gradational-based, upward-coarsening HCS-SCS succession begins with laminated or bioturbated mudstones and interbedded, cm-thick, fine to very fine sandstone beds. This lower succession may contain thin layers of facies 1, 3, 5, 9 and cm-thick planar laminated sandstones. The sandstones beds thicken upwards, the proportion of HCS beds increases and may show amalgamated HCS beds. Further upward mudstone interbeds decrease in thicknesses and SCS sandstones predominate. The gradational vertical facies organisation suggests a progressive, gradual shallowing in a prograding, wave-dominated shoreface.

3. Fining-upward tidalsuccession characterised by an upward-fining, upward-shallowing succession of tide-dominated facies, e.g. thick,fine-to medium grained heterogeneous sandstone capped at the top by a flaser-bedded horizon. This succession is interpreted a th result of a slight shallowing of a sub-tidal, tide dominated environment. Its thickness and stratigraphic position suggest periods of localised and restricted tide-dominated sedimentation within a temporally more usual wave-and storm-dominated environment.

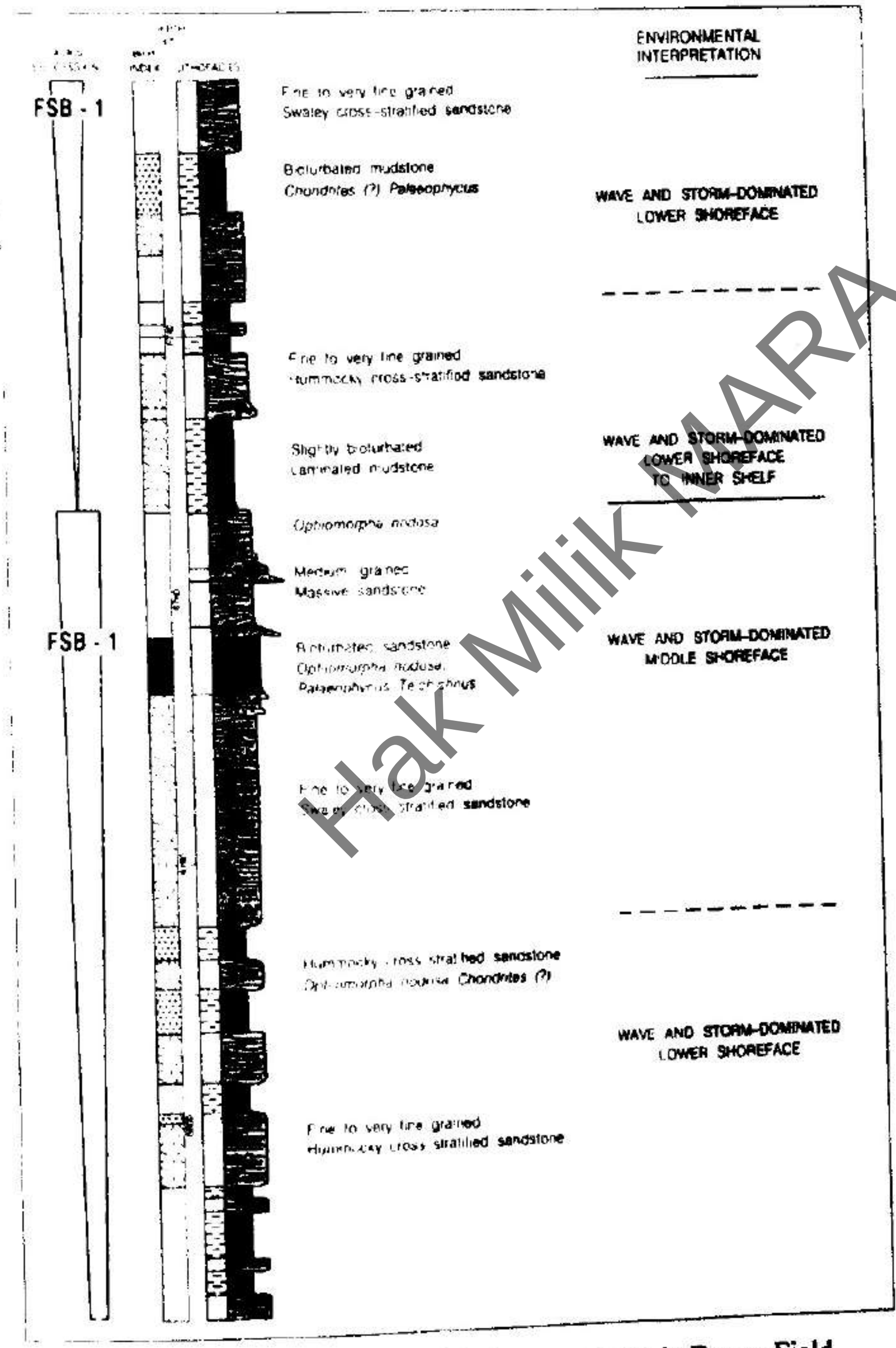


Figure 9 Sample of facies succession in Baram Field

3.3 Data Field Analysis

The data will be presented in the graph analysis form so the interpretation can be made. The correlation of the parameters (bit hours, ROP, RPM, and the footage drilled) involved will be later put into the studies so that the drill bit optimization can takes place.

CHAPTER 4
RESULT AND DISCUSSION

The detail analysis of the drilling operation in Baram G108 was carried out and the result will be presented in the graph form. Here, the interpretations of every graph will be discussed. The field summary is shown in Table 5 below;

Table 5 The summary of field record

Items	Detail
Name of the field	Baram Field
Well location	Baram G108
Bit used in the drilling operation	Polycrystalline Diamond Compact (PDC)
Bit Class	New Bit- USD 27,000

4.1 RPM versus Bit Hours and Footage Drilled versus RPM

Table 6 The correlation between bit hours, RPM, and footage drilled

Bit Hours (hr)	RPM (rev/min)	Footage Drilled (ft)
15.35	120	3974
18.39	100	2673
20.13	140	4977

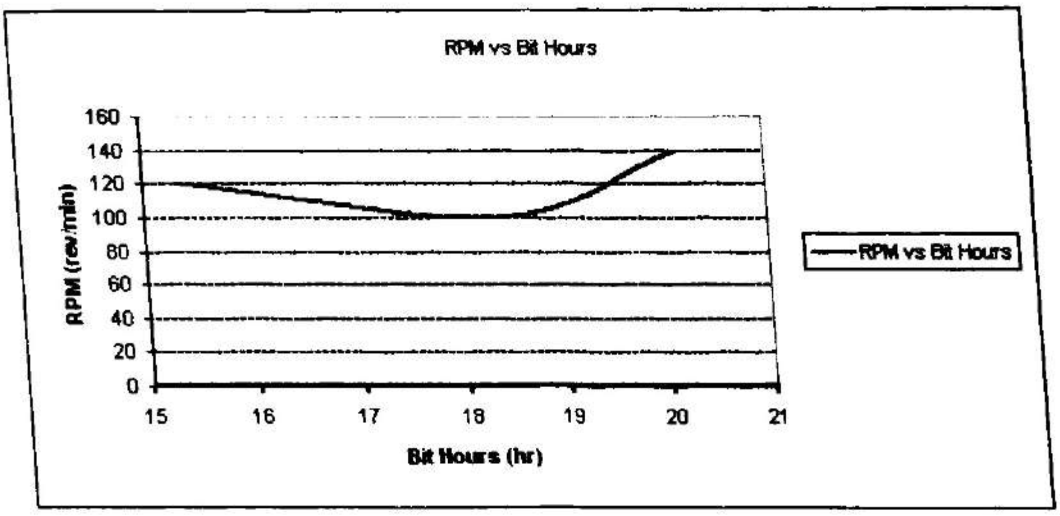


Figure 10 The graph of RPM versus bit hours

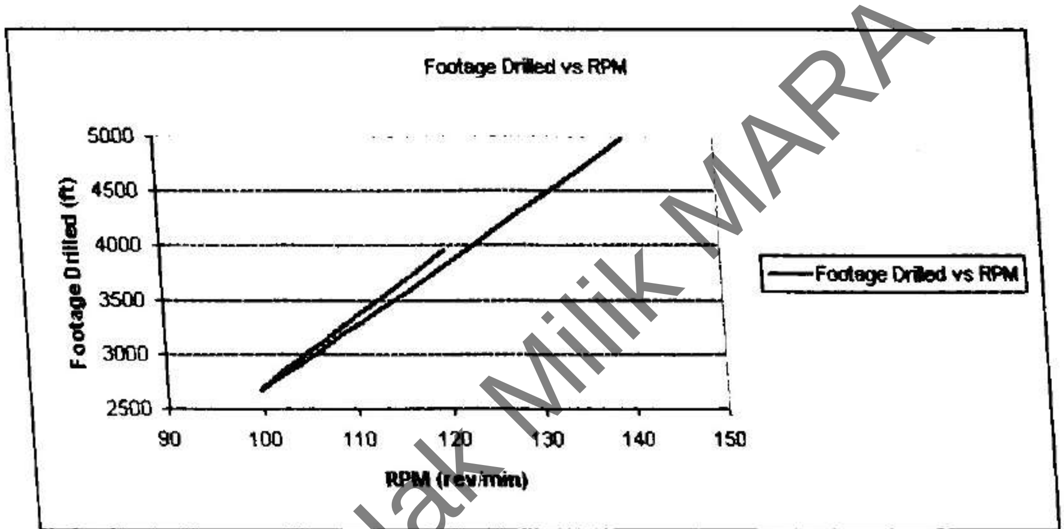


Figure 11 The graph of footage drilled versus RPM

From the graphs in Figure 10, the surface RPM drop at hour 18.39 contributes to the reduction of the drilled footage (as shown in Figure 11). This is caused by the changing of formation layer (eg. the bit which penetrating the medium formation is suddenly enters the harder formation like igneous rocks and quartzite) contribute to the inefficiency of the drilling operation. When this bit is used to drill the hard formation in which is deep and hot holes area, the drilling rate and lifetime of commercially available PDC bit are dramatically reduced. The reason behind it is the bit will become hotter during it runs. From the analysis, the impact and temperature loadings are increasing by the time of the drilling operation. In this case, the changing in formation will gives a difficulty to the bit to penetrate the rock and the soil. Therefore, in order to fail the rock and the soil, the bit need to shear and grind the formation at higher energy. As the drilling progresses, the friction between the bit and the hard formation will produce a high impact and temperature loading. Once the amount of these loadings is exceeding the bit operating condition, the tear and wear will takes place. Here, the failure in individual PDC cutter is due to principally to increased the impact loading and the higher drilling temperatures associated with an increased wear flat between the bit and the hard rock being cut (the temperature limitation to PDC bit is 750°C). In order to counter the problem, the application of TSP (Thermally Stable Polycrystalline) cutter is strongly suggested because it can operate up to 1200°C by having very minimal wear rate to it.

4.2 ROP versus RPM

Table 7 The correlation between Min. RPM and the ROP

Min RPM (rev/min)	Rate of Penetration (ft/hr)
26	75
50	120
100	189.69
120	84.76
140	60

Table 8 The correlation between Max. RPM and ROP

Max RPM (rev/min)	Rate of Penetration (ft/hr)
50	25
130	70
140	85
140	84.76
200	189.69

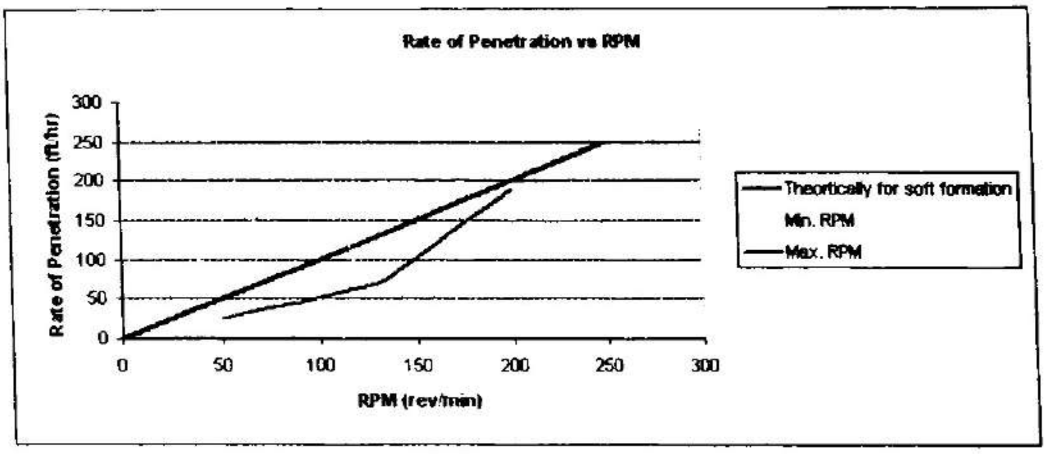


Figure 12 The graph of ROP versus RPM

From the graph shown in Figure 12, the rate of penetration is increasing during the increment of RPM. The comparison between parameters (Min. RPM and Max. RPM) are basically based on the theoretical performance for the soft formation. In early stage of the operation, the ROP with the 'Min. RPM' is increasing until it reaches 189.69 ft/hr. However the graph begins to deflect downward until it reaches 60 ft/hr of penetration. Here, the presence of the hard formation like igneous rocks (some metamorphic rocks and fine-grained sandstones) and quartzite (dense fine-grained igneous rock) at the Baram G108 influences the bit to penetrate inefficiently. The different output is obtained when the drilling operation run at 'Max RPM'. The ROP is continuously increasing with the increment of the RPM. Here, there are two choices that drillers can select as their operating speed which is whether to run with Min. RPM or Max. RPM. If they select to run at Min.RPM, the time taken to complete the operation will be longer compared to using the Max. RPM. This is because the penetration of the rock will only run at high efficiency in early stage of the drilling operation but once the ROP is drops, the efficiency is not being there anymore. The different outcome is obtained when running at Max. RPM where the efficiency is increasing and the time taken to complete the well is slightly faster than running by using Min. RPM. Other than that, the Min. RPM will gives the lower cumulative footage drilled compared to the system that run at Max. RPM. Therefore, the drillers need to ensure that the system always run at Max RPM so that the expected depth can be achieved.

4.3 Drilling Cost

From the Data Field studies, the drilling cost can be presented in the graph form. The study which takes place in Baram G108 has few constant parameters that are shown below;

a.) Bit Cost = USD 27, 000.
b.) Rotating Time + No rotating Time + Trip Time = 24 Hours.
c.) Rig Rate = USD 6,667/ Hour.
d.) Drilling Rate = 1.5 Day/ 300 m.
e.) Rotating Time = to be assumed 14.8 hours.

Sample calculation:

$C_f = [C_b + C_r (t_b + t_c + t_t)] / \Delta D$

C_f = [USD 27,000 + USD 6,667/Hour * (24 Hours/day)] / (84.76 ft/rx14.8 hr)

C_f = USD 149.00

Table 9 The correlation between mean depth and drilling cost

Depth (ft)	Mean Depth (ft)	Drilling Cost (USD/ft)
0-1271	920	149
1272-2627	1670	167
2628-3631	2940	253
3632-4765	4000	349
4766-5000	4000	420

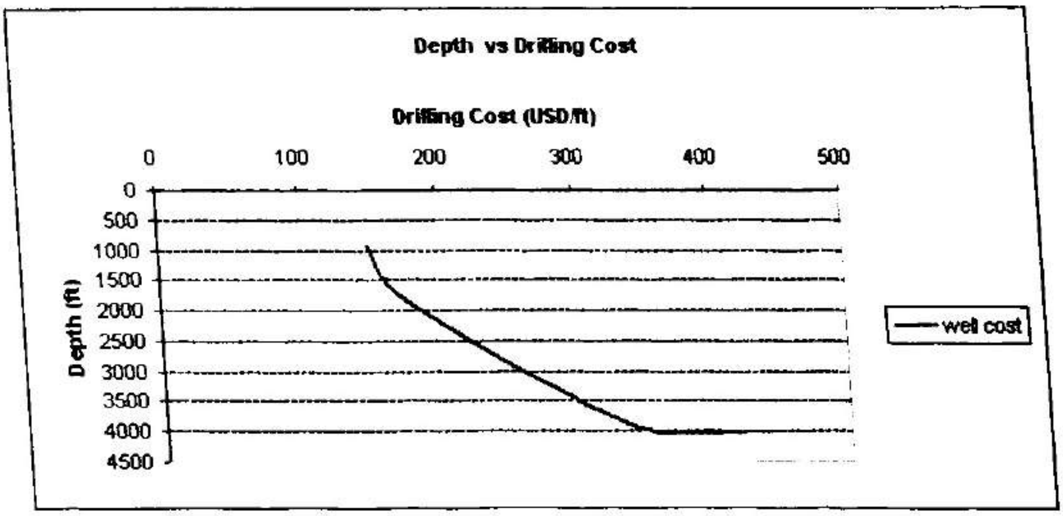


Figure 13 The graph of depth versus drilling cost

In most drilling the cost increases continuously as the depth of the dig advances. However, in this instance and with reference to the graph (as shown in Figure 13), the cost is actually decreasing as the dig progresses. The drilling cost is expected to reduce further while at the same time gain greater the drill footage. As we can see from the diagram, the graph begin to deflect upward at the mean depth of 4000 ft and the drilling cost of USD 420/ft. Here, the drilling cost is increasing in value by having no more penetration of the rock. Here, the dullness of the bit is occurring which is caused by the tear and wear during penetrating the hard formation (as discussed in the graph in Figure 10, 11, and 12). Therefore, the recommendation to change the bit is highly needed.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

As a whole, the study on the drilling operation at Baram G108 in Baram Field at Sarawak basin has brought the positive output. The summary of the conclusion of the project is shown below;

[1] The optimum value of the footage drilled in Baram G108 is 4977 ft (1516 m), ROP is 189.69 ft/hr, and RPM is 200 rev/min (taken from the graph in Figure 10 and 11). In the project study, PDC bit is damage and the performance is highly affected by it. This is because any harm to the bit manages to ruin the overall parameters involved in drilling operation.

[2] In the graph (as shown in Figure 23), the Min. RPM gives a very impressive performance in early stage of drilling processes, however it produce an undesirable output suddenly (the ROP drops from 189.69 ft/hr to 60 ft/hr). While the Max. RPM give a positive outcome where the ROP is directly proportional to the increment of RPM itself (the ROP increasing continuously from 25 ft/hr to 189.69 ft/hr).

[3] Since the bit is damaged, thus the driller cannot reuse it for the next operations. From the graph (refer to Figure 13) of drilling cost analysis, the bit is no longer efficient at mean depth of 4000 ft (1219 m) by having USD 420 per feet.

However, there are some recommendations that need to be highlighted in order to ensure to obtain the better performance in the future;

[1] Since the drilling performance is highly affected by the formation changes while at the same time the PDC bit cannot run efficiently, the proposal to use TSP (Thermally Stable Polycrystalline) bit is recommended. The TSP bit able to withstand the higher degree of heat (up to 1200°C) compared to PDC bit (which is only up to 750°C). The wear rate also can be minimized.

[2] The drillers need to ensure that the system always run at 'max RPM' so that the better depth can be achieved while the optimum ROP can be maintained through out the operation.

[3] From the drilling cost analysis (as shown in Figure 24), the dull bit cannot be reuse for the next operation because it will influence the drilling cost to grow bigger and bigger while having no penetration. Here, the recommendation to use the new bit like TSP is strongly recommended so that the performance as well as the drilling cost can be optimized.

The suggestion to continue the further studies on the project is strongly encouraged where other parameters that not being discussed in this stage can be identified so that the better output will be gained in the future.

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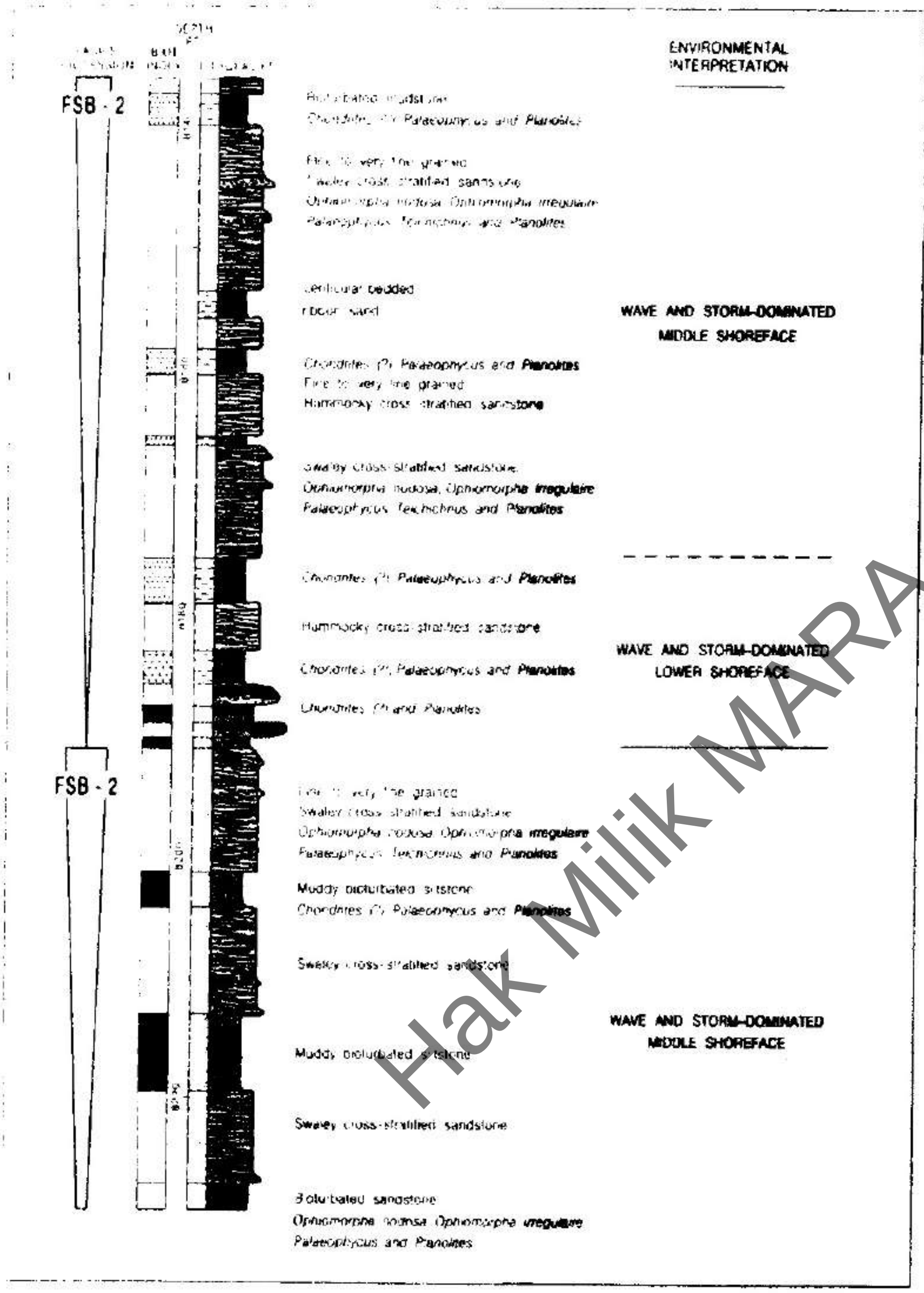
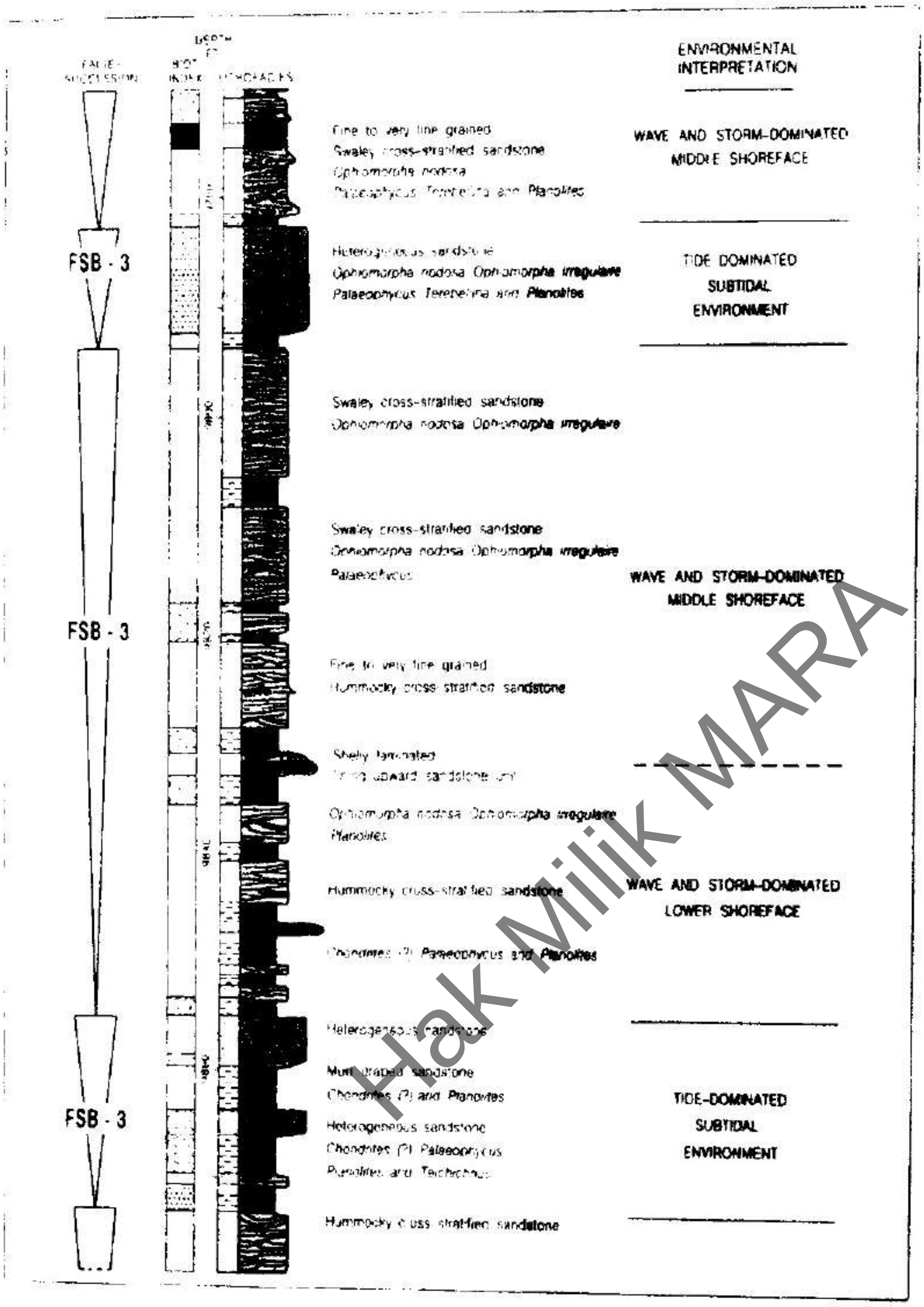
APPENDICES

Field N	Legal Well Name	Serial N	Nominal	Bit Gro	Bit Clas	Bit Cost	Hours on	Rate of	Cumula	Cumula	Cumula	Maximum	Minimum	Minimum R
BARAM	BARAM-G10B	6275	8.5 PD		N	27,000	15.36	84.76	98.05	40.53	3,974.00	20,000	12,000	120
BARAM	BARAM-G10B	6275	8.5 PD		N	27,000	18.39	75.31	106.16	25.18	2,673.00	20,000	10,000	100
BARAM	BARAM-G10B	6275	8.5 PD		N	27,000	20.13	49.83	82.05	60.66	4,977.00	20,000	16,000	140
BARAM	BARAM-G10B	6275	8.5 PD		N	27,000	6.79	189.69	189.69	6.79	1,288.00	18,000	10,000	100
BARAM	BARAM-A BA-20ST3	79048	8.5 PD		N	0	5.09	97.84	97.84	5.09	498	10,000	8,000	70
BARAM	BARAM-A BA-20ST3	79048	8.5 PD		N	0	0	97.84	212.97	5.09	1,084.00	10,000	8,000	70
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	0	99.68	160.9	32.3	5,197.10	15,000	15,000	120
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	2.37	99.68	160.9	32.3	5,197.10	15,000	15,000	120
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	10.76	129.9	165.75	29.93	4,960.90	20,000	15,000	120
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	5.86	162.93	185.87	19.17	3,563.20	20,000	15,000	100
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	10.15	187.16	195.97	13.31	2,608.40	25,000	15,000	100
ANGSI	ANGSI A-30	108405	12.25 PD		N	0	3.16	224.27	224.27	3.16	708.7	15,000	10,000	100
BARAM	BA-15S1	109917	6 PD			12,000	6.3	45.4	42.84	11.6	497	4,000	2,000	100
BARAM	BA-15S1	109917	6 PD			12,000	5.3	39.81	39.81	5.3	211	4,000	2,000	100
BARAM	I	111370	12.25 PD		N	0	0.6	258.33	258.33	0.6	155	8,000	5,000	50
BARAM	I	111370	12.25 PD		N	0	10.3	84.27	110.34	32.4	3,575.00	20,000	5,000	60
BARAM	I	111370	12.25 PD		N	0	9.57	97.91	122.49	22.1	2,707.00	20,000	5,000	60
BARAM	I	111370	12.25 PD		N	0	11.2	118.57	112.45	43.6	4,903.00	25,000	5,000	60
BARAM	I	111370	12.25 PD		N	0	11.93	136.37	141.26	12.53	1,770.00	10,000	5,000	60
BARAM	I	111370	12.25 PD		N	0	0.5	112	112.01	52.7	5,903.00	20,000	5,000	80
BARAM	I	111370	12.25 PD		N	0	0	112	112.01	52.7	5,903.00	0	0	0
BARAM	I	111370	12.25 PD		N	0	8.6	109.77	112.01	52.2	5,847.00	20,000	5,000	60
BARAM	BARAM-E111 ST1	118188	8.5 PD			0	5.4	96.11	91.77	13	1,193.00	15,000	5,000	120
BARAM	BARAM-E111 ST1	118188	8.5 PD			0	0	0	153.77	13	1,999.00	15,000	5,000	120
BARAM	BARAM-E111 ST1	118188	8.5 PD			0	7.6	88.68	88.68	7.6	674	15,000	5,000	120

Appendix 1: The Sample of Drilling Record Sheet



Appendix 2: Facies Succession at Baram G108



Appendix 3: Facies Succession at Baram 96- ST1